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CROSSROADS IN ELECTRIC UTILITY PLANNING AND REGULATION

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Edward Kahn

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FOREWORD

This manuscript represents a written version of lecture notes given in Energy and Resources 281 at the University of California, Berkeley, in the Fall of 1983. These notes are intended to form the basis of a textbook on electric utility planning and regulation. Although the current version has been reviewed within the academic community, the utility industry and state regulatory agencies, it is the purpose of this publication to solicit further review.

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CROSSROADS IN ELECTRIC UTILITY PLANNING AND REGULATION

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Chapter 1

ELECTRIC UTILITIES AT THE CROSSROADS

1.1 Introduction

For decades there were clear rules to the electric utility game. It was a growth industry in which prices fell and profits rose as demand expanded. Investors were happy, utility regulators were popular, and utility executives lived tranquil lives. Then along came the 1970's and everything changed, generally for the worse. The oil price revolution was the single most de-stabilizing factor for the electric utilities, as much for its indirect effects as its direct ones. Suddenly the cost of everything the utilities needed went up very rapidly. Electric utilities require enormous amounts of capital to finance expansion. In the 1970's the cost of money, the cost of power plants, and the cost of fuel grew far beyond the expectations of conventional wisdom. In short, electricity became an increasing cost industry and its growth slowed markedly.

The transition from declining to increasing cost was painful. Investors suffered, utility regulators became unpopular and utility executives no longer lived tranquil lives. Electricity became a highly politicized industry. New strategies emerged from these political conflicts which called into question the traditional wisdom. The revolutionary re-definition of goals and objectives which came about in this process shook the foundations of regulation.

In this introduction we sketch these changes briefly. We start in Section 1.2 by characterizing the declining cost era. This is most dramatically illustrated by the career of Samuel Insull. In Section 1.3 we describe the transition from declining to increasing cost conditions. The task of regulation changes with these economic fundamentals. New strategies and challenges to traditional institutions became apparent. So profound were these changes that the nature and structure of the traditional utility firm began to be questioned. The rationale for the vertically integrated electric utility is sketched in Section 1.4. We outline the challenges to this structure.

This chapter goes quickly over difficult and controversial territory. The drama will be described more fully in subsequent chapters.

1.2 Scale Economies: The Historical Background of a Former Growth Industry

Electricity use and electric utility companies grew enormously in the first seventy years of this century. This long record of growth was driven by the realization of great scale economies. Larger markets meant larger, more efficient plants, which led to lower costs and more growth. To understand this process it is useful to illustrate it with concrete examples. The flavor of the industry's dynamic expansion is best embodied in the personality and achievements of its largely forgotten master builder, Samuel Insull. His career is both an emblem of the past and a forewarning of later developments.

Insull, born in England, came to America as a young man to become personal secretary to Thomas Edison. He participated in Edison's relations with what was to become the General Electric Company. Learning the intricacies of high finance as well as high technology from this experience, he went out on his own at the turn of the twentieth century to direct the development of the Commonwealth Edison Company of Chicago. Insull built up this utility through a combination of technical, marketing, financial and political skills. Commonwealth Edison not only unified the many small competing companies in Chicago, but Insull also began the process of rural electrification. This would eventually enable electric utilities to become large regional entities, serving ever increasing demands to all segments of society.

Before World War I, however, rural electricfication was a piecemeal process. Only small isolated systems existed, serving typically a single small town. In 1911, Insull began an experiment in Lake County, Illinois designed to link up a number of these small systems with a high voltage transmission network. The production economies achieved by this expansion were so substantial that the extra investment could be paid for easily, profit margins more than doubled, and customer prices were reduced at the same time.

Insull presented the results of the Lake County experiment in a famous address to the Franklin Institute in 1913. Tables 1-1 and 1-2 are the data summaries he offered at that time. Table 1-1 shows the changes on the demand side. In the two years from 1910 to 1912, the unified system doubled the number of towns served, more than doubled customers, connected load and kilowatt-hour sales. At the same time prices declined 18% from almost 9¢/kWh to about 7 $^1/_4$¢/kWh. The aggregated markets created a "more efficient" load, in the sense that it was easier to serve. The maximum demand on the system only went up 68% (963kW vs. 573kW) even though total sales (kWh) went up 2.7

times. This meant the load was smoother in nature and so could be served by more continuous operation of the most efficient generating units. Table 1-1 uses the load factor as a measure of this smoothness. Load factor is typically defined as the ratio of average to peak loads. The unified system shows a load facter twice as high as the separate systems.

The effect on cost of the consolidated system is shown in Table 1-2. On the whole, investment requirements are greater for the larger system. This will turn out to be an invariant feature. Growth is capital intensive. The rationale for increasing capital expenditures is that they are productive when efficiency gains are considered. In this case there are two offsetting effects at work. First, the cost per kW of generating capacity declines by 30% ($178 vs. $122), due to traditional scale economy for individual power plants. Larger generating stations can be built to serve the aggregated loads. These larger stations will bring enormous reductions in unit operating costs for fuel and maintenance. Offsetting this is the extra need for transmission and substation facilities. The unified system must bear these additional costs. They overwhelm the scale economy in capital cost for generation.

Fixed charges per unit kW are twice as large in the unified system, compared to the isolated ones. When these fixed charges are spread over units of production, however, the two systems have comparable fixed costs. This is due to the load factor improvement from aggregation. Although each unit of capacity costs twice as much as in the small systems, the large system uses capacity twice as intensively. The unit fixed cost is gvien by

$$\text{Unit Fixed Cost} = \frac{\text{Fixed Charge/kW}}{\text{Load Factor} \times 8760} \; . \qquad (1\text{-}1)$$

In particular

$$1.62¢/\text{kWh} = \frac{\$20.85}{.146 \times 8760} \; ,$$

and

$$1.68¢/\text{kWh} = \frac{\$40.60}{.289 \times 8760} \; .$$

The real scale economy comes from the steep drop in operating costs. Fuel cost

Table 1-1

LAKE COUNTY EXPERIMENT, GENERAL STATISTICS

	Separate Management (1910 Conditions)	Unified Systems (1912 Conditions)
Population Served	15,395	22,188
Number of Towns Served	10	20
Number of Customers	1,422	3,457
Connected Load in Kilowatts	2,033	4,503
Kilowatt-Hours Sold	699,574	1,898,978
Kilowatt-Hours Sold per Capita	45	86
Income	$62,371	$136,694
Income Per Kilowatt-Hour	8.9¢	7.26¢
Income Per Customer	$43.86	$39.54
Income Per Capita	$ 4.05	$ 6.16
Maximum Kilowatts	573	963
Annual Load Factor	14.6%	28.9%

Table 1-2

LAKE COUNTY EXPERIMENT
COMPARISON OF COST OF ENERGY

	1910	1912
Investment Per Kilowatt of Maximum Demand		
Generating Station	$178	$122
Substation	...	70
Transmission	...	190
Total	$178	$382
Fixed Charge of Investment Per Kilowatt of Maximum	$20.85	$42.60
Maximum Kilowatts	573	963
Load Factor	14.6%	28.9%
Costs Per Kilowatt-Hour at Local Plant or Substation		
Fuel	2.04¢	.61¢
Other Operation, including Substation and Transmission	3.42¢	.56¢
Fixed Charges on Investment	1.62¢	1.68¢
Total Costs*	7.08¢	2.85¢

*Showing a saving in supplying the district from unified power supply and transmission system of 4.23 cents per kilowatt-hour.

per unit falls 70%. This is due to improved combustion efficiency and perhaps lower fuel prices for larger quantities purchased. Operations and maintenance costs per unit decrease almost 85%, probably due to decreased labor requirements.

The net result of unification is an increased profit margin. Although Insull does not explicitly perform the subtraction, it is easy to see that unit profits go from 1.82¢/kWh to 4.41¢/kWh (8.9 - 7.08 and 7.26 - 2.85). The fundamental fact behind these figures is that consumption has expanded rapidly, enabling a more efficient pattern of production to be constructed; only a small part of the efficiency gain goes to lower consumer prices. Producers retain the bulk of the productivity increase as profits.

Over time utility operators such as Insull plowed their profits back into expansion. Larger and larger systems were constructed, requiring very substantial capital investment. Among his many innovations Insull introduced the mass sale of electric utility common stock as a means of financing expansion. In its original conception this was an astute political move. Insull wanted his utility customers to share in company profits through stock ownership. This would create a political constituency to support the expansion of his utility franchises through the purchase and consolidation of smaller companies.

Through the decade of the 1920's this strategy was widely imitated throughout the industry. The principal form of expansion became the utility holding company whose assets were shares of common stock in operating utilities. The speculative fever of the time soon transformed this growth process into abusive directions. Holding companies purchased one another, creating financial pyramids based on exorbitent estimates of underlying value. When the stock market crashed and industrial activity began to contract, the holding company bubble collapsed. The large group of investors who shared both real economic profits and speculative gains lost large amounts of money. In the political reaction which followed, Insull was painted as a principal villain.

Thurmond Arnold, founder of Arnold and Paxer, a venerable Washington law firm wrote about this period in his classic study The Folklore of Capitalism. He expressed the common opinion of the time in the following way.

> "...Once an organization has become so respectable that it is a proper one for widows and orphans to trust, great pressures exist

> to use that respectability to get all the funds possible. Then, at the height of its powers when it is most respected, it becomes the worst organization for widows and orphans to trust...It is always the most respectable organizations which levy the heaviest tribute. Frankly speculative organizations collect money from a different source and cause much less suffering. It was Insull, not Capone, who wrecked the financial structure of Chicago."

The scale economy, growth and expansion strategy which Insull epitomized suffered a brief setback in the 1930's. Industry data shows a slight decline in consumption in the early part of this decade, before resumption of the growth path. New uses were found for electricity, however, and the old pattern re-emerged in the late 1930's. One of the great marketing success stories of this period was the domestic electric refrigerator. This appliance only came into wide usage as utilities sought to expand residential electricity use to compensate for reduced industrial sales. Wainwright's History of the Philadelphia Electric Company recounts this story as a great strategic triumph.

The financial collapse of the holding company empires brought a new level of utility regulation. The Securities Exchange Commission brought federal government authority into the investment arena to guarantee that the financial abuses of the 1920's would not be repeated. The political backlash against private electric utilities also supported government entry into electricity supply and distribution through agencies such as the Tennessee Valley Authority, Bonneville Power Administration and Rural Elecrtification Administration. Investor owned utilities were anxious to forget Insull, even if they did not forget his basic business strategy.

Among the many forgotten lessons of this experience was the intensity of public controversy when electric utility management failed in its public service functions. Being a highly visible and highly regulated industry makes electric utilities particularly vulnerable to disappointed public expectations. This vulnerability and disappointment would recur in the 1970's when the declining cost era of the industry came to an end.

1.3 Transition from Declining to Increasing Cost

Scale economies simply mean that bigger is cheaper. The technological conditions which create such happy outcomes connot be expected to continue forever. Sooner or later diminishing returns set in. In the case of electricity a number of external factors came together in the 1970's and transformed the cost structure. Fuel costs escalated due to OPEC cartel actions and their spillover into non-oil fuel markets. Figure 1-1 shows these changes to 1976. Current oil prices are roughly 2 1/2 times as great. The cost of power plant construction also increased. Figure 1-2 shows the Handy-Whitman Index of material and labor construction costs and the cost per kilowatt. Again these data only go through the mid-1970's, and current prices are 2-3 times greater.

Figure 1-3 shows the change in both real and nominal electricity prices along with a representation of the growth in production over a ninety year period. It is clear that the period of declining cost conditions comprises the bulk of the history of the electric utility business. The regulatory procedures which developed during this period addressed the politically pleasant task of deciding how much lower prices ought to be. The issues which tended to dominate regulatory attention during this period were the valuation of capital assets (or "rate base") and determination of a fair rate of return to stockholders. The process is illustrated schematically in Figure 1-4.

The basic process of regulating rates involves just dividing estimated revenue requirements by estimated sales. It is typical to separate revenue requirements into a variable portion reflecting operating costs, and a fixed portion reflecting capital costs. Since operating costs are easily audited, there was seldom much conflict over these. Most regulatory attention in the declining cost era was devoted to determining the value of capital invested (rate base) and fixing the level of reasonable earnings. Because of the underlying scale economies, new capital investment would always lower operating costs. As long as the utility rates are based on old data about costs (i.e., before the cost reducing investment) then revenues based on those rates will be "too high." This means that profit margins are yielding a higher return to stockholders than the regulators deem reasonable. To correct this, the regulator lowers the price to consumers so that only "required revenues" are produced.

Thus the process of price regulation under declining cost can be thought of as a movement from existing data on sales, current revenues and operating costs toward the

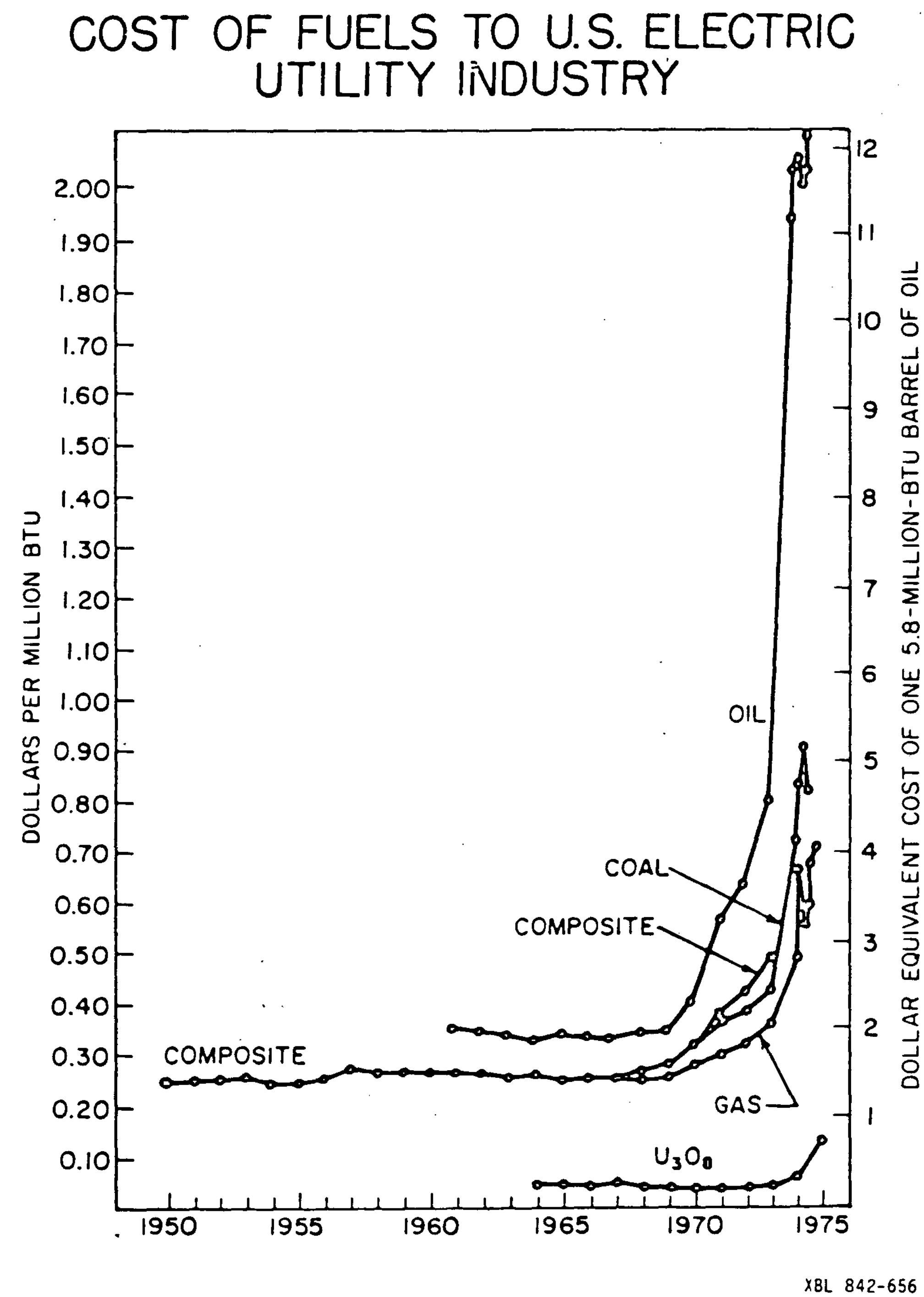

Figure 1-1 **Cost of fuels to U.S. electric utility industry**

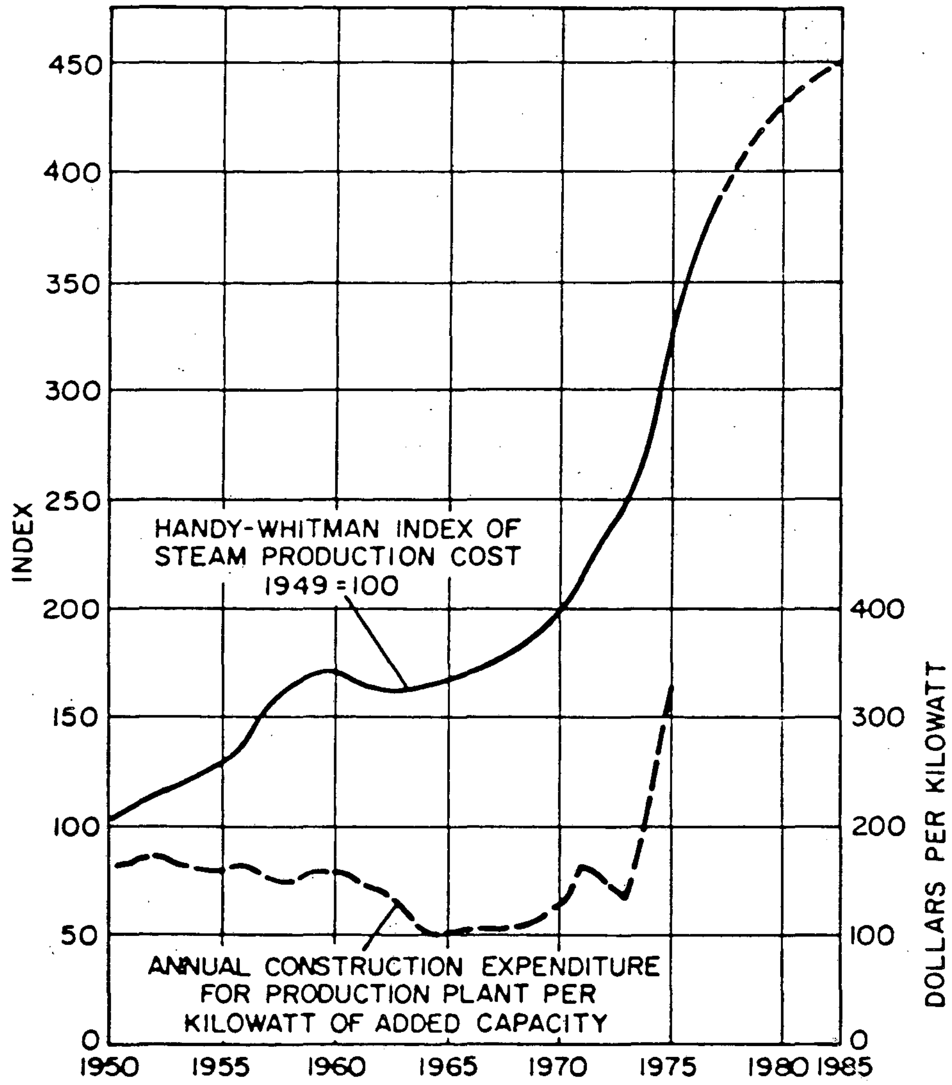

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Figure 1-2 Handy-Whitman Index and cost per kilowatt

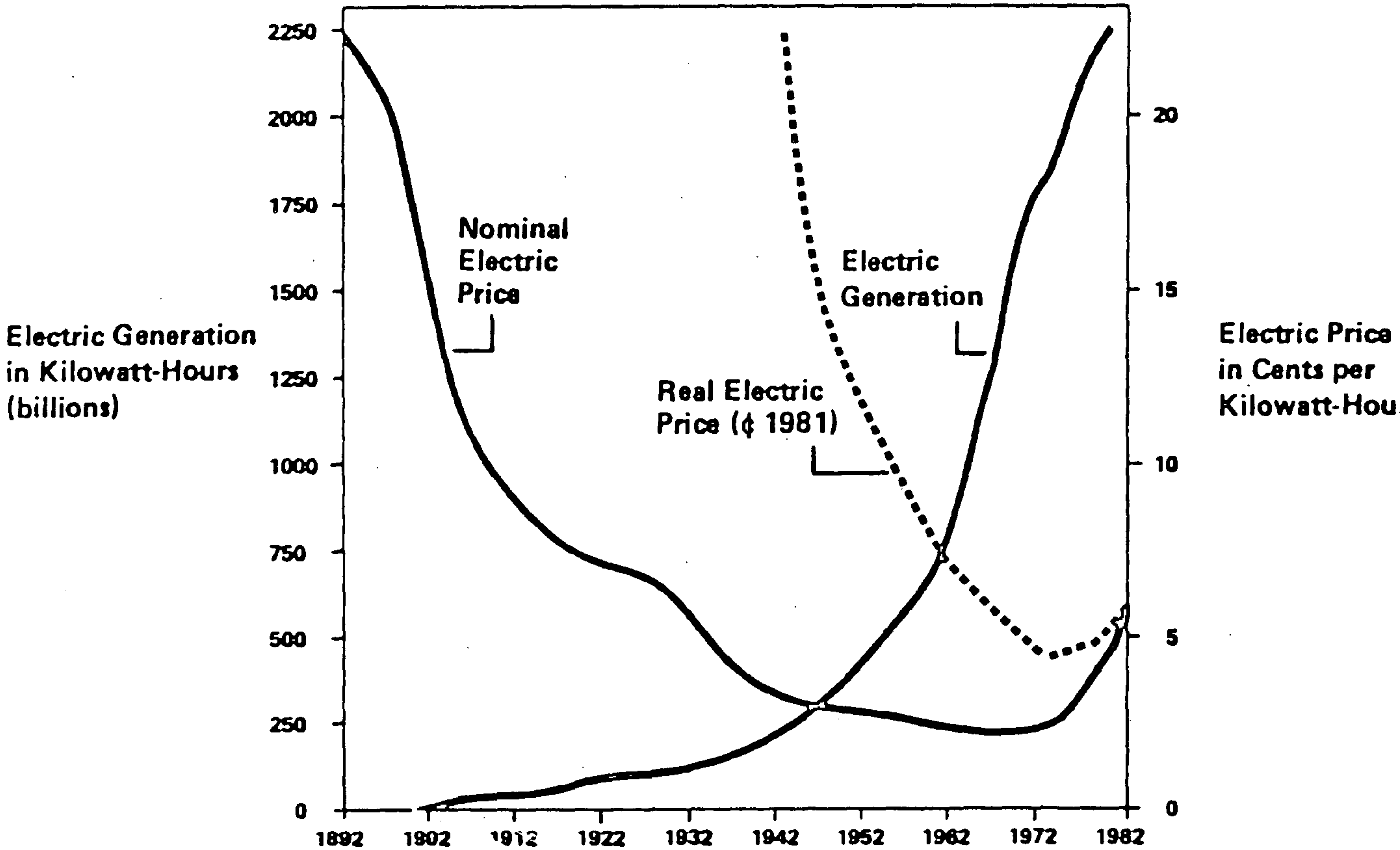

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Figure 1-3 U.S. electrical generation and price

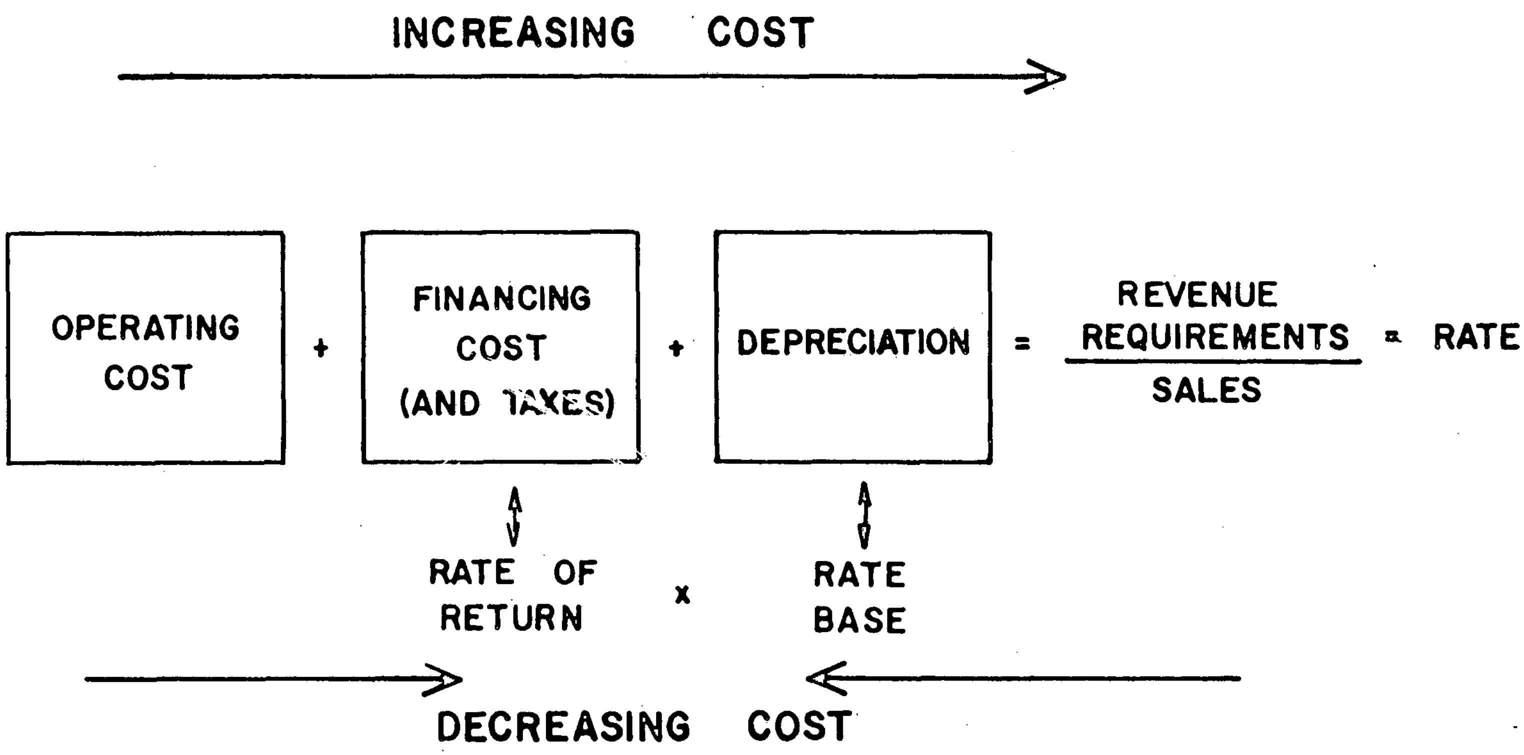

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Figure 1-4 Components of cost and their relation to rates ultimate goal of a "prepar" rate base and rate of return. Having found these, then a new rate is easily found by estimating required revenues and dividing by sales. The basic procedure is illustrated in Figure 1-4 as a movement toward the center of the diagram.

The basic procedure under increasing cost may look somewhat similar, but is in fact qualitatively different. The most obvious and fundamental difference is the outcome. Under increasing cost conditions, rates always go up. There can also be an inherent dynamic forcing up rates because of inadequate demand forecasts. Since rates are the ratio of revenue requirements to estimated sales, if the sales forecast is too high, then the rate will not yield revenue requirements. Broadly speaking utilities did over-estimate sales growth in the 1970's.

Figure 1-5 illustrates the mismatch between electric utility industry forecasts in 1973 and subsequent developments. This graph also shows the 1974 predictions of Chapman and associates. Chapman represents a line of thinking about the market for electricity in the 1970's that diverged from the conventional industry view. That Chapman's view was ultimately correct meant persistent failure of utilities to earn their required cost of capital. Rates never gave "high enough" returns to stockholders. This theme will be pursued in some detail in Chapter 3. For now it is important to focus on the political repercussions of increasing cost and demand forecast over estimates.

In a word, the result was the emergence of an anti-utility political constituency. As in the days of Insull the financial troubles of utilities were blamed upon mis-management. The regulatory proceedings of the 1970's became both more frequent and more acrimonious. Various public and private agencies intervened in utility rate hearings to argue against rate increases generally, or at least not for the group they represented. A common thread in many of these arguments is that utility management was in-efficient. Rate hearings became a forum for investigating the planning process of utility management. Fuel purchase arrangements came under attack. Construction programs were criticized for being extravagant, unnecessary and wasteful.

These political battles became constant struggles. More and more of the traditional assumptions, practices and industry rules of thumb were criticized. Year in and year out opponents of utilities found more ways to obstruct utility rate requests and expansion plans. Gradually, utility opponents began to coalesce around a new strategy

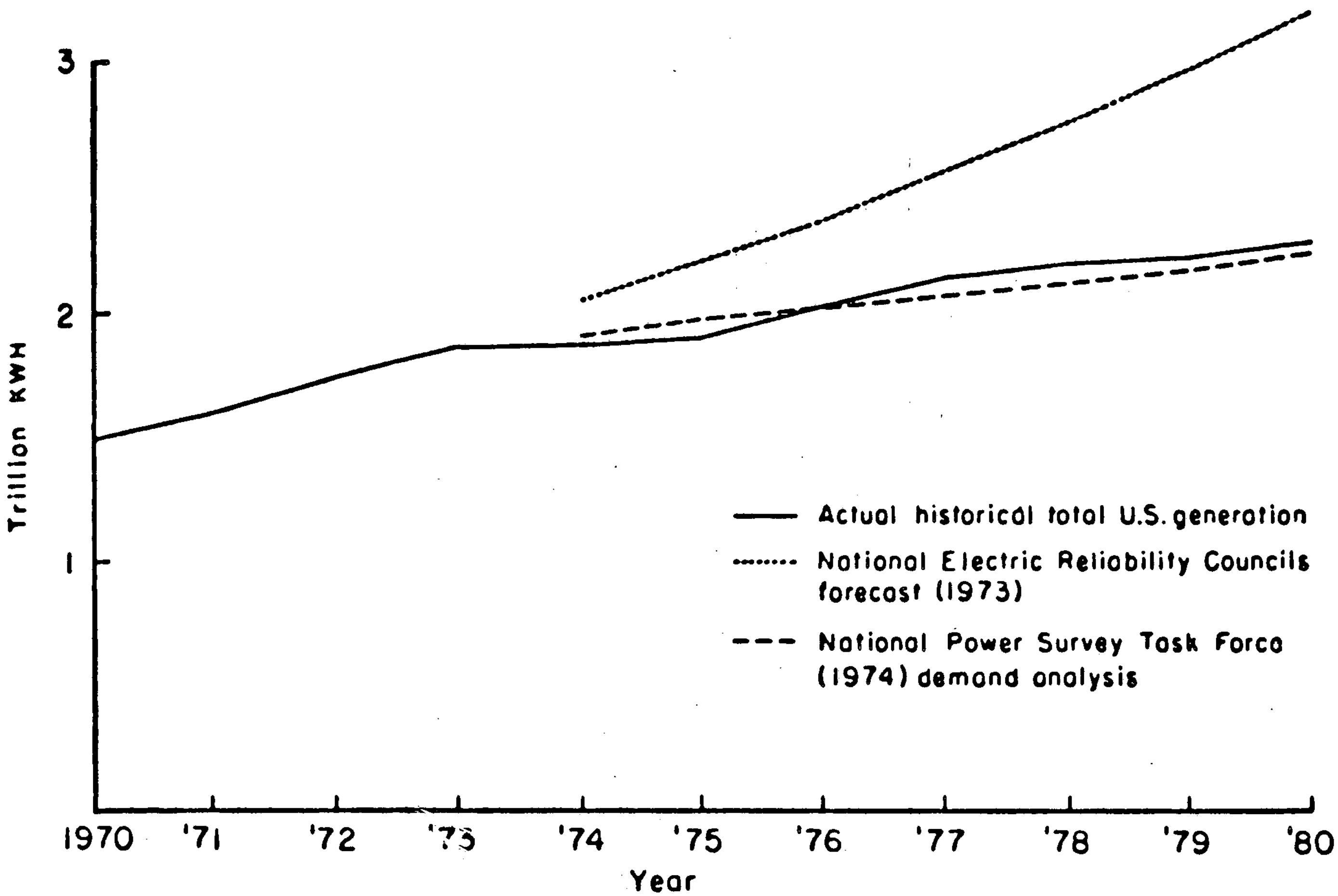

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Figure 1-5 Total U.S. electricity generation, actual and forecasts for the electric utility industry based on the assumption that scale economies for central station plants were no longer significant.

The new paradigm advocated by many opponents of the utility industry's traditional strategy was based upon small-scale supply alternatives and end-use conservation. This alternative strategy was advocated on environmental, political and economic grounds. Years of administrative hearings followed, based on abstruse engineering, financial and social cost theories. California was a principal arena for the battle over utility planning strategies. Often called "soft technology" after the phase of Amory Lovins, this collection of small scale technologies was argued to be more "appropriate" to all of society's needs than central station coal or nuclear power plants. Its proponents were quick to claim credit when several major utilities began to shift emphasis toward this new direction. David Roe, a participant/observer from the Environmental Defense Fund, summarized this experience with the following paean of praise.

> "With years of hard analysis to help them overcome previous bias, these utilities found that the alternatives were not only at hand, but that their economic advantages were substantial. Besides being cheaper, they offer greater planning flexibility, reduce financing risks, and have a near miraculous effect on earnings."
>
> New York Times, Jan. 15, 1984.

Although argued with the language of economics, the strategic debates over utility planning and regulation were in fact also political conflicts. Roe himself has been compared to V.I. Lenin by executives of the very companies he currently finds himself praising. Still, not all elements of the anti-utility coalition of the 1970's endorsed the soft technology alternative. But political opposition to business as usual foreclosed traditional choices or made them very expansive. In an industry as highly regulated as electricity, social and political objectives get translated into costs through "internalization of externalities." In particular, health, safety and environmental risks of power production that are deemed socially unacceptable generate large mitigation costs.

Among the many consequences of the upheaval in the cost structure of electricity production was the re-emergence of a debate on the organizational structure of utilities. If scale economies were no longer achievable on a meaningful level, then perhaps the "natural monopoly" status of utilities had also ended. The same economic arguments that were used to claim that conservation and small scale generation were efficient might imply that electricity generation ought to be deregulated. This theme is complicated, and difficult to assess conclusively. We will introduce it briefly now, but any really general approach must await the more theoretical discussion of Chapter 7.

1.4 Cost Structure and Vertical Integration

Why do firms choose to perform some economic functions in a particular business and not others? Industrial organization theory studies such behavior. Monopoly or oligopoly firms are a particular focus of such studies. To get a simple view of electric utilities from this perspective, it is useful to compare the traditional firm organization with the organization in similiar industries. The rationale for regulation can become clearer in this context. We will consider natural gas, petroleum, and telecommunications. In each case we can define four technological functions that must be performed. We will see that the integration of these functions within individual firms varies across industries. To highlight the role played by cost structure with respect to vertical integration we sketch the regulatory revolution in telecommunictions. The break-up of the Bell system into an unregulated AT&T plus seven regional companies may suggest ways to think about the cost revolution in electricity.

Figure 1-6 distinguishes the following four technological functions: (1) equipment vendor, (2) generation/production, (3) transmission and (4) distribution. Let us start from the bottom with distribution. It is easy to see there is a spatial economy for a single firm to operate where a physical connection must be made to each customer. Petroleum distribution can be accomplished without this. I either drive to a gas station or the fuel truck comes to my house. There is no network of pipes or wires, so many firms can compete. Gas, electricity and telephone require such a point to point network. Rather than incur the social waste of competing firms installing redundant networks, society grants a regulated franchise to one firm that exploits the natural monopoly.

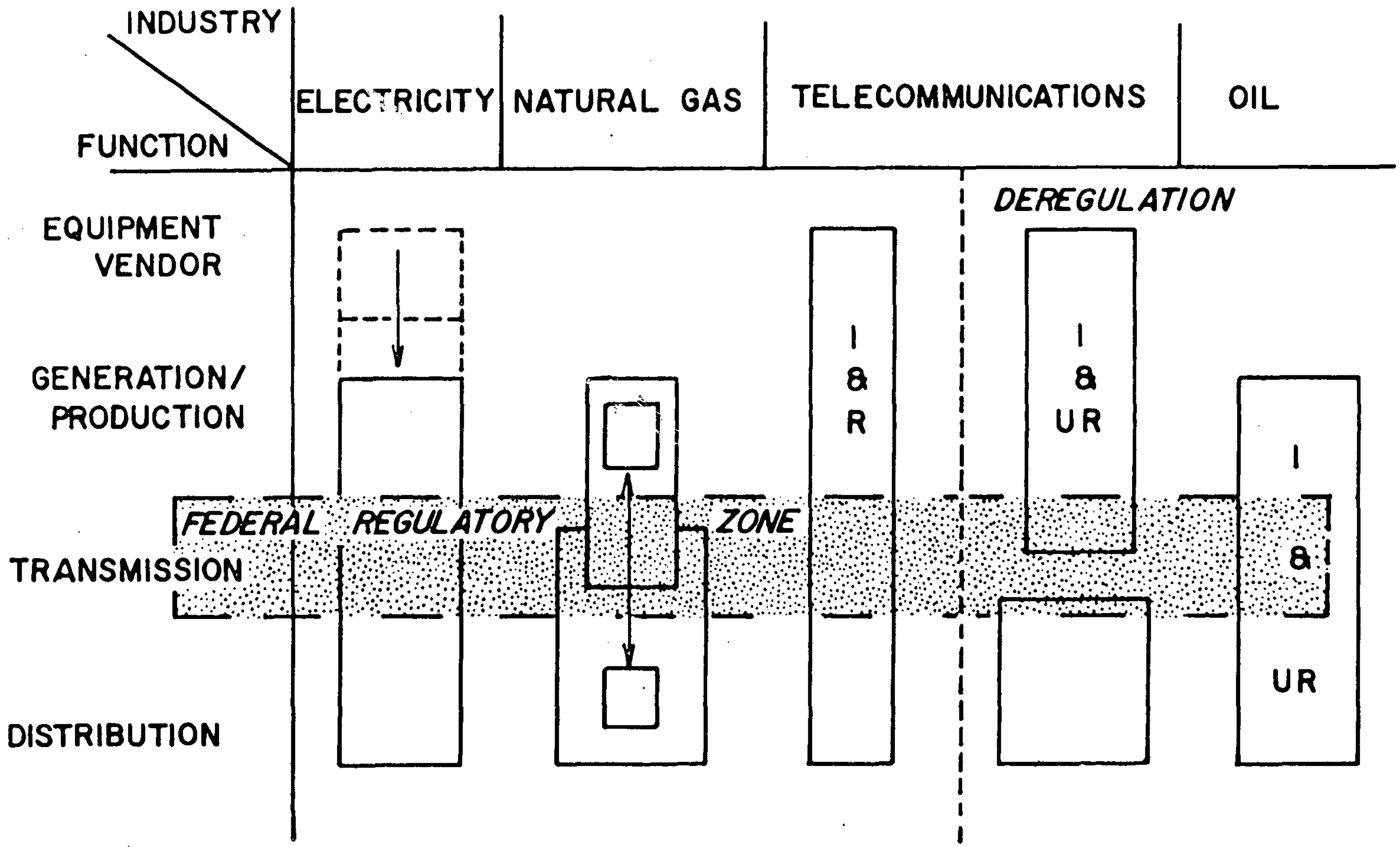

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Figure 1-6 Schematic representation of four energy production stages

Moving up to transmission, it is unusual to find a firm which only provides this function. The main exception is firms like MCI or SPRINT in the telecommunications industry. Satellite communications technology has in fact revolutionized the economics of long distance telephone transmission. This new technology is so productive that it has made room for many firms where before the spatial economies of a point-to-point network dictated a regulated monopoly. Terrestrial transmission, on the other hand, is usually integrated with production (petroleum and sometimes natural gas) or with distribution (natural gas) or with both (electricity).

The transmission function is regulated at the federal level, particularly where interstate commerce in concerned. This regulation involves not only price and rate of return, but also service conditions and dealings with other firms. Natural gas pipelines have common carrier obligations and cannot deny transmission services. Electric utilities, on the other hand, are typically not under the same obligation. Broadly speaking the reason for this difference is that firms in the natural gas industry are not fully integrated from production to distribution, whereas in electricity they are. Therefore, a multiplicity of suppliers (producers) is potentially available to a given gas distribution market. In electricity, the historical role of production scale economies is the key determinant of the vertically integrated firm type. With a relatively competitive production market, gas distribution companies could be at a serious disadvantage if pipelines were unregulated.

As we have seen in Section 1.1 transmission costs for electricity were historically more than offset by economies at the production level when large systems could be built. Insull and Westinghouse had to prove that this "high tech" strategy was efficient, to their "small scale" opponents in the industry such as Edison. In fact, electric power generation became one of the major high technology industries of the period 1890-1930 (see Hughes, 1983). There was a very close relation between equipment vendors and the utilities which purchased this equipment. Very often suppliers had to accept the securities of operating utilities as payment instead of cash. A well-known example of this was the Electric Bond and Share Corporation, which was a utility holding company owned by General Electric. Although financial interconnections between vendor and user firms can help develop new technology, there is also a potential for speculative abuse. The vendor who owns a large fraction of an operating utility's shares can obtain lucrative equipment contracts at prices above the competitive level. Such predatory practices were documented during the period which resulted in passage of the Public Utility Holding Company Act (1935).

Telecommunications was perceived until recently as an area in which scale economies of innovation were so great that a natural monoply on technology management existed. Bell Laboratories and Western Electric performed the R&D and mass-produced equipment that was standard for all aspects of the telephone business. This is no longer the case. Communication technology is merging with the computer industry in such a way that innovation can come from firms which are small. This means that the equipment vending side of American Telephone and Telegraph (AT&T) no longer deserves the special protection of a regulated monopoly status. Society's interest in innovation would be better served by the competition which now seems viable.

The distribution function of telephone companies, i.e., the local network, still has natural monopoly characteristics. This is true even on a regional basis. At some point, however, transmission over longer distances becomes competitive. In Figure 1-6, these changes in the telecommunications industry are represented as a "mitosis." The diagram represents AT&T. The integrated and regulated firm spanning all four functions splits into two new forms. The equipment vendor, production and transmission function remain integrated but are now unregulated. Distribution and some regional transmission are split off, remaining regulated.

It is important to remember that all these changes are in principal related to improving total social productivity. The new firm structures allow for more service to consumers, provided at lower total cost to society. This, at least, is the basic intention. It would appear to offer some analogies with the increasing competition and decline of scale economies in the electric utility industry. In both cases traditional sources of production economy have lost their privileged status. Small scale technology becomes competitive. In essence, however, the differences in these situations may be more important.

Electric utilities are facing competition because production economies are diminishing generally. Large scale technologies have suffered disproportionate declines. The general trend is toward increasing social cost in electricity, just the opposite from telecommunications. This difference gives a whole different flavor to the case of electricity. Under increasing cost conditions all parties are being injured one way or another. There are no absolute winners such as the new successful high technology firms in telecommunications. Instead we have what appears to be a most unusual situation in this industry, a "declining pie". The traditional growth pattern of the utility industry was an "increasing pie." Growth brought productivity gains so that the absolute size of each party's benefit grew, without respect to the relative size. Now that the total social cost of electricity production is increasing, substantial conflicts can be expected among the various parties.

It is the purpose of this book to develop a feeling for these conflicts. We will ask how they came about, what the cost structure of the industry looks like now, and what are the alternatives. All these questions will be posed in the context of specific examples based on the literature of utility planners and regulators. Chapter 2 begins with the traditional foundations of economic analysis in the industry. The exposition is based on the presentation in P.H. Jeynes Profitability and Economic Choice. Although published in 1968, this folksy textbook is something of an Old Testament. It represents the world view of utility planners in the declining cost era. We will examine the assumptions about economic analysis and the productivity of capital in the electric utility industry which are fundamental to this world view.

In Chapter 3 we outline the factors neglected in the traditional approach which could no longer be avoided as the cost structure changed. Inflation of fuel prices, capital costs and interest rates all had severe effects on the economics of electricity production. As demand growth slowed, new factors emerged in the utility planning process. Reliability, system fuel costs and the environmental effects of new power plants had to be incorporated into analysis. We will survey these complications to the planning process which were ignored, neglected, or irrelevant in the declining cost era.

Chapter 4 surveys the basic tasks of price regulation. We contrast the traditional accounting framework with the more modern concern for marginal costs. The former represents the legacy of procedures from the declining cost era. With the cost upheavals of the 1970's came a new concern for marginal costs, and how to incorporate them into the ratemaking process. We illustrate these tensions with reference to data from the 1982 General Rate Case of the Pacific Gas and Electric Company. Particular attention is also paid to inverted residential tariffs. This rate reform represents a complete reversal of the declining cost tariffs from the past.

Chapters 5 and 6 give examples of the alternative power strategy of conservation and small scale production. These chapters are designed only to illustrate what the basic economics of these options are. The larger question of where conservation and small power production fit in the long run future of the electric utility industry is deferred until Chapter 7. To appreciate these larger strategic issues we need a feeling for what makes the alternatives succeed or fail in terms of costs and policies.

It should become clear by Chapter 7 that the electric utility industry is searching for a new paradigm. The rationale for regulation must be thought out again in light of the alternative strategy. If conservation and small power are economic, is there a natural monopoly on production any more? We take up these questions with an emphasis on the instability of the current markets for electricity. We use stability concepts to characterize the properties of regulation. In this light we pose the policy problems for the future of the utility industry.

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Chapter 2

PROJECT DECISION RULES: CLASSICAL FRAMEWORK

How do planners choose projects? What rules are applied to decide when a particular investment should be undertaken? We will review the traditional approach to these questions adopted by the electric utility industry over the bulk of its history. To understand this approach it is useful to examine the assumptions implicit in it and alternative choices that might be made.

The basic problem of project evaluation in a corporate setting is to choose alternatives that make the most money. There are two principal aspects to this problem. First, the returns of a given project must be defined. There are a number of different ways to characterize project returns. We will call this first stage of the evaluation process the choice of a metric. The second stage involves relating project returns to the financial objectives of the firm. There are many different indicators of corporate financial performance. What is the appropriate measure of earnings?

In the discussion which follows we will introduce many of the concepts associated with both stages of the process. After defining these notions we will describe the logic underlying the traditional practice of electric utility planners. The exposition of this logic closely follows P.H. Jeynes' Profitability and Economic Choice. Jeynes was an accountant and engineer for Public Service Electric and Gas of Newark, New Jersey. His book, published in 1968, embodies a lifetime of experience in the engineering economics of electric power, and a concrete down-to-earth perspective on finance and accounting. It is ironic that just at the time when Jeynes book appeared, summarizing the historic conditions of electricity economics, that these conditions would change substantially.

Despite these recent changes, Jeynes codified the analytic procedures used by utility planners. As recently as 1978, the Electric Power Research Institute based the economic methodology component of its Technical Assessment Guide almost exclusively upon Jeynes. Even where modifications have been introduced by more modern writers, the revenue requirements method he expounds remains the dominant mode of utility project planning and evaluation.

To understand the roots of Jeynes approach it is necessary to take explicit account of the financial marketplace, in particular the stock market. The basic proposition Jeynes seeks to demonstrate is that maximizing shareholder profits will produce the most economically efficient outcome for consumers. He argues this thesis with many numerical examples that illustrate both a general method of analysis and a particular view about the productivity of technology in the electric utility industry. The thrust of his examples may be summarized in the following simple rules:

1. All projects must meet some minimum rate of return target.

2. These minimum return targets differ among firms and are determined by the stock market.

3. The choice between projects meeting such minimum return targets will usually favor the "bigger" or more capital intensive alternative, all other things being equal.

Following these rules will maximize shareholder profits and minimize consumer costs simultaneously.

Rules 1 and 2 involve questions of method. It is necessary to understand simple concepts of finance to give a coherent account of these rules. Section 2.1 provides such an introduction. In Section 2.2 we define various concepts of project return including those used by Jeynes. The choice criterion favored by Jeynes is defined in Section 2.3. The rule is simply "choose projects which maximize earnings per share." In practice, this rule appears to favor large scale or capital intensive projects. Why this should be so is not obvious. Indeed it will only be in Chapter 3 that counter-examples will be offered.

To lend concreteness to the discussion numerical examples can be helpful. Those which are drawn from Jeynes are typical of conditions during the declining cost period. Other data from the more recent past will tend to tell a different story. To illustrate how the Jeynes approach works in detail we outline his revenue requirements methodology in Section 2.4. This method is used to calculate a quantity called the busbar cost of electricity in Section 2.5. This application represents the most common and easiest way to compare investments in new power plants. We compare a hypothetical nuclear plant with an oil-fired plant.

Busbar cost is an important concept because it illustrates one of the fundamental flaws in the Jeynes paradigm. The basic assumption of the analysis is that the project can be characterized independent of the utility system in which it is embedded. The principal thesis of Chapter 3 is that this separation is not meaningful. Large scale projects can influence the financial and operating characteristics of the firm as a whole. Such feedback effects are ignored in Chapter 2. It is likely that they were either unimportant or basically favorable during the era Jeynes is describing. In Chapter 3 we will see that they were neither during the transition to increasing cost in the 1970's.

2.1 Introduction to Finance

Financial securities are contractual claims issued or sold by corporations or government agencies which give the purchaser the right to certain payments in the future. The two most common types of securities are stocks and bonds. In this section we will define the nature of the financial claim represented by each type and introduce methods used for valuing them.

Bonds are a specific form of loan in which the issuer receives a sum of money for a specified period of time (usually between 5 and 30 years). At the end of this period the issuer redeems the bond by returning the exact sum borrowed to the holder of the bond. In the interim the bondholder receives an annual interest payment specified at the time of issuance. This rate of interest is called the coupon rate.

Bonds differ from real property mortgages (which are also long term debt obligations) because (1) there is no principal amortization and (2) there is a liquid secondary market for bonds. Mortgages associated with real estate typically require some repayment of principal along with interest over the term of the loan. Hand calculators with the annuity feature compute the annual payment required to amortize a given debt at a specified interest rate. Bonds are essentially "interest only" mortgages with a "balloon" payment at the end of the loan equal to the entire loan principal. Bonds are also traded on security exchanges after they are issued. This is called a secondary market because the original issuer is not a party to the re-sale transactions. The corporation which issues a bond pays interest to the current holder, whoever that may be. The existence of a secondary market for bonds involves a mechanism for transferring the risk associated with a fixed coupon rate. The basic risk of owning bonds is that the market rate of interest will differ from the coupon rate.

Stocks represent a claim on the earnings of a corporation. This claim is not fixed in dollar amount, as with bonds, but varies according to the profits of the corporation. Government agencies make no profit by definition. Therefore they can only finance investment with bonds. Private corporations, on the other hand, sell ownership shares in addition to bonds as a means of financing the purchase of assets. Because earnings or profit is the residual revenue remaining after paying all operating expenses and interest, it can vary with economic conditions external to the firm. This variability, the chance for great gain or loss, makes stock (or equity) financing a more expensive form of finance than bonds. Investors must be compensated for the greater risk by earning a greater return.

Defining and measuring the return associated with owning common stock is a complicated and difficult subject. There are several widely used measures, each of which is slightly different in its focus. We will define and discuss three of these concepts without pretending to present a unified account.

Return on Equity (ROE) is a notion closely analogous to the interest rate concepts more clearly associated with bonds. A bond pays a certain percentage of its face value as a coupon interest rate to the owner. The ROE is just the earnings of the corporation divided by the total dollar sum of money paid by original purchasers for shares in that company (i.e. the total common equity). Since ROE is a fraction, it can be thought of on a per share basis. ROE is easy to compute, but may not be very meaningful if the book or equity value per share is not the same as the market price per share. If company A has a ROE of 10%, but I can buy a share of A's stock for 1/2 the book value, then I am earning 20% on my purchase. This fact motivates our second notion of return.

The Market to Book Value Ratio (MBV) measures the difference between the valuation placed on earnings by the capital markets and the original dollar cost of the assets which produce those earnings. If the underlying assets of a corporation are very productive, then the stock market will bid up the price of those shares. Electric utility stocks typically had MBV >1.5 before 1970. At times MBV>10 has been common. During the period 1973-1981, however, electric utility shares typically sold for less than book value. This meant that underlying assets were less productive than expected either by original investors, or compared to other current investments (i.e. other stocks). The essential feature of MBV is that current returns are valued relative to the expectations of the capital market as a whole. MBV measures the equilibrium process in the capital market that sets stock prices relative to original accounting costs. The ratio of market price to book value shows the deviation of these equilibrium prices from accounting cost. By comparison ROE is an accounting measure pure and simple.

The Price/Earnings Ratio (P/E) is another measure of the value associated with shareholder returns. It is the ratio of current stock price to current earnings. The P/E is like an inverse ROE adjusted for the MBV. The algebraic relations among these three concepts are given by

$$P/E = MBV \times (ROE)^{-1}$$

Most electric utilities today have a P/E in the neighborhood of 6. In its more productive period, the shares of electric utility companies sold at P/E's of 20 or more. Only high-growth, high technology companies today sell at such large P/E's.

The P/E is related to a market capitalization rate. It says what the current capital value is in relation to expected future earnings. High P/E's mean that future earnings are expected to be large, so that the current price of a claim on these is high. Underlying this evaluation of future earnings are expectations of the average future return of all equity investment in general. These expectations are embodied in a "market discount rate" (MDR). MDR is a concept widely used in equilbrium theories of financial markets, although not always under that name. MDR is very hard to measure, in part because it changes constantly in response to changing conditions. We will say no more now about MDR except that P/E values for individual stocks must be related (somehow) to MDR.

To illustrate the changing nature of interest rates, MBV, ROE and P/E we collect data for the period 1970-1980 in Table 2-1. Table 2-1 uses the inverse of P/E, called the earnings yield, as the general representative of the cost of equity capital. Comparing this to the average coupon of new AA rated utility bonds issued in the same year allows calculation of the equity risk premium. Since equity returns are riskier than bond interest, they should be higher. The average difference between the cost of equity and the cost of debt was 3.0% during this period. Table 2-1 shows substantial fluctuations in the equity risk premium. Finally, for completeness sake we include the annual GNP deflator to allow calculation of the "real" cost of debt and equity over 1970-1980. The nominal interest rate on bonds is typically 2-3% above inflation, although it has gone up to 4% and actually negative in 1974 and 1975.

Table 2-1

ELECTRIC UTILITY FINANCIAL DATA

Year	MBV	ROE	$(P/E)^{-1}$	AA Bond Yield	Δ (Stock, Bond)	GNP Deflator
1970	1.40	12.42	8.87	8.74	0.13	5.4
1971	1.42	12.00	8.45	7.70	0.75	5.1
1972	1.29	12.40	9.61	7.42	2.19	4.1
1973	1.14	11.68	10.25	7.82	2.43	5.8
1974	.81	10.79	13.32	9.47	3.85	9.7
1975	.84	11.69	13.91	9.52	4.39	9.6
1976	.94	11.95	12.71	8.66	4.05	5.2
1977	1.00	11.69	11.69	8.30	3.39	6.0
1978	.92	11.70	12.71	9.15	3.56	7.3
1979	.85	11.54	13.58	10.48	3.10	8.5
1980	.76	11.69	15.38	13.08	2.30	9.0

The interest rate on bonds also depends on their rating. Companies such as Moody's or Standard and Poor's assess the credit quality of firms and assign their bonds an ordinal ranking. The higher the bond ranking, the lower the interest rate required. This is due to the lower risk. The interest rate difference between bond ratings is called the yield spread. Figure 2-1 shows variations in bond interest rates from 1930 as a function of Moody's ratings from highest (Aaa) to the medium grade (Baa). Generally speaking ratings below Baa become so speculative, that they have a limited market.

2.2 Project Evaluation: Measuring Returns

Rational investment behavior requires that rules be developed to evaluate projects and decide which ones to accept or reject. The starting point for such procedures is the measurement of returns associated with a given project. Measuring returns can be complicated by a number of factors. At the outset we focus on the need to discount future benefits. Long-lived projects produce returns many years into the future. The nominal value of dollars generated 10 and 20 years from the time of investment are not worth as much as the dollars required to purchase assets today. The standard methods of trading these off all revolve around the notion of discounting future returns to reflect the time or opportunity cost of the delay. We will briefly examine two techniques commonly used to discount future benefit streams.

The internal rate of return (IRR) is a popular concept for measuring project returns. Formally IRR is the interest or discount rate defined by the following relation:

$$I = \sum_{i=1}^{n} R_i/(1+r)^i \ , \qquad (2\text{-}1)$$

where

I = initial investment cost

R_i = return in period i

n = number of periods

r = IRR.

IRR can only be solved for iteratively (some inexpensive calculators have this feature programmed into a few buttons). When the pattern of returns, the R_i's, includes negative terms, IRR becomes poorly defined. There are multiple roots and solutions are not

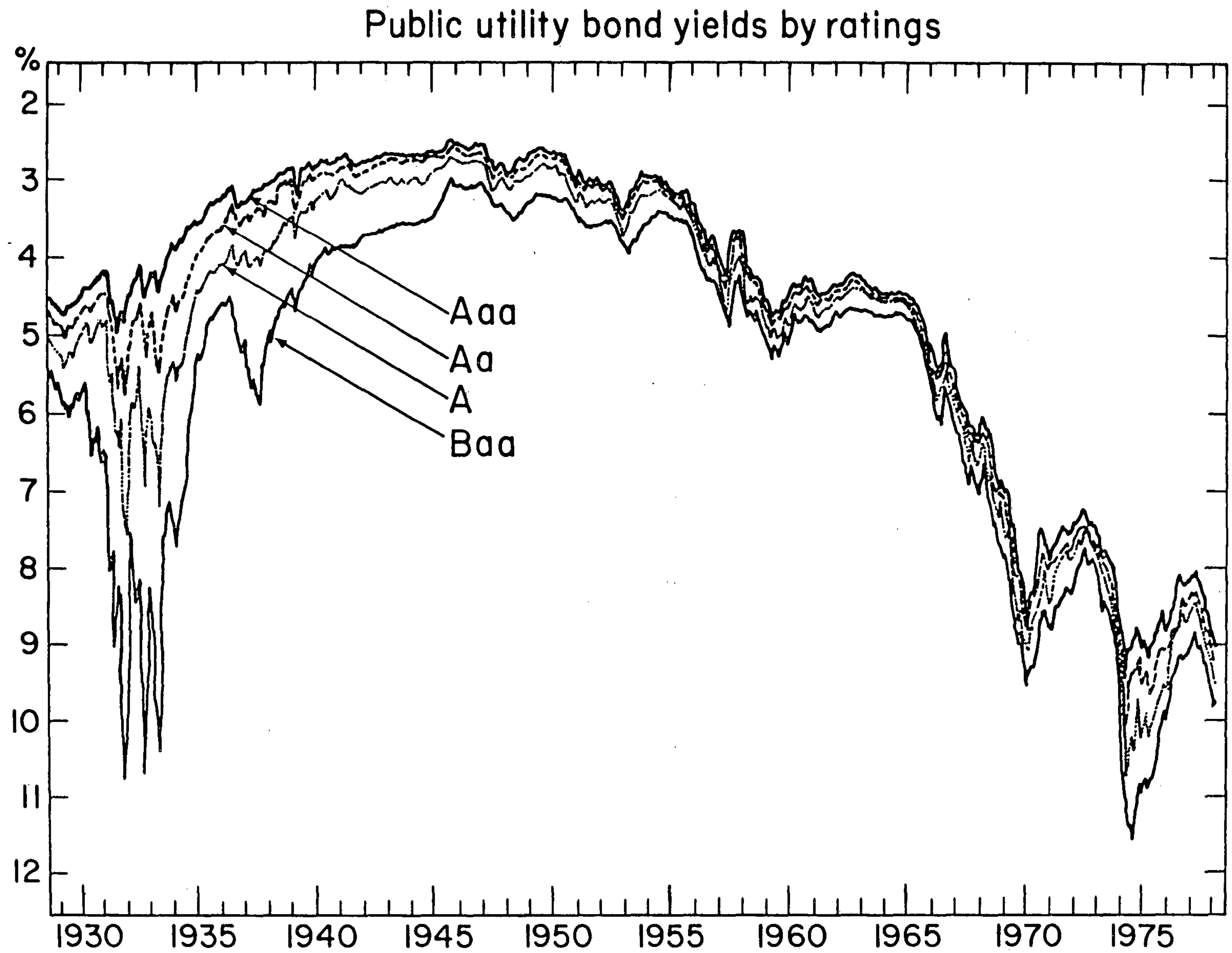

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Figure 2-1 Variations in bond interest rates from 1930 as a function of Moody's ratings unique. As an alternative the net present value (NPV) is frequently used to measure the returns of a project.

NPV is defined similarly to IRR, but the discount rate is external to the analysis, not "internal." Formally we define NPV as follows:

$$NPV = \sum_{i=1}^{n} R_i/(1+r)^i - I. \tag{2-2}$$

Algebraically when NPV = 0, r = IRR. Usually, however, r is specified in advance as some measure of the "cost of capital." Since we have seen that the "cost of capital" notion can be difficult to capture empirically, there will always be some inprecision, or at least ambiguity, about NPV estimates.

Both NPV and IRR measures depend upon forecasts of future returns R_i over many years. To avoid the tedious process of projecting revenues and expenses over each year, short-hand methods have been developed to reduce the characterization of project returns to a single year estimate. These engineering economic formulas are not explicit calculations of returns. Instead, they are estimates of project revenue requirements (RevReq) assuming minimum acceptable returns (MAR). Jeynes formalizes this approach by defining relations among these notions,

$$\text{Profit Incentive} = \text{Project Revenues} - \text{RevReq} \tag{2-3a}$$

$$\text{Project Return} = \text{Profit Incentive} + \text{MAR} \tag{2-3b}$$

The assumption underlying Eqs. (2-3a) and (2-3b) is that investor expectations of MAR can be exceeded by investing in new productive assets. Furthermore, the greatest profit incentive comes from projects which minimize revenue requirements for a fixed revenue level. The notion that this is possible is equivalent to assuming that electricity costs go down faster than rates as the system expands.

We will spend a good deal of time learning the mechanics of estimating revenue requirements. These are summarized in the handbooks such as the EPRI 1978 Technical Assessment Guide. Because MAR plays such a central role in the RevReq approach, it is important to understand what Jeynes means by it, how it is measured and what use is made of it. In what follows we will rely on his specific examples and generalize them a little.

First and foremost, MAR is a measure of stockholders expected return. The simplest formulation is given by Jeynes as

$$MAR = \frac{d_i}{P_i} + \frac{P_2 - P_1}{P_1}, \qquad (2\text{-}4)$$

where

d_i = dividend at end of period 1

and

P_i = price at the start of period i.

Eq. (2-4) says that MAR is the sum of the dividend yield and the percentage capital gain after holding the stock for one period. If we assume that the P/E is constant, then we can generalize to the stock price in year 2 as a function of earnings per share (EPS) growth rate g. Formally,

$$P_2 = (P/E)\, E_1\, (1+g) \qquad (2\text{-}5)$$

Using Eq. (2-5) in the second term of Eq. (2-4) we get a more general definition of MAR that is widely used,

$$MAR = \frac{d_i}{P_i} + g. \qquad (2\text{-}6)$$

It is easily seen that the example given in Table 2-2 from Jeynes fits into the formulation of Eq. (2-6). In particular, the dividend yield is 3.2 % and the earnings per share growth rate is approximately 5.8 %. This yields the estimate of MAR = 9.0 %

That MAR is in some sense the "market discount rate" which we alluded to earlier is illustrated in Table 2-3 from Jeynes. Here he presents a "three-period" example where the discount rate r = MAR equilibrates future earnings with present prices. As in Eq. (2-4), returns are the sum of dividends and capital gains. Formally,

$$P_1 = \frac{d_1}{1 + r} + \frac{d_2}{(1 + r)^2} + \frac{d_3}{(1 + r)^3} + \frac{P_4}{(1 + r)^3} \qquad (2\text{-}7)$$

Table 2-2

BEHAVIOR OF MAR ON COMMON EQUITY

The concensus among investors interested in purchase of the company's stock is as follows. (Optimistic and pessimistic limiting views may also be investigated and given limited weight.)

Year	Market Price (First of Year)	Earnings per Share	Dividend per Share (End of Year)
1	$75.00	$4.00	$2.40
2	79.35	4.23	2.54
3	83.95	4.48	2.69
4	88.82	4.74	2.84

Part I-A. Annual Returns to the Year 1 "Newcomer"

	His First Year	His Second Year	His Third Year
Dividend	$2.40	$2.54	$2.69
Capital gain	4.35	4.60	4.87
Total	$6.75	$7.14	$7.56
In % of $75	9.00%	9.25%	10.08%

Part I-B. Annual Returns to the Year 2 "Newcomer"

	His First Year	His Second Year
Dividend	$2.54	$2.69
Capital gain	4.60	4.87
Total	$7.14	$7.56
In % of $79.35	9.00%	9.53%

Part I-C. Annual Returns to the Year 3 "Newcomer"

	His First Year
Dividend	$2.69
Capital gain	4.87
Total	$7.56
In % of $83.95	9.00%

Part II. Average "First-Year" Return to Three Generations of "Newcomers"

1. From Part I-A	9.00%
2. From Part I-B	9.00
3. From Part I-C	9.00
Sum	27.00%

Averaged MAR on common equity = 27.00/3 = 9.00%

Table 2-3

AN ESTIMATE OF MAR

Based on a reasonable projection of past experience and the opinion of management and financial analysts, together with owners of large blocks of company stock, plus whatever other information may be available, current market opinion is believed to be as follows:

Year	Earnings (End of Year)	Dividend (End of Year)	Price/Earnings Ratio	Market Price (First of Year)
Beginning of Year 1:				
1	$1.75 (est.)	$1.30 (est.)	20 (calculated)	$35.00 (actual)
2	1.85 (est.)	1.35 (est.)	20 (est.)	37.00 (est.)
3	1.95 (est.)	1.40 (est.)	20 (est.)	39.00 (est.)
4	....	....	...	41.00 (est.)

"Newcomer's" return, Year 1:

Dividend	$1.30
Capital gain	2.00
Total	$3.30/35 = 9.43%

Year 1 Newcomer's Return, "Smoothed" Over Next Three Years:
(Try 9% and 9.5% to bracket the Year 1 observation)

Dividend/Trial MAR% = 9.0%		Dividend/Trial MAR% = 9.5%	
$1.30/(1.09) =$	$1.19	$/(1.095) =$	$1.19
$1.35/(1.09)^2 =$	1.14	$/(1.095)^2 =$	1.13
$1.40/(1.09)^3 =$	1.08	$/(1.095)^3 =$	1.07
$41.00/(1.09)^3 =$	31.33	$/(1.095)^3 =$	31.23
Total present worth	$35.07		$34.62

Present worth, discounted at 9%, almost exactly duplicates purchase price. Accordingly, MAR on common equity is currently 9%.

Jeynes shows numerically that for given assumptions about P/E, dividends, earnings and stock prices, r = 9.0 % has the property expressed in Eq. (2-7). Applying Eq. (2-7) to the same data produces a dividend yield of 3.5 % and an EPS growth rate of about 5.5 %.

It is worth examining additional properties of MAR particularly as optimism about the growth and productivity is reduced somewhat. In Table 2-4 Jeynes considers a company with slower growth and lower price earnings ratio than his previous examples. Instead of EPS growth of 5 to 5 ½ %, this company projects 2.8% . As expected, dividend yield is much higher in the lower growth case (about 7.7 %). This implies MAR = 10.5 %. This example suggests that low growth and productivity <u>increases</u> the cost of capital and conversely.

The example summarized in Table 2-5 purports to tell a similar story. Lower EPS growth expectations reduce the P/E (from 20 to 13.3). The resulting lower share prices have the effect of increasing the dividend yield from 3.0 % to 4.4 %. This increase is less than the 2 % decline in EPS growth (from 7 % to 5 %). The result is that MAR <u>falls</u> after the reduction in estimated earnings growth instead of increasing as in the previous examples.

Jeynes gives no account of these contradictions. It is not even clear that is what they should be called. We will return to this problem later on. For now it is important to see how the various project return concepts can be used in decision rules for accepting or rejecting specific projects.

2.3 <u>Project Evaluation: Decision Rules</u>

A decision rule for project evaluation requires a comparison of project returns with the financial objectives of the firm. One generic approach to this problem is the <u>hurdle rate</u> concept. Projects are evaluated using some return concept and then ranked in decreasing order. The project rates of return are then compared to some objective goal called the hurdle rate. All projects with returns greater than this hurdle rate are accepted, all others are rejected. Selecting the appropriate level for the hurdle rate is usually an exercise in estimating the incremental cost of capital. MAR has some features of a hurdle rate, because if a project cannot generate enough revenues to meet Rev.Reg. then MAR is not achieved and shareholders are injured by investment in it.

Table 2-4

ANOTHER ESTIMATE OF MAR

An estimate for another company having slower growth, greater payout ratio, smaller price/earnings ratio, and no preferred stock is:

Year	Earnings (End of Year)	Dividend (End of Year)	Price/Earnings Ratio	Market Price (First of Year)
1	$1.75 (est.)	$1.40	10.3 (calculated)	$18.00 (actual)
2	1.80 (est.)	1.40	10.0 (est.)	18.00 (est.)
3	1.85 (est.)	1.45	10.0 (est.)	18.50 (est.)
4	...	...	...	19.00 (est.)

Newcomer's return, Year 1:

Dividend	$1.40
Capital gain	None
Total	$1.40/18 = 7.78%

Year 1 Newcomer's Return "Smoothed" Over Next Three Years:

Try 8% first, based on Year 1 observation: the final conclusion is that the appropriate "smoothed" figure is 9.5%:

Trial MAR% = 8.0%		Trial MAR% = 9.0%		Trial MAR = 9.5%	
$1.40/1.08 =$	$1.30	$/(1.09) =$	$1.28	$/(1.095) =$	$1.28
$1.40/(1.08)^2 =$	1.30	$/(1.09)^2 =$	1.18	$/(1.095)^2 =$	1.17
$1.45/(1.08)^3 =$	1.15	$/(1.09)^3 =$	1.12	$/(1.095)^3 =$	1.10
$19.00/(1.08)^3 =$	15.08	$/(1.09)^3 =$	14.60	$/(1.095)^3 =$	14.47
Total Present Worth	$18.75		$18.25		$18.02

Allowance for Pressure and Selling Cost

A total allowance of $2 per share is made. Thus, the company would realize $16.00 per share.

The company's MAR on common equity, assuming $16 to be acceptable, is:

9.5% of 18.00 = $1.71 per share
1.71/16 = 10.7%

Table 2-5

AN ANALYST'S PREDICTION OF THE FUTURE OF A STOCK

Initial Estimate

Year	Earnings per Share	Price per Share	Dividends per Share
1961	$1.50	$30.00	$0.90
1962	1.60	32.00	0.96
1963	1.71	34.40	1.03
1964	1.83	36.60	1.09
1965	1.96	39.20	1.17
1966	2.10	42.00	1.23
1967	2.25	45.00	1.35
1968	2.40	48.00	1.44
1969	2.57	51.40	1.54
1970	2.74	54.80	1.64

Revised Forecast
(Something drastic happened in 1966)

Year	Earnings per Share	Price per Share	Dividends per Share
1967	2.10	28.00	1.23
1968	2.20	30.00	1.32
1969	2.31	32.00	1.39
1970	2.43	34.00	1.45

Jeynes rejects the hurdle rate approach, however, as well as any other approach based solely on a ranking of project rates of return. Instead he proposes maximizing the firm's earnings per share (EPS), for given revenue increases as the appropriate objective for investment decisions. This criterion gives different results than decision rates based only on project returns and hurdle rates. Let us illustrate the role of stock market valuation on the acceptability of projects under the Jeynes' rule.

We characterize the firms' returns before any new projects. The ROE in the initial period will be called r, and is defined as earnings (E_1) divided by equity capital (C_1).

$$r_1 = E_1/C_1 \tag{2-8}$$

Equity capital is just the number of shares N_1 times the book value per share $P_B (C_1 = N_1 P_B)$. We can express the earnings per share in this period (EPS_1) as

$$EPS_1 = E_1/N_1 = E_1 P_B/C_1. \tag{2-9}$$

A new project will have its own return p defined analogously to Eq. (2-8)

$$r_p = E_p/C_p = E_p/N_p P_p. \tag{2-10}$$

The principal difference between Eqs. (2-8) and (2-10) is that to finance the new project, the company sells shares at a price P_p that is not necessarily the same as book value. Having invested in this project, the firm now will have a new EPS. We designate the period after the project has been completed as period 2 and write the expression for EPS_2 as follows

$$EPS_2 = \frac{E_1 + E_p}{N_1 + N_p}. \tag{2-11}$$

The Jeynes rule says that the new project is acceptable only if

$$EPS_2 \geqslant EPS_1. \tag{2-12}$$

We expand Eq. (2-12) using Eqs. (2-9) and (2-11) as follows

$$\frac{E_1 P_B}{C_1} \leqslant \frac{E_1 + E_p}{\left(C_1/P_B\right) + \left(C_p/P_p\right)},$$

$$C_1(E_1+E_p) \geqslant E_1P_B\left[\left(C_1/P_B\right) + \left(C_p/P_p\right)\right],$$

$$C_1E_p \geqslant E_1C_p\left(P_B/P_p\right),$$

$$P_p/P_B \geqslant \frac{E_1C_p}{E_pC_1}. \tag{2-13}$$

Eq. (2-13) involves only MBV ($=P_p/P_B$), the pre-project return, r and the project return r_p. Substituting these definitions we get a condition on r_p, namely

$$r_p \geqslant r_1/\ \mathrm{MBV}. \tag{2-14}$$

Let us illustrate Eq. (2-14). Suppose a firm is earning 10 % on invested capital. It has three potential projects earning 9 %, 10 % and 11 % respectively. If MBV is too low, then none of these projects are acceptable. At MBV = .8 for example, a project must earn 12 % to be accepted. Conversely with MBV 1, projects earning less than 10 % can be accepted. If MBV = 1.25, then projects earning 8 % still meet the criteria.

Although Eq. (2-14) looks like a hurdle rate criterion, it is not used that way in practice. Hurdle rate rules focus on rates of return exclusively; maximizing EPS yields an ordering that depends upon the scale of projects as well as their rates of return. A small project with a high rate of return will not increase EPS as much as a larger project with a somewhat lower rate of return. All that is required is that the large project generate at least the MAR. As is clear, for instance, in Table 2-6, larger scale means "more capital intensive." That case clearly involves two alternatives which only differ by Rev.Req., and not by the amount of revenues generated. In that case, and all others considered by Jeynes, one alternative has higher capital cost and lower operating cost than the other. The Jeynes criterion will always choose this alternative.

This result bears a striking similarity to the "Averch-Johnson" thesis that regulated firms which earn more than the cost of capital have an incentive to (and in fact do) expand capital beyond its socially productive point. This argument is, in fact, stronger than what can be inferred from Jeynes. The Averch-Johnson model compares the rate of substitution between capital and variable inputs for regulated and unregulated monopolies. In the case of regulation they derive the following relation

$$\frac{-dx_2}{dx_1} < \frac{r_1}{r_2}, \tag{2-15}$$

where

x_2 = variable cost input (quantity)

x_1 = capital input (quanity)

r_1 = cost of capital

r_2 = cost (per unit) of variable.

A profit maximizing monopoly would choose inputs so that Eq. (2-15) was an exact equality.

Jeynes <u>never</u> offers an example which would satisfy Eq. (2-15). In every case, the extra capital charges, r_1dx_1, are less than the reduction in variable expenses, r_2dx_2, associated with the more capital intensive alternative. The example in Table 2-6 is typical. Increased annual capital costs, MAR, depreciation and taxes, of $107,000 in Plan (b) are more than offset by reduced "other expenses" of $150,000.

The examples we have examined so far are all highly simplified in nature. There has been very little specification of the technology underlying electricity production, transmission and distribution. The accounting treatment of fixed costs and economic analysis of variable cost have been only examined in the most sketchy manner. We will correct these deficiencies to some degree by examining the practical use of the Jeynes' decision criterion, the minimization of project revenue requirements.

Table 2-6

PROJECT EVALUATION
(Annual Revenues= $1,200,000.)

	Plan (a)	Plan (b)
1. Minimum revenue requirements	$4,000,000	$5,000,000
Capital investment	$ 240,000	$ 300,000
MAR at 6% per year	108,740	135,925
Depreciation at 2.7185%	80,000	100,000
Taxes (income and others)	350,000	200,000
All other expenses	$ 778,740	$ 735,925
2. Percentage return of project	$\frac{240{,}000 + 0.52(1{,}200{,}000 - 778{,}740)}{4{,}000{,}000} = 11.476\%$	$\frac{300{,}000 + 0.52(1{,}200{,}000 - 735{,}925)}{5{,}000{,}000} = 10.826\%$
3. Percentage return of company, post-project	$\frac{7{,}500{,}000 + 459{,}055}{100{,}000{,}000 + 4{,}000{,}000} = 7.653\%$	$\frac{7{,}500{,}000 + 541{,}319}{100{,}000{,}000 + 5{,}000{,}000} = 7.658\%$
4. Earnings per share, project	$\frac{459{,}055}{80{,}000} = \$5.738$	$\frac{541{,}319}{100{,}000} = \$5.413$
5. Earnings per share of company, post-project	$\frac{7{,}500{,}000 + 459{,}055}{2{,}500{,}000 + 80{,}000} = \$3.085$	$\frac{7{,}500{,}000 + 541{,}319}{2{,}500{,}000 + 100{,}000} = \$3.093$
6. Profit incentive per pre-project share	$\frac{459{,}055 - 240{,}000}{2{,}500{,}000} = 8.76¢$	$\frac{541{,}319 - 300{,}000}{2{,}500{,}000} = 9.65¢$

Company Finances Pre-Project
- Capital = $100,000,000
- Common Stock = 2,500,000 shares
- Book Value/Share = $40.00
- Market Price of New Shares = $50.00
- Annual Earnings = $7,500,000
- EPS = $3.00

2.4 Revenue Requirements Methodology

In this section we survey in some detail the basic methods of the revenue requirements approach. The fundamental problem in this method is to compare fixed costs and variable costs of alternate projects by reducing each to a single number which reflects different cash flows in different years. We will begin examination of fixed costs and then take up the several methods used to treat variable cost.

2.4.1 Fixed Charge Rate

Capital costs are typically annualized by using fixed charge rate (FCR). FCR is a number between 0 and 1 which expresses the sum of annual requirements for return, taxes, depreciation, and sometimes other fixed overhead costs. FCR is calculated by expressing each factor as a percentage and summing these percentages. Symbolically we can write it as

$$\text{FCR} = \text{Return} + \text{Depreciation} + \text{Taxes} + \text{Other Overhead} \qquad (2\text{-}16)$$

Up to now we have treated the return elements only as equity. In fact, firms typically finance investment with a mix of securities that include bonds and preferred stock in addition to equity. Preferred stock is a hybrid of debt and equity features. It is fixed in its percentage returns (like bonds), but its return is perpetual (i.e., never "matures") and taxable. These last two features are like common equity. Preferred stock, however, calls for dividends which must be paid before dividends or earnings accrue to common stock (thus its name "preferred"). The first step in calculating Eq. (2-16) is to expand the return component to reflect the mix of securities. This is done with the notion of weighted average cost of capital (WACC).

The main notion underlying WACC is that firms have a target capital structure which is optimal for their needs, and therefore must be reproduced by the financing of new investment. This target capital structure is a certain percentage of debt, preferred stock and common equity. WACC is nothing but the cost of each kind of capital weighted by its share of the capital. It is best illustrated by example, such as Table 2-7 from Leung and Durning representing conditions in 1977. The "Factor Costs" in Table 2-7 are comparable to Table 2-1 except for preferred stock. The two estimates are roughly

Table 2-7

WACC ESTIMATE FOR 1977

Capital Structure Components	Capital Ratio	Factor Cost	Weighted Cost
Debt	.55	.080	.044
Common Equity	.35	.114	.040
			.090

equal for 1977. Table 2-7 estimates preferred stock as less expensive than debt. The EPRI Technical Assessment Guide shows it somewhat higher.

The capital structure illustrated in Table 2-7 is typical for electric utilities since the 1930's. The amount of debt is much greater than the norm for unregulated industrial firms which typically have only 30 % debt. On the other hand, residential mortgages often constitute 80 % of the capitalization of home purchases, and commercial banks have about 95 % debt in their capitalization. There is no empirically adequate theory of why the capital structure of a given industry takes the kind of values indicated. It is only possible to observe that the amount of debt a firm or household carries increases its risk of default. Optimality is found by balancing increased debt costs against the stability of the cash flows that must pay off that debt.

Depreciation and tax costs may be treated using annuity formulas. Let us begin with depreciation. The concept of depreciation is that funds must be accrued during the lifetime of a project that will equal the original cost of the plant, and hence allow for its replacement. This can be modeled as a sinking fund S that earns a rate of return R (= WACC) on balances deposited at year end. To calculate S we add up annual unit payments plus interest as follows

$$S = \sum_{i=0}^{n-1} k^i, \text{ where } k = 1 + r. \qquad (2\text{-}17)$$

Eq. (2-17) can be expanded by the well known formula (see EPRI, p. V-19)

$$\sum_{i=1}^{n} k^i = \frac{k(1-k^n)}{1-k} \qquad (2\text{-}18)$$

We insert Eq. (2-18) into Eq. (2-17) and adjust the indices to get

$$S = \frac{(1+r)\left[1-(1+r)^{n-1}\right]}{1-(1+r)} + 1,$$

which simplifies to

$$S = \frac{(1+r)^n - 1}{r} . \qquad (2\text{-}19)$$

Since we want to accrue the sum S, we need only collect 1/s in each year, so that the sinking fund annuity for depreciation is

$$\text{Depreciation} = \frac{r}{(1+r)^n - 1} . \tag{2-20}$$

It is often useful to combine the depreciation annuity Eq. (2-20) with the return to get the capital recovery factor (CRF) as follows

$$\begin{aligned} \text{CRF} &= \frac{r}{(1+r)^n - 1} + r \\ &= \frac{r(1+r)^n}{(1+r)^n - 1} . \end{aligned} \tag{2-21}$$

The corresponding annuity for taxes on income is given by the expression

$$\text{Tax} = (\text{CRF}-\text{SL})\left(1-\frac{di}{\text{WACC}}\right)\left(\frac{t}{1-t}\right), \tag{2-22}$$

where

SL = straight-line depreciation (1/n)
d = debt fraction of capial structure
i = interest on debt, and
t = income tax rate.

Eq. (2-22) is a simplification of other expressions which involve further complexities of the tax laws. These include accelerated depreciation allowances, investment tax credits, and choice of regulatory accounting procedures. Even Eq. (2-20) neglects some factors which are used in complex depreciation and hence tax studies. For our purposes these can be suppressed. Instead we will develop a quantitative feel for these expressions by inserting numbers into Eqs. (2-21) and (2-22).

Let us use Table 2-7 as a starting point. The WACC calculated there can be turned into fixed charge rates for projects by specifying lifetimes for projects and tax rates. Table 2-8 shows examples of such calculations. We assume a combined state and federal tax rate of 52 % in these calculations. It is worth noting that for long lived projects the use of Eq. (2-22) can be avoided by using the "tax-multiplier" method applied directly to WACC. This approximation takes advantage of the fact that CRF almost equals WACC for large N. This means the depreciation annuity is small. The tax effect is treated by

Table 2-8

FIXED CHARGE RATES

Lifetime	Depreciation	CRF	Tax	FCR
5	.167	.257	.032	.289
15	.034	.124	.032	.156
30	.007	.097	.035	.132

"grossing-up" the taxable portions of the return by the factor 1/1-t. This factor yields just the gross revenue required to yield one unit of return after taxes are taken out. For t = .52, 1/1-t is 2.083. Multiplying this times the weighted cost of preferred and common equity in Table 2-7 yields an FCR = .140 compared to the value of .132 for the 30 year project in Table 2-8. For many purposes the "tax-multiplier" method is a sufficient approximation to FCR. For sensitivity calculations on FCR for the other overhead variables see Gulbrand and Leung.

2.4.2 Levelization of Variable Cost

To value a stream of changing variable costs, the technique of levelization is used. All that is involved in this method is finding a single cost constant, LC, which discounts to the same present value as the stream of variable costs VAR_i over the period of n years being studied. Formally this can be written

$$\sum_{i=1}^{n} LC/(1+r)^i = \sum_{i=1}^{n} VAR_i/(1+r)^i. \tag{2-23}$$

Graphically the concept is illustrated in Figure 2-2 for the case of increasing cost (VAR_1) and generally decreasing cost (VAR_2).

The EPRI Technical Assessment Guide of 1978 gives a formula for calculating levelized cost LC for a stream of variable costs VAR_i which escalate at a constant annual rate e. This formula is designed to compute a "levelization facter," L_f, with the property that

$$LC = L_f \times VAR_1, \tag{2-24}$$

where

VAR_1 = the variable cost in year 1.

The formula for L_f is given by

$$L_f = CRF \sum_{i=1}^{n} K^i,$$

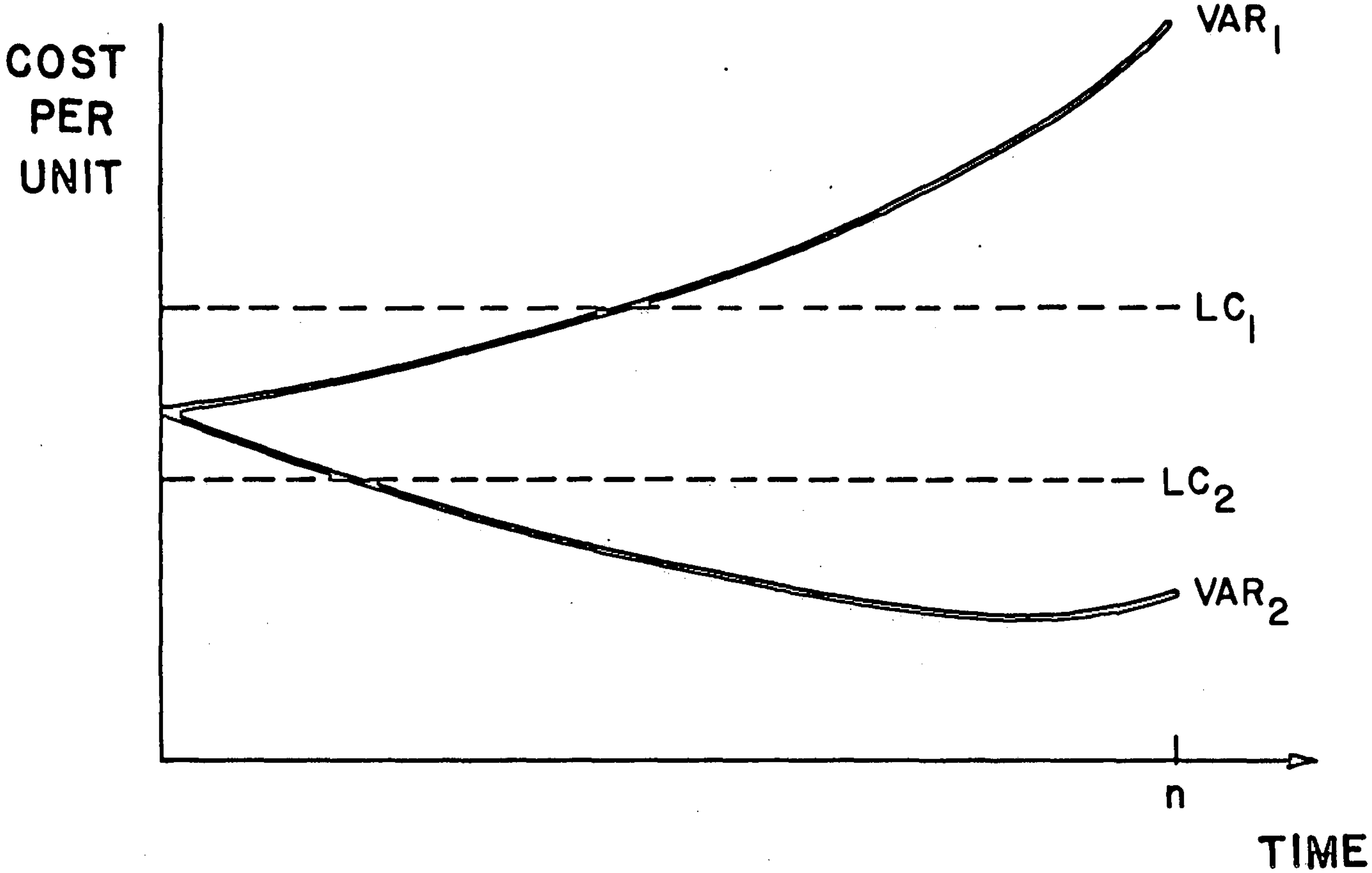

Figure 2-2 Variable costs versus time

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where

$$K = \frac{1+e}{1+r} . \tag{2-25}$$

The motivation for this formula is best seen by following the calculation of Leung and Durning for the case where escalation is not constant, but varies over the period.

Leung and Durning define levelized cost in a way which illustrates its role as a "present-value average" of the variable cost stream. In particular, they use the relation

$$LC = \frac{\sum_{i=1}^{n} VAR_i/(1+r)^{i}}{\sum_{i=1}^{n} \left(1/\ (1+r)\right)^{i}} . \tag{2-26}$$

Eq. (2-26) is equivalent to Eqs. (2-24) and (2-25) for e = constant because

$$CRF = \frac{1}{\sum_{i=1}^{n} \left(1/(1+r)\right)^{i}} . \tag{2-27}$$

Eq. (2-26) says that the total present-value of the variable cost stream divided by the sum of the future unit annuity payment also discounted to the present yields a constant value for the variable cost stream which satisfies Eq. (2-23). Indeed Eq. (2-26) is identical to Eq. (2-23) when the denominator of the right hand side is brought over to the left-hand side.

The discussion so far assumes that we are always using WACC for the discount rate r. In fact, there is something of a theoretical debate on this subject. A case can be made for a discount rate which is less than WACC when allowance is made for the tax deductability of interest on debt. Formally, this after-tax discount rate r^* is defined as

$$r^* = WACC - tdi, \tag{2-28}$$

where t, d and i are defined as in Eq. (2-22).

Modern writers on finance such as Brealey and Myers (1981), support the position that for unregulated firms Eq. (2-28) is the "proper" discount rate because it more truly represents the cost of corporate borrowing than WACC (see Brealy and Myers).

The argument against Eq. (2-28) is usually made from the regulatory perspective. When the perspective of the consumer is adopted (rather than the utility shareholder), then the tax deductability of interest payments is irrelevent if it makes no difference in revenues collected in rates. Recent changes in the tax laws (in particular the 1981 Economic Recovery Tax Act or ERTA) essentially require regulators to fix rates as if all taxes are paid at current marginal rates. This foreclosed the regulator's option of adopting either "normalization" or "flow-though" accounting treatments of tax preferences (see EPRI and Linhart, et al.). Regardless of the debate, it is useful to see how different discount rates affect levelized costs. Calculations in Table 2-9 illustrate this.

Table 2-9 shows that lower discount rates increase levelized variable cost. The net effect of this is to improve the relative attractiveness of projects for which capital substitutes for variable costs. Because Eq. (2-28) is not typically used in electric power investment decision making, but the higher valued WACC is, it has been argued that no pro-capital Averch-Johnson bias exists in the industry. Corey makes this argument in his survey of utility practices in 1977. Finally, it is worth noting that Corey, who was a prominent executive with Commonwealth Edison of Chicago, makes the strongest economic argument for the use of Eq. (2-28). Referring to this rate as "the rate of disadvantage," he argues that what make its use desirable is that the present value of future revenue requirements discounted this way is independent of regulatory or bookkeeping practices (p. 262). This means that truly "economic" choices can be made this way without the distortions and constraints of particular rate-making practices. This is an interesting claim, that would be more persuasive if it were demonstrated.

2.5 Examples: Busbar Cost of New Power Plants

To illustrate the revenue requirements method we will compare two alternative projects: a nuclear plant and an oil burning plant. In all likelihood neither alternative would be seriously considered by any utility today, but the comparison can be instructive. The quantity we will calculate is the busbar cost per kilowatt-hour (kWh) from each alternative. Busbar cost is the unit revenue requirement for a kilowatt-hour

Table 2-9

LEVELIZATION FACTORS

L_f FOR N = 30

	Discount Rate		
Escalation Rate	(A) WACC = .09	(B) WACC - tdi = .069	(B)/(A)
7 %	2.217	2.418	1.091
10 %	3.368	3.832	1.139

delivered from the generating plant to the transmission network (called the busbar). This figure ignores a number of complications in the total cost of electricity, but is a useful first approximation.

The basic logic of the busbar cost calculation is illustrated by the following relation

$$\text{Busbar Cost} = \frac{\text{Capital Cost/ kW x FCR}}{\text{Annual Production}} + \text{Levelized Fuel Cost} \qquad (2\text{-}29)$$

In Table 2-10 we list the assumptions used to make the comparison between nuclear and oil power plants. The first step is to calculate the fixed charge rate FCR. Using a total tax rate of 52.5 % and the tax multiplier method, FCR and WACC, the weighted average cost of capital are shown in Table 2-11. The data in Tables 2-10 and 2-11 are sufficient to compute the levelized fixed charges for each alternative. These are given by

$$\text{Fixed Charges}_N = \frac{\$2{,}000 \times .227}{5{,}000}$$

$$= 90.8 \text{ mills/ kWh}$$

$$\text{Fixed Charges}_O = 45.4 \text{ mills/ kWh.}$$

The magnitude of these costs depends upon the expected annual production (assumed to be 5,000/ kWh per kW). The Table 2-10 assumption is equivalent to assuming that the plants run 57 % of the hours of the year. Such a number is called the capacity factor.

Levelized fuel costs are calculated using Eqs. (2-24) and (2-25). Table 2-12 summarizes these calculations.

These costs will vary with assumptions about capacity factors, fuel escalation rates, appropriate discount rates (as in Table 2-9), etc. The example illustrates the basic trade-off between fixed and variable costs which is fundamental to electric utility project evaluations. In this example, the extra fixed costs of the nuclear plant more than offset the fuel costs of the oil plant. Based on these assumptions, it is economic to substitute capital for fuel.

Table 2-10

ASSUMPTIONS FOR BUSBAR COST COMPARISON

1. Capital Costs

Nuclear	= \$2,000/ kW	
Oil	= \$1,000/ kW	

2. Fuel Costs

Nuclear: Year 1	= 20 mills/ kWh	
	Escalation Rate = 2 %/ year	
Oil: Year 1	= 50 mills/ kWh	
	Escalation Rate = 7 %/ year	

3. Annual Production = 5000 kWh/kW year

4. Financing Costs

Debt	= 50 % of capital, interest rate = 3%
Preferred Stock	= 10 % of capital, interest rate = 13 %
Common Equity	= 40 % of capital, cost = 16 %

5. Economic Lifetime = 30 years

Table 2-11

CALCULATION OF FCR AND WACC

Component	Capital Ratio	Cost	Weighted Cost	Taxable Cost
Debt	.50	.13	.065	.065
Preferred Stock	.10	.13	.013	.027
Common Equity	.40	.16	.064	.135
			WACC = .142	FCR = .227

Table 2-12

LEVELIZED FUEL COSTS

	Escalation Rate	Discount Rate	K = lte/ltr	$\frac{K(1-K^N)}{1-K}$
N	2 %	14.2 %	.893	8.065
O	7 %	14.2 %	.936	12.61

	CRF	L_f	Levelized Cost (mills/ kWh)
N	.144	1.16	23
O	.144	1.81	91

Busbar cost is then the sum of fixed costs and fuel costs, i.e.,

$$\text{Busbar}_N = 90.8 + 23 = 113.8 \text{ mills/ kWh,}$$

and

$$\text{Busbar}_O = 45.4 + 91 = 136.4 \text{ mills/ kWh.}$$

Bibliographical Note

There are many standard references on project evaluation from an engineering economics perspective. Modern examples include Bussey (1979). Application of this perspective to electric power is developed most completely by Jeynes (1968) and embodied in handbooks such as EPRI (1978). Lucid brief accounts with interesting examples are given in Gulbrand and Leung (1975) and Leung and Durning (1978). Among the controversial aspects of these methods are the supposed capital bias discussed by Averch and Johnson (1962) and controversies over the "correct" discount rate to be used. Corey (1982) gives a useful discussion of theory and practice on this other issue. Modern texts on corporate finance such as Brealey and Myers (1981) emphasize different procedures than the classical methods used by utility planners. Selected financial data on electric utilities can be found in Moody's (1983), NERA (1981) and Bingham and Schane (1982).

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Chapter 3

MODERN COMPLICATIONS OF THE PROJECT DECISION PROCESS

This chapter illustrates the difficulties that arose in the 1970's for utility planners. Dimensions of the project evaluation process which were suppressed or neglected in the classical framework became inescapable. Capital costs escalated and project lead times became substantial. These factors had to be incorporated into the evaluation framework. At the same time as the fundamental cost conditions for producing electricity were changing, changes in the financial markets began to have a negative effect on utilities. The systems engineering aspects of generation capacity expansion also became more complex. Issues related to reserve margins and bulk power reliability became controversial, and induced more sophisticated modeling and analysis. As the number of factors requiring analysis increased, large scale computer models were introduced to account for the complexity. Even these were inadequate to deal with issues that could not be easily monetized, such as environmental quality or financial risks. Thus the paradigm bequeathed by Jeynes broke down during the economic changes of the 1970's.

The result of the price shocks of the 1970's and the slow adjustment made to them was a substantial mismatch of supply and demand. The evidence of this mismatch is shown in Table 3-1 which indicates the trend in orders for nuclear plants and the cancellation of both coal and nuclear plants from 1972 to 1982. These figures are incomplete and the data are subject to some interpretation, but the trend is clear. Many projects which seemed justified under the Jeynes' decision rule, and cost assumptions before 1974 were not economically viable in the long run. Many of these cancellations imposed large losses. Some projects involved billions of dollars in costs which were ultimately unproductive as the plants were abandoned before completion.

The ultimate impact of these losses has not been sorted out as yet, but their political import is somewhat clearer. Utilities have been accused of mismanagement and have been penalized financially by regulators. Such penalties have not yet brought any company to the point of bankruptcy, but at least the prospect of such outcomes have been raised.

Table 3-1

ORDERS AND CANCELLATIONS OF NEW BASELOAD POWER PLANTS

	Orders for Nuclear Plants	Nuclear Cancellations	Coal Cancellations
1972	38	7	
1973	41	0	
1974	28	7	19
1975	4	13	3
1976	3	1	8
1977	4	10	
1978	2	14	2
1979	0	8	4
1980	0	16	2
1981	0	6	6
1982	0	18	

(Source: EIA, 1983a and 1983b.)

A particularly stark situation of this kind involves the Shoreham project of the Long Island Lighting Company (LILCO). Political conflict over safety issues associated with the project and enormous increases in capital cost have undermined the viability of this plant. Yet regulators never seriously questioned the continuation of the project until 1983. The chairman of the New York Public Service Commission from 1974 to 1977 was Alfred E. Kahn, who was, among other things, author of an authoritative text on public utility regulation published in 1971. He commented recently on the regulatory review the Shoreham project received during his tenure.

> "We're all victims of creeping incrementalism. At any given time, it was impossible, on the basis of what we knew, to say we shouldn't go ahead ...... Each time, appalled at what had happened before, it was still possible for us to justify continuing."
>
> "Nuclear Power Plant Threatens Utility's Future"
> Los Angeles Times, March 4, 1984

Yet despite the support of these regulatory reviews, the project may never operate, an outcome that was wholly unanticipated. How could this happen? What went wrong? In this chapter we will try to answer these questions at a general level, and from the perspective of the planner. We will identify those factors which were neglected in the planning paradigm represented by Jeynes, but became important in the 1970's.

In Section 3.1 the evidence on increases in power plant construction cost is reviewed. The increasing amount of time required to build new plants is also illustrated. Section 3.2 introduces a simple model of the economics of premature installation, i.e., the construction of facilities before they are needed to serve demand. Arguments of this type were used to rationalize large scale construction projects in advance of demand growth. Section 3.3 discusses the treatment of financing costs for uncompleted construction projects. Regulators tend to impose delays on the recovery of those costs. This had important effects on the valuation of electric utility stocks. More complex theories of the cost of equity capital were required to explain the stock market of the 1970's. These are discussed in Section 3.4 in the context of electric utility cost conditions. Section 3.5 explains the role of reserve margins and reliability in the project evaluation process. In Section 3.6 the complicated capacity expansion models are surveyed. Section 3.7 explores the particularly difficult case in which non-monetary factors are incorporated into the analysis.

3.1 Moving Targets: Capital Cost Escalation

While it is now clear that fuel costs can change dramatically over time, it became equally clear in the 1970's that capital costs could also change drastically. The direction of change in the 1970's and beyond has been increases in cost. The sources of these increases involved the internalization of environmental, health and safety costs associated with power production. Labor productivity, management and regulatory factors also played a role.

The problem for project planners is that capital cost escalation is not as easily accommodated to the revenue requirements methodology as changes in variable cost. The basic difficulty has to do with elongation of the planning horizon as construction lead-times for power plants increase. It not only became more expensive to build new generation facilities in the 1970's, it also took longer and longer. As lead times increased, it became more difficult to determine exactly when a project would be completed, or how much it would cost. Indeed lead-time and cost are intimately related since many of the construction costs of new plants are time-related.

To illustrate the magnitude of these effects it is useful to collect some of the data on lead times and costs. For the case of nuclear plants, the increase in construction duration is illustrated in Figure 3-1. This shows roughly a doubling (from 5 to 10 years) in the time from the utility's ordering a Nuclear Steam Supply System (NSSS) from a reactor vendor, and the commercial operation of the plant. Capital cost data for coal and nuclear plants are collected in Table 3-2. These costs represent the nominal dollar accounting cost of the plants that correspond to a rate base valuation, that is, when the plant's costs are incorporated into rates. The Table 3-2 figures represent on a $/kw basis, the investment cost. Figure 3-2 shows a scatter plot for nuclear plant construction costs. In a revenue requirements study this cost is the term which is multiplied by FCR to produce annual fixed charges. Table 3-2 also includes data on the average annual change in construction cost factors for power plants. The Handy-Whitman Index is a specialized cost index designed to measure changes in labor and materials prices that is analogous to broader price indices such as the CPI, the GNP deflater or the Producer

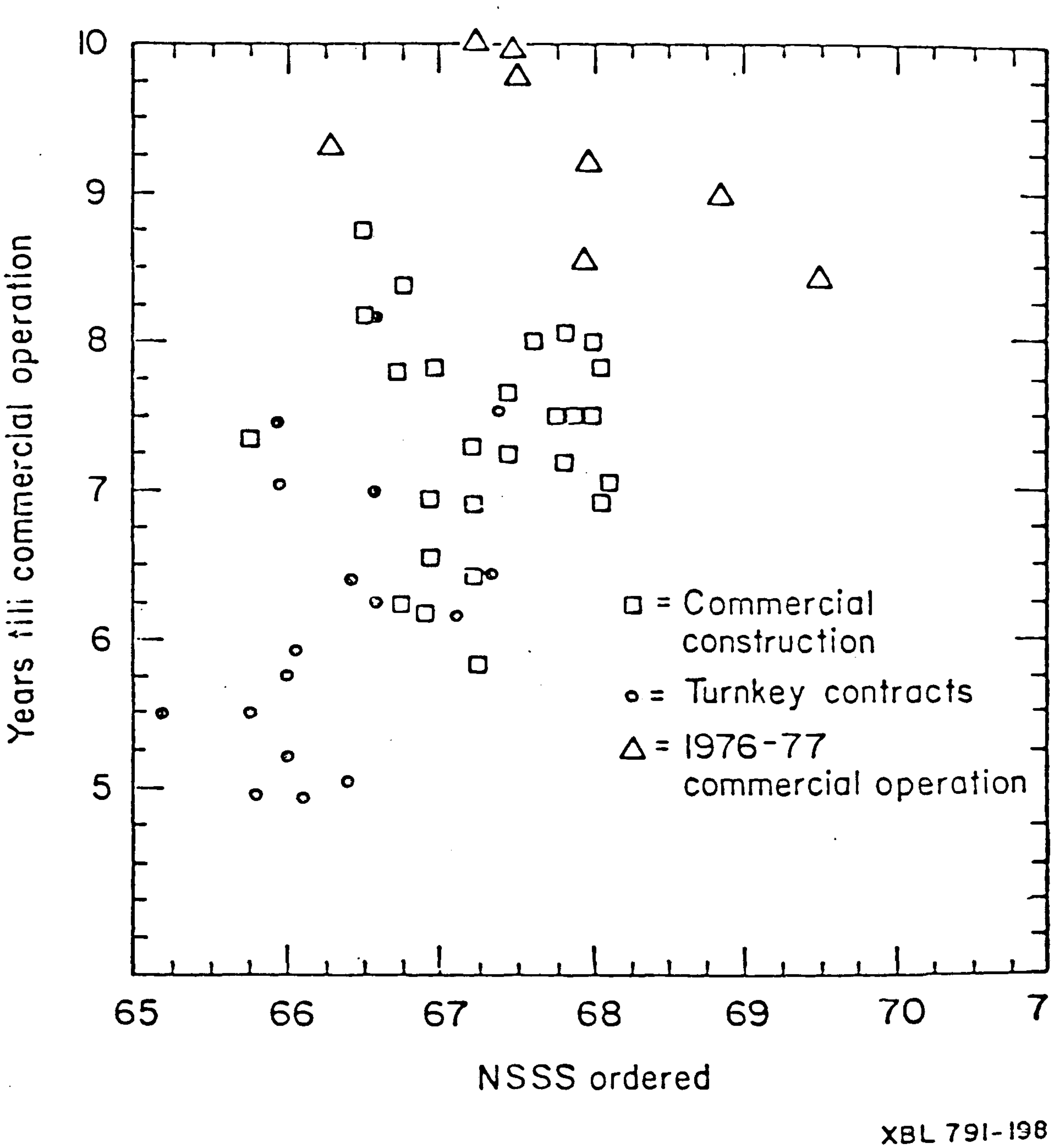


Figure 3-1 **Nuclear plant construction time**

Table 3-2

CAPITAL COST ESCALATION: DATA

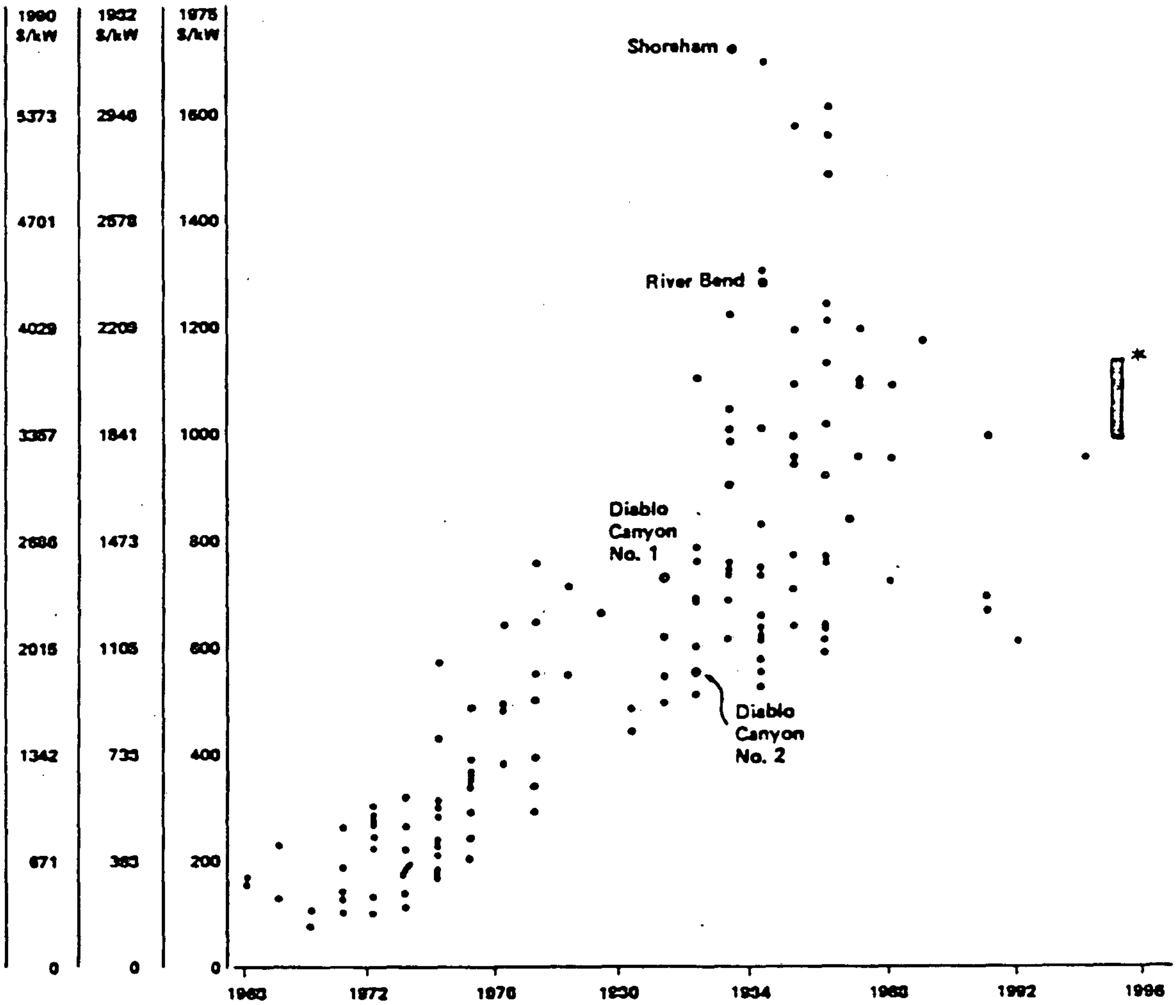
In Service Date	Capital Cost ($/kw) Coal	Capital Cost ($/kw) Nuclear	Change in Handy-Whitman Index of Construction Co. Coal	Change in Handy-Whitman Index of Construction Co. Nuclear
1967[a]	185	170	3.1	3.6
			3.8	4.4
			6.3	5.8
			7.2	8.1
1971[b]	162	172	11.1	10.1
			3.7	4.4
			7.5	6.4
			25.1	17.8
1975			9.0	10.8
			6.9	7.9
			6.3	5.9
1978[c]	580	870	10.8	9.3

a) Federal Power Commission, National Power Survey, Part II, Table 1A (October, 1964) p. 178.

b) C. Komanoff, Power Plant Cost Escalation, KEA, (1981), Table 10, p 228 deflated to 1971 $ using Handy-Whitman Index.

c) Generation Task Force, New England Power Planning, 1978. (same as (b)).

Nuclear Plant Construction Costs: Cost per kW



* Range of projected costs for addtional new plants in 1996, based on Projected Cost of Electricity from Nuclear and Coal-Fired Power Plants, EIA, August 1982.

Includes all costs (both construction expenditures and accumulated AFUDC, where applicable).

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Figure 3-2 Scatter plot for nuclear plant construction costs

Price Index. It is useful to compare changes in the construction cost index to changes in plant cost to separate the components of cost escalation. This is done in Table 3-3 for the 1971 and 1978 plant cost estimates.

In Table 3-3 power plant cost escalation is separated into that part which reflects increases in unit labor and materials cost (item B) and an unexplained residual (item C). The residual or real cost increase is generally thought to reflect an increased complexity of plant design for environmental and safety controls. That is, extra labor and material requirements for systems not required in earlier plants (for example, flue gas de-sulfurization in coal plants and back-up safety systems in nuclear plants). In fact, there are additional complexities in the data, in particular, scale economics at the plant level. Over the period 1967-1978, the size of new generating units increased substantially (roughly by a factor of 3). The unit capital costs for a plant are generally observed to decline as size increases, all other things being equal. This factor should offset the cost increases attributable to additional environmental and safety controls to some degree. Table 3-2 suggests that between 1967 and 1971 scale economies for nuclear plants were substantial (unit size roughly doubled in that period). On the other hand, coal plants also increased in capacity by a factor of two, but unit costs almost perfectly reflect changes in the Handy-Whitman Index alone. This means that there were no scale economies for coal plants, or that they were washed out by changes in design. Detailed study of this data is by no means complete. Komanoff's book represents one attempt to untangle the various factors.

One principal conclusion that emerges from these data is that the static view of project alternatives assumed implicitly in the revenue requirements methodology is not appropriate to periods of rapid change in unit capital costs. This inappropriateness is most clear when explicit account must be taken of the time dimension. Jeynes' view of project evaluation is one in which investment occurs "overnight." Time is never a fundamental element. To broaden our perspective it is necessary to consider explicitly how the time dimension complicates the problem of project evaluation. The issues involved in this exercise include scale economies, inflation, cost escalation, and lead time.

Table 3-3

EXPLAINED AND UNEXPLAINED COST ESCALATION

	Coal	Nuclear
A. 1978/1971 Costs	3.580	5.058
B. Handy-Whitman Index 1978/1971	2.126	1.994
C. Real Escalation = (A/B)	1.684	2.537
D. Average Real Escalation per year	6.7%	12.3%

3.2 Time Dynamics: The Economics of Premature Installation

Leung and Durning provide an example of project evaluation involving the temporal dimension which neatly illustrates how quickly decision rules can break down. The example involves the installation of a transformer serving a residential housing development. The problem involves choosing between a 37 KVA transformer which would be adequate for the current demand and a 50 KVA transformer that is projected to be required in 10 years. The capital cost of the smaller unit is assumed to be $60,000 and the larger unit is assumed to cost $90,000. If the smaller unit is chosen today, it must be replaced with the larger unit at an escalated cost of $160,000. Each unit has a salvage value at the end of ten years. This is $15,000 for the smaller unit, and $30,000 for the larger unit installed in year 10. The alternatives are summarized in Table 3-4.

Following Leung and Durning we calculate the present value of all future revenue requirements for alternatives (a) and (b). We assume that there is no difference in operations and maintenance cost (O&M) so that we can ignore this cost. The analysis concerns only the fixed costs. Let us first calculate the fixed charge rates appropriate to 10 year investments (alternative (a) and 20 year investments). These are given in Table 3-5 where the depreciation and tax annuities are calculated using Eqs. (2-20) and (2-22). Additional allowances are made for property taxes (ad valorem), insurance and administrative and general expenses. We call these other overheads.

We now calculate the present value revenue requirement for Alternative (a). The first step is to discount the ten year stream of fixed charges on the smaller transformer,

$$\text{PV Fixed Charges} = \sum_{i=1}^{10} \frac{\text{FCR}_{10} \times \text{Capital Cost}_1}{(1+d)^i} . \qquad (3\text{-}1)$$

Recalling Eq. (2-22) we can re-write this as the simple ratio of FCR/CRF because CRF is the inverse of the sum of the present worth factors $1/(1+d)^i$, so

$$\text{PV Fixed Charges} = \frac{\text{FCR}_{10}}{\text{CRF}_{10}} \times \text{Capital Cost},$$

$$= \frac{.2197}{.1558} \times \$6 \times 10^4 \qquad (3\text{-}2)$$

Table 3-4

TRANSFORMER DECISION

Costs and Values

	Year 1	Year 10	Year 20
i) 50 KVA	$9 x 10^4	$16 x 10^4	$3 x 10^4 salvage
ii) 37 KVA	$6 x 10^4	$1.5 x 10^4 salvage	

Installation Schedule

Alternative (a)	Install ii)	Replace ii) with i)
(b)	Install i)	

Table 3-5

FIXED CHARGE RATES (PERCENT)

	10 Year Life	20 Year Life
Return	9.00	9.00
Depreciation	6.58	1.95
Income Tax	2.98	3.18
Other Overheads	3.41	3.41
	21.97%	17.54%

$$= 1.409 \times \$6 \times 10^4$$

$$= \$8.456 \times 10^4 .$$

Next we subtract the salvage value in year 10, which must be discounted back to year 1,

$$\text{PV Salvage Value} = 1/(1+d)^{10}\ (\$1.5 \times 10^4),$$

$$= .4224 \times (\$1.5 \times 10^4) \qquad (3\text{-}3)$$

$$= \$.634 \times 10^4.$$

The third step is to calculate the present value of the fixed charges on the replacement transformer. This is analogous to Eqs. (3-1) and (3-2), but involves the extra step of discounting from year 10 back to year 1. In particular

$$\text{PV Fixed Charges-Replacement} = \frac{1}{(1+d)^{10}} \left[\frac{FCR_{10}}{CRF_{10}} \right] \text{Capital Cost}_{10}$$

$$= .4224 \times 1.409 \times \$16 \times 10^4$$

$$= \$9.523 \times 10^4 \qquad (3\text{-}4)$$

The salvage value of the replacement transformer must also be discounted back to year 1, as follows

$$\text{PV Salvage Value-Replacement} = \frac{1}{(1+d)^{20}} \times \$3 \times 10^4$$

$$= .1784 \times \$3 \times 10^4$$

$$= \$.535 \times 10^4 \qquad (3\text{-}5)$$

Finally, then the present value revenue requirement of alternative (a) is the sum of the fixed charges minus the salvage values. In our notation this can be written

(3-2)-(3-3)+(3-4)-(3-5).

$$\text{PV Alternative (a)} = \$16.81 \times 10^4. \tag{3-6}$$

Alternative (b) is quite simple by comparison, we use the analogue of Eq. (3-1) for projects with a 20 year life. This is easily calculated as

$$\text{PV Alternative (b)} = \frac{FCR_{20}}{CRF_{20}} \times \$9 \times 10^4 \tag{3-7}$$

$$= \frac{.1754}{.1091} \times \$9 \times 10^4$$

$$= 1.606 \times \$9 \times 10^4$$

$$= \$14.45 \times 10^4$$

The conclusion from this exercise is that premature installation of the larger transformer saves money in the long run. This conclusion is interesting because it represents planning "rule of thumb" which has characterized the utility industry for many years. The basic business strategy embodied in this example is that building "ahead of the load" is economic and profitable. To understand how this conclusion emerges and what factors produce the result, we shall generalize and abstract this example. Before doing this, however, it is necessary to observe that the projected growth in demand is fundamental to this example. If demand never grew to the 50 KVA level, it would always be preferable to install the smaller unit. The present value revenue requirement in such a case is only $\$9.64 \times 10^4$ ($= 1.606 \times \$6 \times 10^4$).

To simplify our analysis of the general case we drop the consideration of salvage values. Because of discounting, these are small (5-7%) in comparison to original installed cost. Now we introduce a little notation. Let us call the ratio of FCR to CRF for a given discount rate d and lifetime i, Z_i, that is

$$Z_i = FCR_{i,d}/CRF_{i,d}.$$

We will use the index n for the long lived asset and j for the shorter lifetime. To characterize the cost of big and small units we define

S = \$/cap of small unit capacity

s = # of units of capacity costing S

B = \$/cap of large unit capacity

b = # of units of capacity costing B.

We now define Alternatives (a) and (b) in this notation as

$$\text{(a) } Z_j S x s + \frac{1}{(1+d)^j} Z_j \; B(1+e)^j \; x \; b$$

$$\text{(b) } Z_n \; B \; x \; b \tag{3-8}$$

We have introduced cost escalation in the large unit by using a growth rate e in Alternative (a). We would like to know when (b) $<$ (a). This occurs when the following inequality is satisfied

$$Z_n B \; x \; b < Z_j \; S \; x \; s + \left(\frac{1+e}{1+d}\right)^j \; Z_j \; B \; x \; b. \tag{3-9}$$

Eq. (37) can be re-written as

$$\frac{B \; x \; b}{S \; x \; s} \left[Z_n - \left(\frac{(1+e)}{(1+d)}\right)^j \quad Z_j \right] < Z_j. \tag{3-10}$$

The first factor on the left hand side of Eq. (3-10) can be expressed using the definition of scale economy. The total cost of capacity of size x can be expressed as

$$c(x) = kx^{1-a}, \text{ for } k = \text{constant and } a < 1. \tag{3-11}$$

This relation indicates that costs increase less than linearly with capacity. For a 0 there are dis-economies of scale. Using Eq. (3-11) we can re-write Eq. (3-10) as

$$(b/s)^{1-a} \left[Z_n - \left(\frac{1+e}{1+d}\right)^j Z_j \right] < Z_j. \tag{3-12}$$

Eq. (3-12) shows that both scale economies and cost escalation tend to favor premature installation in the model. What is more interesting empirically is that even with dis-economies of scale, premature installation can still be favored if there is enough cost escalation. The transformer example is actually such a combination. The data show scale dis-economies. The large transformer costs 11% more per unit than the smaller one ($1800/kVa vs $1620/kVa). Therefore the parameter a must be less than zero. It is roughly -0.35, so that only the effect of the parameter e allows Eq. (3-12) to be satisfied in this case. (Note that $1+e = (160{,}000/90{,}000)^{1/10}$ implies that e = .06).

There is considerable historical significance to this illustration. Broadly speaking the period of scale economies in power generation ended as the era of cost escalation began. A decision rule such as Eq. (3-12) tends to confuse these two phenomena. This confusion is important because, in the large, cost escalation will end up altering the demand conditions underlying the derivation of Eq. (3-12). The rule favoring premature installation of over-sized capacity only works if the need for the larger capacity ultimately materializes. If it does not, or is substantially delayed ($j \rightarrow n$), then the logic of early installation breaks down. Yet cost escalation, if it is broad and pervasive enough, will reduce future demand through price elasticity.

This is approximately what happened in the generation segment of the electric utility industry. The capital cost escalation indicated in Table 3-2 was paralleled by increases in fuel costs. Together these effects dominated all other costs in the price of electricity and had the effect of dampening demand considerably. Planning forecasts of future demand did not adapt quickly to these changes (see Figure 3-3). Therefore rules of thumb such as Eq. (3-12) were not abandoned even though they were no longer appropriate. By the early 1980's, however, it became increasingly clear that fundamental changes in industry conditions required new decision criteria. We will explore these in some detail later. First it is necessary to examine the consequences of the substantial inertia of adjustment from a regime of scale economies and declining cost to one of cost increases.

As we have seen, one of the main features of changing power plant construction conditions in the 1970's was the increasing length of the construction period. We now turn to an explicit treatment of the time related costs imposed by this and their effects upon utility customers and shareholders.

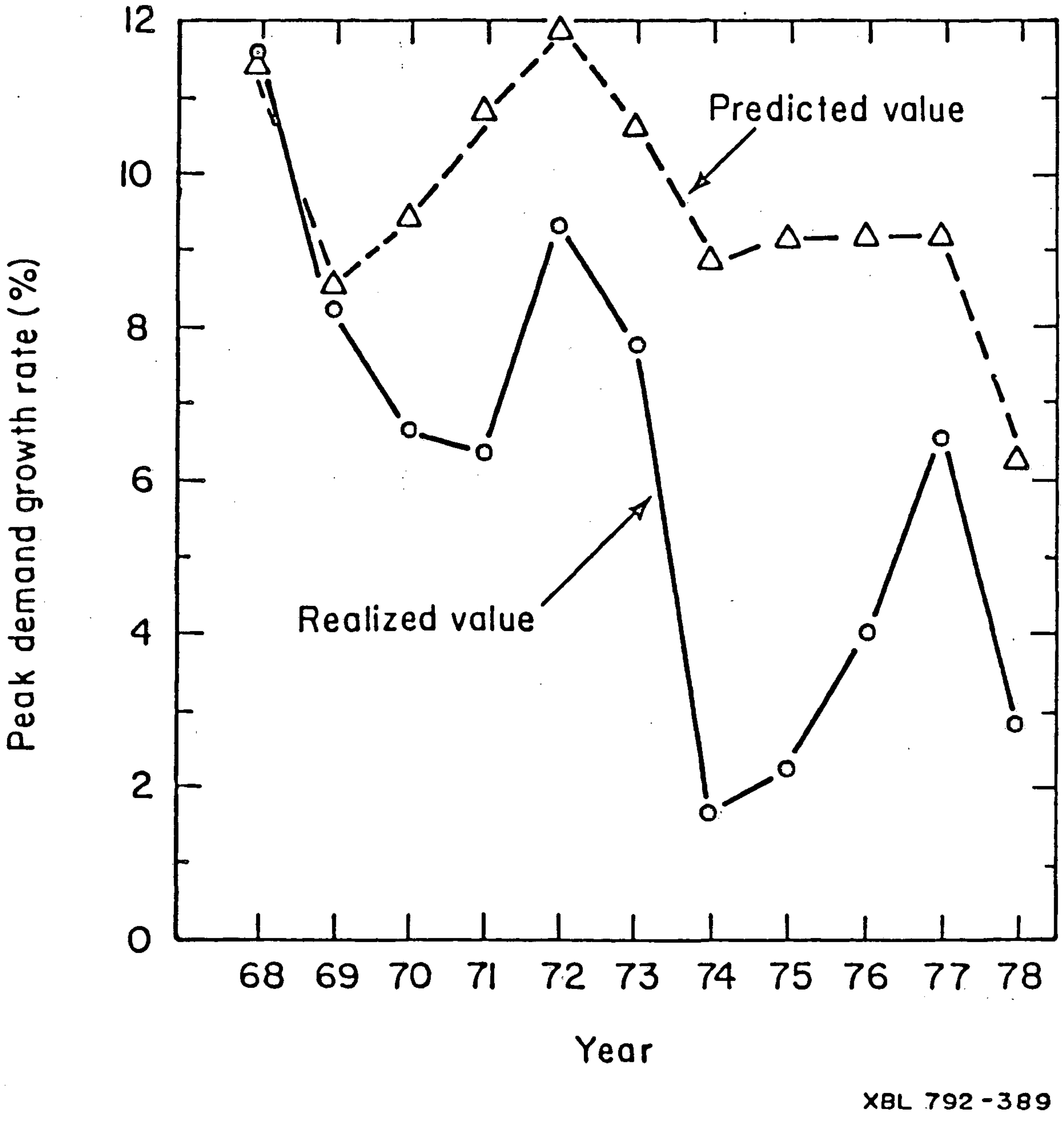

Figure 3-3 Planning forecasts of future demand

3.3 Construction Financing Costs

The utility industry developed an accounting practice to deal with construction financing costs which transforms them into capital costs, and incorporates them into rate base when the plant comes into service. The guiding legal and regulatory principle at work here is the "used and useful" doctrine with respect to the recognition of plant costs in customer rates. The basic idea is that customers ought not to pay for uncompleted projects which provide no service. Therefore the finance costs associated with such investments should not form part of retail rates. Nonetheless, construction finance costs are real, and must be recovered ultimately. To accomplish this they are capitalized.

Comtois provides convenient formulas for calculating how much of the final accounting cost of a plant is capitalized interest. The magnitude is clearly time-related, as is the escalation component of final cost. Numerical examples illustrate that under current lead-time and interest rate conditions, capitalized interest can be a large fraction of cost.

In addition to the capitalization of interest costs, there is also a related accounting convention on the utility's income statement for these costs. The income statement is an annual summary of revenues, expenses and earnings reported by all companies to their shareholders. The 1982 income statement for the Southern California Edison Company is attached. We can see the treatment of constructing financing costs in this case. The essential idea is that these costs appear as credits to income which do not correspond to actual current cash flows. These credits are something like regulatory promissory notes. They are called an Allowance for Funds Used During Construction (AFUDC). Present practice separates AFUDC into an equity component listed under "Other Income" and a debt component that is a negative entry under "Interest Expense." For Southern California Edison in 1982 the former was $209 million and the latter was $94 million (see Table 3-6). Together this $303 million represents 55% of the utility's Net Income of $555 million. Since AFUDC is not cash, the reported Net Income substantially over-states the cash position. This distortion can create financing problems for utilities with large construction programs by making capital more expensive. Therefore, in the 1970's proposals for alternatives to AFUDC accounting were made, and in many cases implemented. The principal alternative is called Construction Work in Progress (CWIP) in Rate Base, or CWIP for short.

Table 3-6

STATEMENTS OF INCOME
Thousands of Dollars

		1982	1981	1980
		Year Ended December 31,		
Operating Revenues:	Sales	$4,266,950	$4,026,548	$3,631,373
	Other	35,652	27,808	29,744
	Total operating revenues	4,302,602	4,054,356	3,661,117
Operating Expenses:	Fuel	1,778,553	2,078,393	1,729,552
	Purchased power	449,348	479,813	280,675
	Provision for energy cost adjustments	367,565	(90,273)	361,600
	Other operation expenses	496,585	441,939	392,593
	Maintenance	210,160	193,397	228,269
	Provision for depreciation	220,927	202,182	187,959
	Taxes on income - current and deferred	177,251	197,865	38,683
	Property and other taxes	65,486	59,885	69,652
	Total operating expenses	3,765,875	3,563,201	3,288,983
Operating Income		536,727	491,155	372,134
Other Income and Income Deductions:	Allowance for equity funds used during construction	209,485	162,879	121,488
	Interest Income	34,571	39,025	33,889
	Taxes on non-operating income - credit	100,655	54,261	30,358
	Other	965	13,896	1,524
	Total other income and income deductions	345,676	279,061	187,259
Total Income Before Interest Charges		882,403	761,216	559,393
Interest Charges:	Interest of long-term debt	360,915	281,626	227,163
	Other interest and amortization	59,367	59,351	55,493
	Total interest charges	420,282	340,977	282,656
	Allowance for debt funds used during construction	(93,633)	(69,673)	(40,799)
	Net interest charges	326,649	271,304	241,857
Net Income		555,754	489,912	317,536
Dividends on Cumulative Preferred and Preference Stock		72,396	67,888	60,950
Earnings Available for Common and Original Preferred Stock		$ 483,358	$ 422,024	$ 256,586
Weighted Average Shares of Common and Original Preferred Stock Outstanding and Common Stock Equivalents (000)		94,257	85,610	73,241
Earnings Per Share		$5.13	$4.93	$3.50
Dividends Declared Per Common Share		$3.38	$3.10	$2.84

CWIP is essentially a pay-as-you-go method of financing construction. Instead of delaying the recognition of financing costs in rates with AFUDC, CWIP treatment places the direct construction cost in rate base as it occurs. Thus under CWIP rates go up sooner than with AFUDC, but not as much. The AFUDC part of capital cost is eliminated, so that the total plant cost in rate base is less. To examine and compare these procedures from the perspective of shareholders, we use a simple model due to Rothwell.

We consider a two-period world. Construction occurs in period 1 and production in period 2. We want to incorporate the prospective nature of the rate-making process, so we will distinguish between estimates of certain variables (indicated by "^" over the symbol) and realized values of those variables. We denote the rate of return on capital by r, the construction cost by K and the output by Q. In the case of CWIP the revenue requirement is $\hat{r}\hat{K}$ in period 1. This is a fixed fee which must be paid by all customers without receiving any output. In period 2, the regulator estimates a price $\hat{P} = \frac{\hat{r}\hat{K}}{\hat{Q}}$ based on an estimate of output. Actual revenues are $\hat{P}Q$. For AFUDC, the period 1 revenues are zero. In period 2 the price is set higher than for CWIP because of capitalized interest. We summarize the cash flows as follows:

	Period 1	Period 2
CWIP	$\hat{r}\hat{K}$	$\frac{\hat{r}\hat{K}}{\hat{Q}} Q$
AFUDC	0	$\hat{r} \frac{(\hat{r}\hat{K} + \hat{K})}{\hat{Q}} Q$

We want to discount these cash flows and compare them. Let us call d_1 and d_2 the discount rates appropriate to each period. These rates are essentially the required rate of return, or the market discount rate to which we have referred previously. Let us calculate the present value of CWIP (PV_c) and AFUDC (PV_a), as follows:

$$PV_c = \frac{\hat{r}\hat{K}}{d_1} + \left(\frac{\hat{r}\hat{K}}{\hat{Q}}\right) Q \left(\frac{1}{d_1 d_2}\right), \tag{3-13}$$

and

$$PV_a = \hat{r} \left(\frac{\hat{r}\hat{K} + \hat{K}}{\hat{Q}}\right) Q \left(\frac{1}{d_1 d_2}\right). \tag{3-14}$$

Notice that we are discounting back to period 1, so the period 2 cash flows are discounted twice.

Next we assume that $d_1 = \hat{r}$. This means, that the regulator has correctly identified the cost-of-capital in period 1 and made it the basis of rates in period 2. This simplifies Eqs. (3-13) and (3-14) to

$$PV_c = \hat{K} + \frac{\hat{K}}{d_2} (Q/\hat{Q}) , \tag{3-15}$$

and

$$PV_a = \frac{(\hat{r}\hat{K} + \hat{K})}{d_2} (Q/\hat{Q}) . \tag{3-16}$$

The second term of Eq. (3-15) also appears in Eq. (3-16). We can eliminate it to find when

$$PV_c > PV_a$$

This occurs when

$$\hat{K} > \frac{\hat{r}\hat{K}}{d_2} (Q/\hat{Q}) ,$$

or

$$1 > \frac{\hat{r}}{d_2} (Q/\hat{Q}) . \tag{3-17}$$

Of course, Eq. (3-12) can be used to find when $PV_c < PV_a$ by reversing the direction of the inequality. The intuitive content of this relation is that the value of CWIP or AFUDC depends on whether the estimated rate of return is greater than, equal to or less than the cost of capital and whether actual output is greater than, equal to, or less than estimated output.

Eq. (3-17) says that CWIP is preferred by shareholders when either the allowed return on capital in period 2 is less than required, or actual output is less than estimated output, or both. Conversely AFUDC will provide greater revenue when the return on capital exceeds its cost (the Averch-Johnson condition) or when output (sales) exceed forecasts, or both. Broadly speaking the conditions favoring AFUDC occurred before 1970, and those favoring CWIP occurred after. The data in Table 2-1 on the market to book value ratio (MBV) of utility stock indicates that returns were generally less than the cost of capital after 1973. The forecast error is estimated for 1968-1978 in Figure 3-3. It shows systematic over-estimates of demand starting in 1970 and growing worse after 1973.

Of course, this evidence is not conclusive. The model which yields Eq. (3-17) is simplified, and even contains ambiguous cases. We cannot tell a priori the direction of the inequality when the two ratios have opposite effects. That is, $r > d_2$ and $Q < \hat{Q}$, on the one hand, and $r < d_2$ and $Q > \hat{Q}$ on the other could make $PV_c \gtrless PV_a$. Moreover the basic orientation of this model is a project evaluation framework, where systematic effects of the larger environment are neglected. In the 1970's it became increasingly important to understand such effects as they impinged on the planning environment.

The Livingstone and Sherali paper on CWIP is one example of a broader analytic perspective on the CWIP vs. AFUDC evaluation. The usual style of such evaluations is a multiple year cash flow comparison of the alternative regulatory treatments. These cash flows are then discounted at some appropriate rate and compared. As the preceding two period model should suggest the choice of discount rate will turn out to have a crucial effect on the outcome. There may also be differences among studies in the accounting conventions used to generate revenue requirement cash flows.

The Livingstone and Sherali paper considers the effect of multiple projects, or more generally, construction expenditures growing at an exponential rate. They find that this changes the results of the typical single project analysis by making CWIP more burdensome. The basic idea here is that as the utility's construction budget grows, CWIP in rate base weighs increasingly heavily in the early years of the cash flow. Discounting the future AFUDC costs coming from an increasingly remote future provides less and less of a present burden.

This completes our discussion of construction financing costs, per se. The remaining aspects of these issues have to do with market valuation of utility shares as a function of CWIP or AFUDC accounting. The question is whether the regulatory choice over the treatment of construction financing costs influences the price of the stock. It is clear from Eq. (3-17) that there ought to be an effect. But the model from which this conclusion follows is so simplified that it may distort or at least over-emphasize the magnitude of the effect. To examine this issue in more detail, we will make one last attempt to understand the cost of equity capital for utilities. This will involve a review of theory as well as an examination of evidence.

3.4 Cost of Equity Capital

The evidence on electric utility shareholder returns shows a steady deterioration during the 1970's. Table 2-1 and Figure 3-4 are various illustrations of this general trend. It is difficult, however, to untangle the various forces at work during this period in order to arrive at any quantitative explanation which is wholly satisfactory. In this section we review several approaches to this problem and compare their results.

Let us begin with the Haugen, et al., paper on interest rate risk. This paper begins with a simple comparison of the response to interest rate changes by utility versus industrial stocks during the period 1967-1975. This shows that the former are more sensitive to interest rate changes than the latter. A simple explanation of this phenomenon can be made by comparing the relative length of asset lifetime. Utilities have longer lived assets than industrial firms. This translates into a greater change in the present value of earnings from utility assets as the discount rate changes. This is because interest rate changes are strongly correlated with changes in the market discount rate. Formally it can be shown that for an annuity the partial derivative of present value with respect to the discount rate increases with the length of the annuity period. This can be expressed

$$\frac{\partial}{\partial r} PV = \frac{\partial}{\partial r}\left(\sum_{i=1}^{n} \frac{k}{(1+r)^{i}}\right)$$

$$= nk\left(\frac{\partial}{\partial r}\left[\frac{1-x^{n+1}}{1-x} - 1\right]\right) \tag{3-18}$$

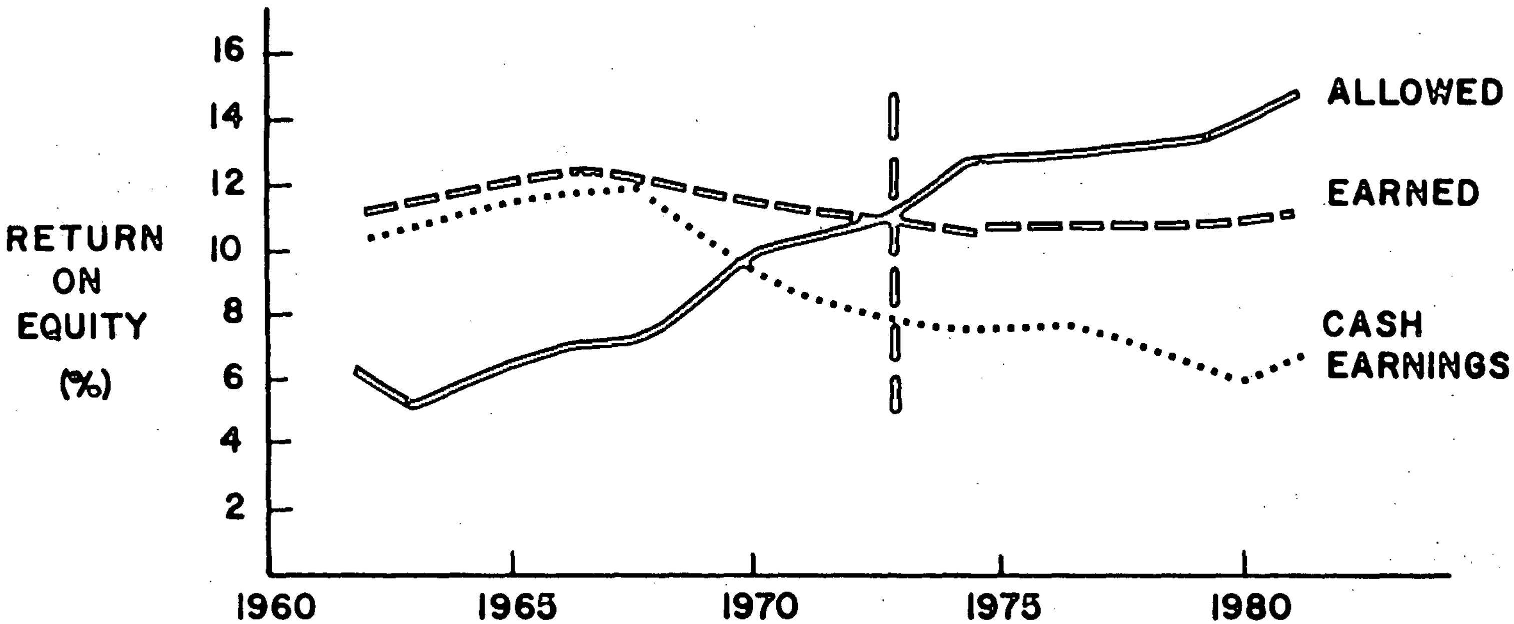

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Figure 3-4 Deterioration of utility shareholder returns in 1970's

where

$x = 1/1+r$

K = annuity payment

Eq. (3-18) can be expanded to produce

$$\frac{\partial\ PV}{\partial\ r} = nk\left[\frac{1-(n-1)x^{n}\ +nx^{n+1}}{(1-x)^{2}}\right]\left(\frac{-1}{(1+r)^{2}}\right), \tag{3-19}$$

which is larger with increasing n. In the case of bonds, it is clear that longer term bonds are more sensitive than shorter term bonds to changes in the market discount rate.

While the downward pressure on utility stocks during the 1970's may be broadly attributed to generally increasing interest rates, this relation is difficult to understand with any quantitative precision in specific cases. Since the goal of security analysis is to understand the particular price determinants of individaul stocks, statistical models of security prices have been constructed on more or less ad hoc empirical grounds. The Benore paper represents an example of this genre for electric utilities in the late 1970's.

Benore rejects standard finance theory models such as the DCF model of minimum acceptable returns (Recall discussion of MAR at Eq. (2-6)). In particular, he seeks insight into the optimal dividend policy which will maximize the price of an electric utility stock. Standard finance theory asserts that dividend policy is irrelevant because efficient capital markets look only at the "real" economic returns and not at petty details of financial policy such as the dividend payout ratio. Benore builds a regressian model of the market to book value ratio (MBV) in which payout ratio (PR) plays a prominent role. The model takes the form

$$MBV = a_1 + a_2(ROE \times EPSG) + a_3(PR) + a_4(PLANT\ G)$$

$$+ a_5(FUEL) + a_5(AFCHIGH), \tag{3-20}$$

where

ROE	=	expected return on equity
EPSG	=	expected earnings per share growth rate
PR	=	payout ratio
PLANTG	=	projected growth of gross plant
FUEL	=	fuel mix index

AFCHIGH = AFUDC greater than 35% of net income.

All the estimated coefficients in Eq. (3-20) have the expected sign, all are significant at the 5% level except fuel. Nonetheless Eq. (3-20) is totally arbitrary in nature. There is no particular reason why the explanatory variables were chosen in this manner. The AFUDC indicator, for example, is designed to single out only those companies with AFUDC above the then current average rate. The coefficient a_5 has the value -0.05. This means that MBV goes down 5% for companies above the 35% threshold. Benore admits that this formulation was chosen for its 1% impact on the R^2 of the equation. Other estimates of the impact of AFUDC on common equity will be reported later. For now, however, it is useful to see how Benore uses Eq. (3-20) to modify the DCF model and find the optimal payout ratio. Using average values for his electric utility sample, Benore constructs an example of the role PR plays in deterimining MBV. This is summarized in Table 3-7.

In Table 3-7 we summarize Benore's calculation of MBV (line d). While the cases show a linear increase in MBV with increasing PR, Benore warns against extrapolating beyond MBV=1. At this point, he warns, regulators will reduce ROE to prevent "excess" profits to shareholders. Therefore MBV=1 must be the maximum, so PR should be chosen to approach that value. In this case PR=73% would be optimal.

Table 3-7 also allows comparison with the DCF model of minimum required returns. The DCF model is Eq. (2-6). In lines (e) and (f) we calculate the dividend yield and DCF return. Line (f) suggests that required returns go down as payout ratio increases. This should not happen in any equilibrium capital market, because investors are not thought to respond to financial policy changes. Moreover, if they did, there should be some discounting for the increased bankruptcy risk associated with high payout ratios. An equilibrium interpretation of the Table 3-7 data is that the DCF model must be modified to discount ESP Growth. If we assume that Cases 1-5 all imply the same cost of capital, then we can calculate the discount on EPS Growth as follows

$$\left| \frac{\Delta \text{ Div. Yield}}{\Delta \text{ EPS Growth}} \right| = 2/3 \ . \qquad (3\text{-}21)$$

Eq. (3-21) says that EPS Growth is only worth 2/3 of its value in the Benore model compared to DCF model.

Table 3-7

EXPECTED MBV AND COST OF EQUITY: BENORE MODEL

	Case 1	Case 2	Case 3	Case 4	Case 5
a) Payout Ratio	.5	.6	.7	.8	.9
b) ROE	11.7%	11.7%	11.7%	11.7%	11.7%
c) EPS Growth	5.6%	4.4%	3.2%	2.0%	0.7%
d) MBV	.86	.92	.98	1.04	1.10
e) Div. Yield	6.8%	7.6%	8.4%	9.0%	9.6%
f) DCF Return	14.4%	12.0%	11.6%	11.0%	10.3%

d) $= \hat{a}_1 + \hat{a}_2(b)(c) + \hat{a}_3(a) + \hat{a}_4(\bar{x}_4) + \hat{a}_5(\bar{x}_5) + \hat{a}_6(\bar{x}_6)$

e) $= \frac{ROE}{MBV} \cdot PR$

f) = (c) + (e)

More recent models include AFUDC as an explicit determinant of the cost of equity capital. One version of such a model is formulated as follows

$$\text{Cost of Equity} = \text{ROE/MBV} + \alpha(\text{AFUDC/NI}), \qquad (3\text{-}22)$$

where

$$\text{AFUDC/NI} = \text{AFUDC as a percent of net income}$$
$$\alpha = \text{constant estimated by regression} = .027$$

Eq. (3-22) has been used by NERA, a utility oriented consulting firm, for economic evaluation of utility specific project analysis.

To illustrate the performance of these various models we collect some recent market data in Table 3-8 and analyze it in Table 3-9. Of the three models for cost of equity used in Table 3-9, Benore seems to out-perform DCF and NERA. The latter two seem to predict counter-intuitively. While DCF clearly shows that superior performer NEES has the lowest cost of equity, it does not make sense for PG&E to be judged riskier than LILCO or PECo which are both in much poorer financial condition. The weakness of PECo is similarly not captured in the NERA model, nor is the relative strength of SCE. The Benore model seems to get the order of risk, (or conversely financial strength) most nearly correct. The relative magnitudes, however, are still difficult to judge with confidence.

A final empirical note on the Value Line estimates in Table 3-9. As a check on the ROE estimate, one can use the estimated payout ratio PR, MBV, and Dividend Yield to calculate a ROE estimate. The relations among these variables were used in line (e) of Table 3-9. Performing this check yields a slightly different ROE estimate than the one cited in Table 3-9. This calculation is left as an exercise. None of the qualitative features of Table 3-9 results would change with this variation.

One broad conclusion which emerges from the data and calculations of Tables 3-5 and 3-8 is that large scale construction (measured for example by AFUDC/NI) is a negative influence on the cost of equity capital. To develop such a relation in an equilibrium context, one must resort to a model such as the one used by Peck in which returns are measured against a market required rate of return. The basic relation used for this

Table 3-8

CURRENT MARKET DATA*

Company	Price	Dividend	Div. Yield	Book Value[a]	MBV	AFUDC/NT
SCE	38-3/8	3.52	9.2	37-5/8	1.02	0.54
PG&E	15-1/8	1.60	10.6	16-5/8	0.91	0.44
PECo	16-5/8	2.12	12.7	18-3/4	0.89	0.63
NEES	37-3/4	3.20	8.5	32	1.18	0.31
LILCO	15-5/8	2.02	12.9	19-1/8	0.82	0.88

(a) Value Line data for 1983
(b) Annual Reports, 1982
* As of September 26, 1983

Table 3-9

PROJECTED EARNINGS, DIVIDENDS AND ESTIMATED COST OF EQUITY

Company	EPS Growth[b]	ROE[a]	PR[a]	DCF	Benore	NERA
SCE	7.5	16.0	0.63	16.7	14.2	17.2
PG&E	7.0	13.0	0.76	17.6	15.3	16.5
PECo	4.0	12.0	0.89	16.7	15.4	14.2
NEES	7.0	16.0	0.66	15.5	13.2	14.4
LILCO	4.0	13.5	0.81	16.9	15.6	18.9

(a) Value Line estimate for 1983
(b) Value Line projection to 1986-1988

purpose is given by

$$MBV = R/K + \frac{R-K}{K}\left(\frac{1}{K+R\theta}\right)\frac{I}{K}, \qquad (3-23)$$

where

R = allowed ROE,

k = cost of equity,

θ = debt/equity ratio,

I = level of investment,

and

K = book value.

Eq. (3-23) says that MBV >1 if and only if R>k. But the difficulty with this equation in practice is that k is so difficult to estimate. Table 3-9 shows that it varies from company to company. Even if this problem were solvable, the empirical treatment of the investment term I also presents difficulties.

Peck concludes from Eq. (3-23) that with R< k, the shareholder wants to minimize I. But the indivisibilities associated with large scale projects actually allow for little flexibility. In our small sample of 5 utilities NEES should have the largest investment program since it has the highest MBV. But measured by AFUDC/NI, NEES has the smallest program. The other four companies may be interested in reducing investment requirements, but are constrained by past commitments. Eq. (3-23) would suggest that SCE would be relatively more prone to invest than the other companies since its MBV is about 1.02. In practice, however, it is not possible to distinguish this empirically.

In summary, the financial upheavals of the 1970's have not been sorted out in theory or in practice. With declining productivity of investment, there is clearly less incentive for capital intensity than in the past. But quantitative measures of this incentive are difficult to come by, and theoretical models only somewhat suggestive. All that can be said with certainty is that the clarity of the Jeynes' decision rule is gone. Project evaluation must be done in the overall context of the firm and not on the limited side-by-side method of the past. How to incorporate firm-level constraints is still a subject of much uncertainity. To broaden our perspective, it will be useful to survey some of the methods which have been used to examine new projects in a systems context. We will begin with a discussion of reliability and reserve margins.

3.5 Reliability and Reserve Margins

One of the unique engineering features of electric utility systems is the need for reserve capacity. Electricity is not easily (inexpensively) stored, so that when random outages occur to generating units there must be excess capacity ready to pick up the load very quickly. To understand this phenomenon better, and to plan for reserve requirements, utility engineers have developed some numerical techniques to measure power system reliability. The most popular of these is a calculation known as the Loss of Load Probability (LOLP). In this section we will define LOLP, discuss its measurement, interpretation and use in various analytical settings.

LOLP is a measure of the aggregate match between generation resources and loads on an electric utility grid. It is an abstract measure which ignores such important practical constraints as the transmission configuration and the causes of generation outages. All generation unit failures are thought of as independent random events. The LOLP for a power system is defined by a relation such as

$$LOLP = \sum_{i=1}^{n} \text{Prob}_i \; (\tilde{X} < L)/n \; , \tag{3-24}$$

where

$\tilde{X} = \Sigma \tilde{X}_j$ is the aggregate capacity of the generators $\tilde{X}j$ each of which is a random variable,

L = load,

and

n = the number of periods per year in which the system configuration differs.

Eq. (3-24) is an average LOLP calculated over the n periods per year which reflect the different mix of generating units available for service, i.e. not on scheduled maintenance.

The notion of "forced outage" is a central idea in the LOLP framework. The definition of a forced outage is an event requiring the shutdown of a plant immediately; i.e., the shutdown cannot be delayed until some more convenient time. There are technical subtleties associated with this notion, particulary where partial curtailment of plant output is involved. In many cases a condition will occur at a plant which operators interpret to require a limitation on output. This is called a "partial outage" as opposed to a "full outage" when the entire plant is shut down. As indicated in the definitions associated with Eq. (3-24), maintainence or scheduled (i.e., not forced) outages are treated as a change in the total generation capability.

Because LOLP is an abstract concept, it is useful to develop a little intuition about the practical correlates of different LOLP profiles. A convenient representation of the LOLP function for this purpose is the graph of LOLP versus load such as Figure 3-5. The first qualitative feature of the LOLP curve in Figure 3-5 is the nearly exponential nature of the function. The vertical axis in plots such as Figure 3-5 is typically scaled logarithmically. The horizontal axis is linear. An exponential change in LOLP with load would be a straight line.

One question which can be asked about graphs such as Figure 3-5 concerns the concentration of the LOLP over the year. Some power systems are "needle peaking" in nature. Their maximum loads are very much above average levels and persist for only very short periods. This can concentrate the risk of generation deficiency. This phenomenon cannot be distinguished from a system which has the risk diffused more evenly, but is still very reliable on the average. Both such systems will have "steep" rather than "flat" graphs of LOLP vs. load. This means that small changes in load produce large changes in risk. To distinguish needle peaking from high reliability, it is convenient to refer to the reserve margin.

The standard definition of reserve margin is given in the following relation

$$R_m = \frac{\text{Installed Capacity - Peak Load}}{\text{Peak Load}} \; . \qquad (3\text{-}25)$$

Eq. (3-25) can be measured for any system without regard to LOLP. To associate the two concepts, reference is usually made to a reliability objective. Utility planners usually accept some version of the "LOLP equal to one day in ten years" criterion for the minimally acceptable risk of generation insufficiency. There are many ways to apply the

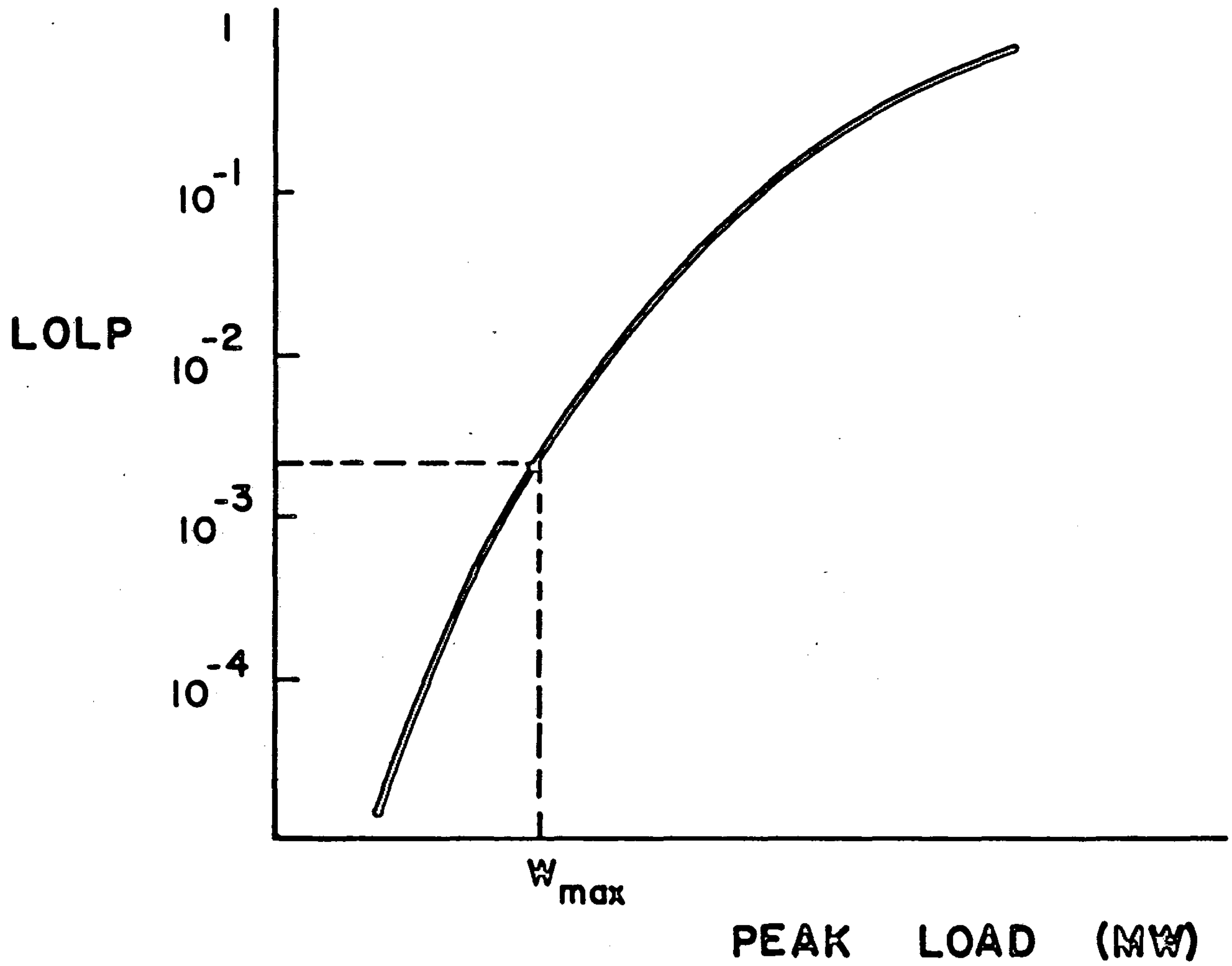

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Figure 3-5 LOLP versus load

notion of "one day in ten years" to specific calculations. All of them eventually end up associating some maximum peak load W_{max} with the minimally acceptable risk as in Figure 3-5. Using this correspondence we can define a particularly interesting reserve margin, the required reserves. Let us call this R_mReg. It is defined by

$$R_m\text{Reg} = \frac{\text{Installed Capacity} - P_{max}}{P_{max}} \qquad (3\text{-}26)$$

R_mReg will vary from system to system, even for the same conventions on calculation procedure. A common rule-of-thumb relation is that R_mReg = 20% corresponds to LOLP = 1 day/10 years. There is, of course, much variation in actual circumstances. Generally speaking, however, the lower R_mReg is, the more reliable the system.

Conversely, systems which are unreliable will have a large reserve requirement. Typically, unreliable systems have relatively "flat" LOLP graphs compared to reliable ones. R_mReg is related to the variance of the available capacity. This increases with high generator forced outage rates, and in situations where one or two units make up large fractions of total capacity (> 20%). Generally speaking when R_mReg is high, then the supply variance is high and so a little more load does not increase risk very much. This means the LOLP curve rises slowly; i.e., is flat.

For project evaluation purposes, we are interested in incremental LOLP. Different units will have different incremental effects on required reserves. There are many ways to study these effects, but one of the most lucid discussions was the 1966 IEEE paper of L.L. Garver of the General Electric Company. Garver observes that when a new unit is added to a power system the LOLP curve shifts outward as in Figure 3-6. Unless the incremental unit is perfectly reliable, the incremental load W_2-W_1 will be less than the maximum capacity of the unit. Garver defines the incremental load W_2-W_1, measured at the LOLP criterion level, as the "effective load carrying capability" (ELCC) of the unit. ELCC is sometimes referred to as "effective capacity," as in Lyons. It can be expressed as a percentage of the unit's maximum capacity, or in megawatts un-normalized to any standard.

Garver also introduces an approximation technique which will allow estimation of ELCC in particular cases where a numerical LOLP study has already been performed.

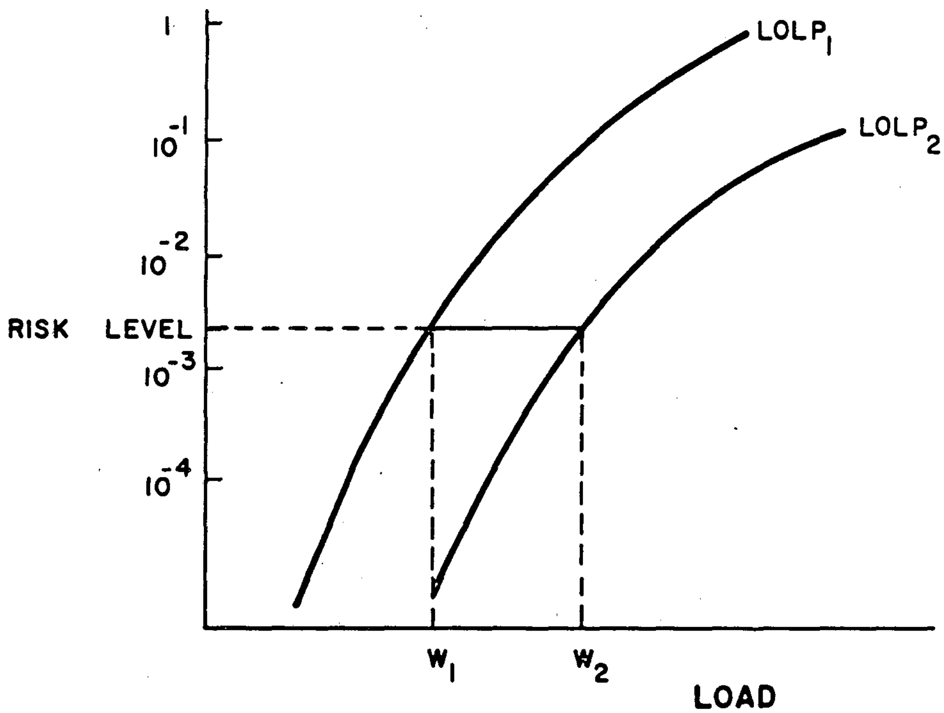

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Figure 3-6 LOLP curve shifts outward when new unit is added to power system

His well-known equation for ELCC is given by

$$\text{ELCC} = C - m \ln\left[(1-r) + re^{c/m}\right], \tag{3-27}$$

where

c = nominal capacity of the new unit,

r = forced outage rate of this unit,

and

m = system specific parameter.

Eq. (3-27) reduces the ELCC calcualtion to the process of estimating the parameter "m" for specific systems. This parameter is related to the slope of LOLP graphs such as Figures 3-5 and 3-6. The estimation requires a transform of such graphs into LOLP vs. Reserve Requirements. This is straight-forward and produces a graph such as Figure 3-7.

Figure 3-7 shows how the parameter m is estimated from the transformed LOLP graph. It is clear that such LOLP vs. Reserve Requirements graphs slope the opposite way from Figures 3-5 and 3-6. As reserve margin goes up, LOLP goes down and vice versa. The parameter m is just a linear approximation to the incremental reserve sensitivity of the system.

The purpose of ELCC calculations is to supplement the highly simplified busbar cost calculation for use in project evaluation. Busbar cost, you will recall, assumes implicitly that all generation projects have the same incremental impacts on reserve requirements. This is not true. Examination of Eq. (3-27) shows that ELCC as a fraction of nominal capacity goes down as capacity goes up and as forced outage rate increases. In the 1970's it became clear that generator unit size and forced outage rate were correlated. Large units performed worse than smaller units. Thus ELCC gradually became incorporated into project evaluation techniques. The Lyons paper of 1979 is one of the first published exercises of this kind.

Numerous problems remain in the area of reliability assessment. LOLP is a highly artificial concept, ignoring many practical constraints and complexities. Even if the concept was more representative of the actual problem, it is not obvious what a reasonable criterion for LOLP should be. Not only is the notion of "one day in ten years" ambiguous, it is very hard to cost-justify. Economists have tried to place values on the reli-

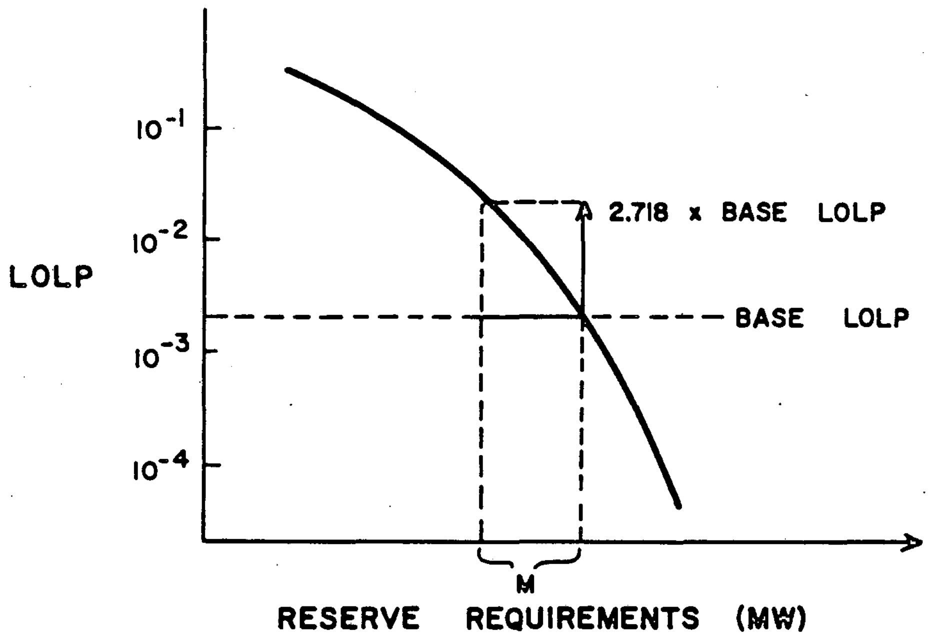

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Figure 3-7 LOLP versus reserve requirements ability of electric power supply to different users. Surveys show enormous variation. (See, for example, the National Electric Reliability Study, 1981.) Broadly speaking the U.S. electric utility system is very reliable compared to less developed countries. Indeed unreliable power supply is often used as an indicator of a low stage of economic development. But if too little reliability is costly, too much can also be expensive. Deciding how to optimize here is very difficult.

A final word about reserve requirements and growth is important. It is not accidental that ELCC became an issue in project evaluation when electric demand growth slowed substantially in the 1970's. The reason for this can be illustrated from some of Garver's original data. He shows ELCC for five successive 600 MW units added to a system. While the first unit has ELCC = 60.4% of capacity, the last has ELCC = 84.7%. Thus for a given size generating unit, there is an ELCC penalty for the first units of this size. If load growth is high, then many units of a given size will be required so a scale economy in ELCC can be said to exist. With declining load growth, only the first one or two units at the highest capacity level will be installed, and therefore they will have lower ELCC on the average than in the high growth case.

This discussion illustrates concretely how factors relating to the firm as a whole enter into project evaluation. The 1970's saw a number of such developments. To survey these approaches we must introduce a new level of analysis called capacity expansion planning. This kind of study is considerably more complex than the project evaluations we have seen up to now.

3.6 Capacity Expansion Models

Capacity expansion models are designed to generalize the simple project evaluation methods to a comprehensive consideration of the utility system as a whole. In practice, of course, these models do not focus on all possible effects. Perhaps the single most important feature of such models is the attention given to total system fuel cost. Oil price increases during the 1970's made much existing generation capacity uneconomic in static cost minimization terms. This means that if the utility could instantaneously adjust its generation resources to minimize total cost, then coal and nuclear units would replace oil and gas-fired capacity. To calculate the trade-off between new plant investment and fuel cost reductions, capacity expansion models do complex and tedious production cost computations. We will summarize briefly the nature and results of such computations.

The typical starting point for a production cost model is the load duration curve (LDC). This is a graph representing all hourly kW demands, sorted from highest to lowest. An example is given in the upper panel of Figure 3-8. The peak load is at the origin of the x-axis and the minimum load is at the right hand extreme of that axis. Production cost models simulate the economic dispatch of the system's generators to meet the load at minimum cost. Due account is taken of scheduled maintenance, forced outages and often other engineering constraints. Due to the complexity of the computations, it is often difficult to develop an overall picture of the basic cost structure of the utility. To facilitate such a global approximation the screening curve simplification has been developed. An example is given in Figure 3-8.

Screening curves attempt to approximate the optimal mix of generating units. Different technology types have different proportions of fixed and variable cost in their total busbar cost. A low fixed-cost, high variable cost technology, such as a combustion turbine, is better suited to serving peak loads of short duration, than "base" loads which are constant throughout the year. To represent the different proportions of fixed and variable cost factors, we plot total annual revenue requirements versus capacity factor on the bottom panel of Figure 3-8. Nuclear plants, whose costs are largely fixed, have a large intercept and small slope on this graph. Conversely combined cycle (CC) and gas turbine (GT) units have low fixed cost and high variable cost, i.e., low intercept and steep slope.

The keys to minimizing costs are the intersection points of each technology total cost function. By mixing production from "peaking" (CC and GT) and intermediate (C=coal) for the proper number of hours with the "optimal" base load generation, cost is minimized. This will be the envelope of each intersecting curve that is closest to the x-axis. Where CC & GT crosses C, for example, tells us the maximum number of hours it is least expensive to run peaking plants compared to intermediate. Projecting this up to the LDC we can find the amount of peaking capacity corresponding to this maximum economic running time. This is just C_3-C_2. Similarly the amount of "intermediate" capacity would be C_2-C_1, and baseload capacity would be C_1.

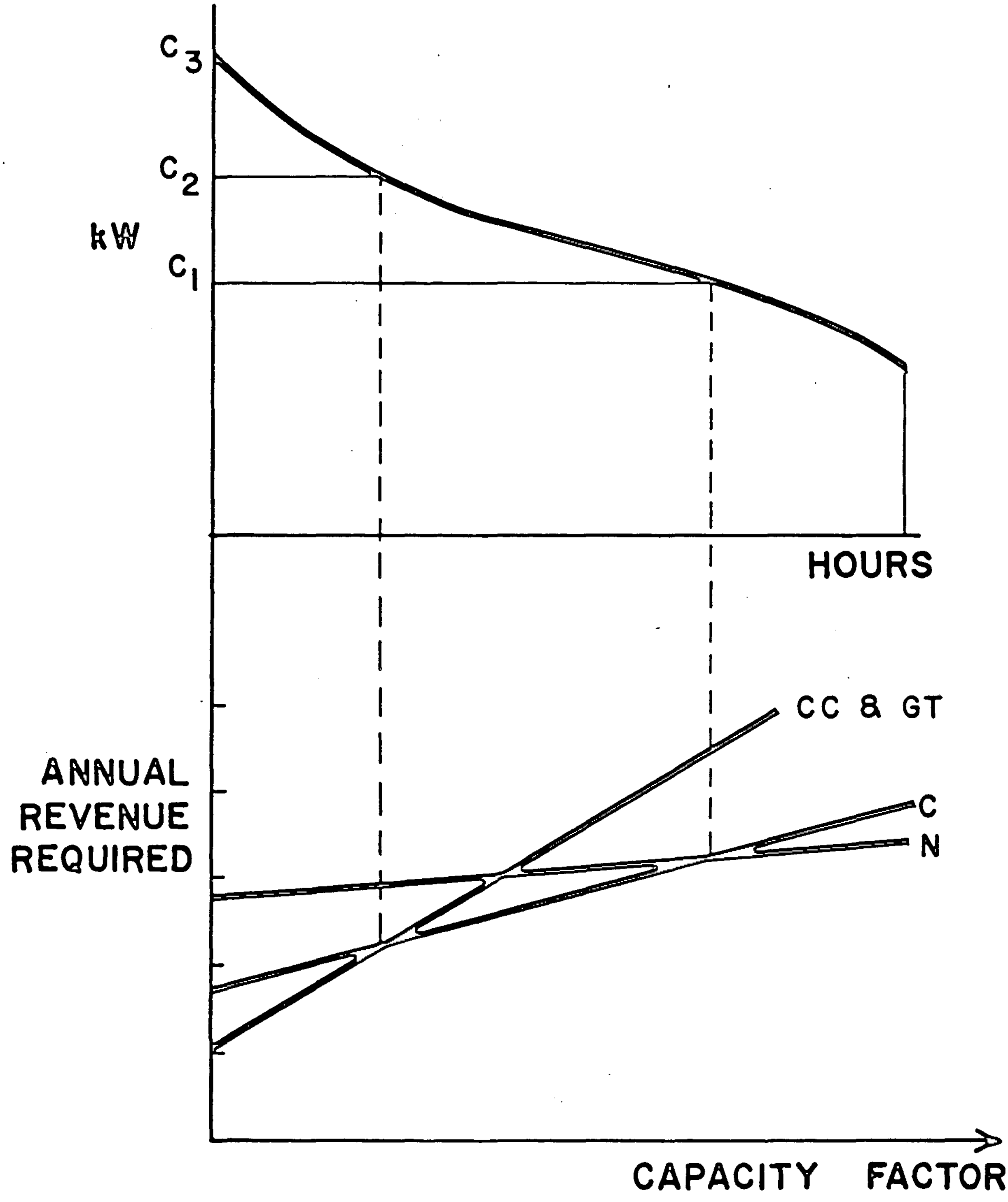

Figure 3-8 All hourly kW demands sorted from highest to lowest

The importance of such calculations is that they provide an indication of the ideal capacity mix. For many utilities in the 1970's, screening curve analysis indicated that they were very far from the optimal configuration. Typically the results suggested that more baseload coal and nuclear units were required to displace oil and gas-fired generation. Simple busbar cost calculations do not capture the value of baseload capacity expansion, because they do not capture the production cost savings associated with approaching a more optimal configuration.

Figure 3-9 is a block diagram representing the basic logic of capacity expansion models. Taking the load forecast as an exogenous input, a generation expansion plan is specified which will meet anticipated demand. This plan is then used as input to both production costing and reliability evaluation. If the LOLP, or other reliability index, does not meet the criterion of adequacy then the expansion plan must be revised. This is represented by the loop in Figure 3-9 between Generation Expansion Plan and Reliability Evaluation. For a given plan, both the investment cost and the production cost must be calculated. Both terms are typically calculated at the level of the firm. The investment cost means all fixed costs such as interest, depreciation, taxes, fixed O & M and return on equity. Production cost is also a systemwide calculation.

There is substantial variation in the way the various steps indicated in Figure 3-9 can be carried out. In principle, all possible expansion paths could be examined and the one involving minimum revenue requirements would be selected. This is computationally infeasible, so there is usually some exogenous determination of a small number of alternative supply scenarios that are tested. Capacity expansion models differ primarily in how they handle the calculations within each step. Very often the financial detail associated with calculating the fixed or investment cost aspect of corporate revenue requirements is simplified. Many of these models are insensitive to regulatory practices such as the difference between CWIP or AFUDC accounting. Even where financial detail is substantial, the models cannot be run to optimize a financial objective. The most common emphasis in these models is production cost. A representative recent package of these models called EGEAS which was developed by the Electric Power Research Institute (Caramanis, 1982) illustrates this point.

Regardless of limitations associated with the structure of capacity expansion models, the really practical problems associated with their use is uncertainty of input assumptions. With escalation of capital and fuel costs at varying rates, it is extremely

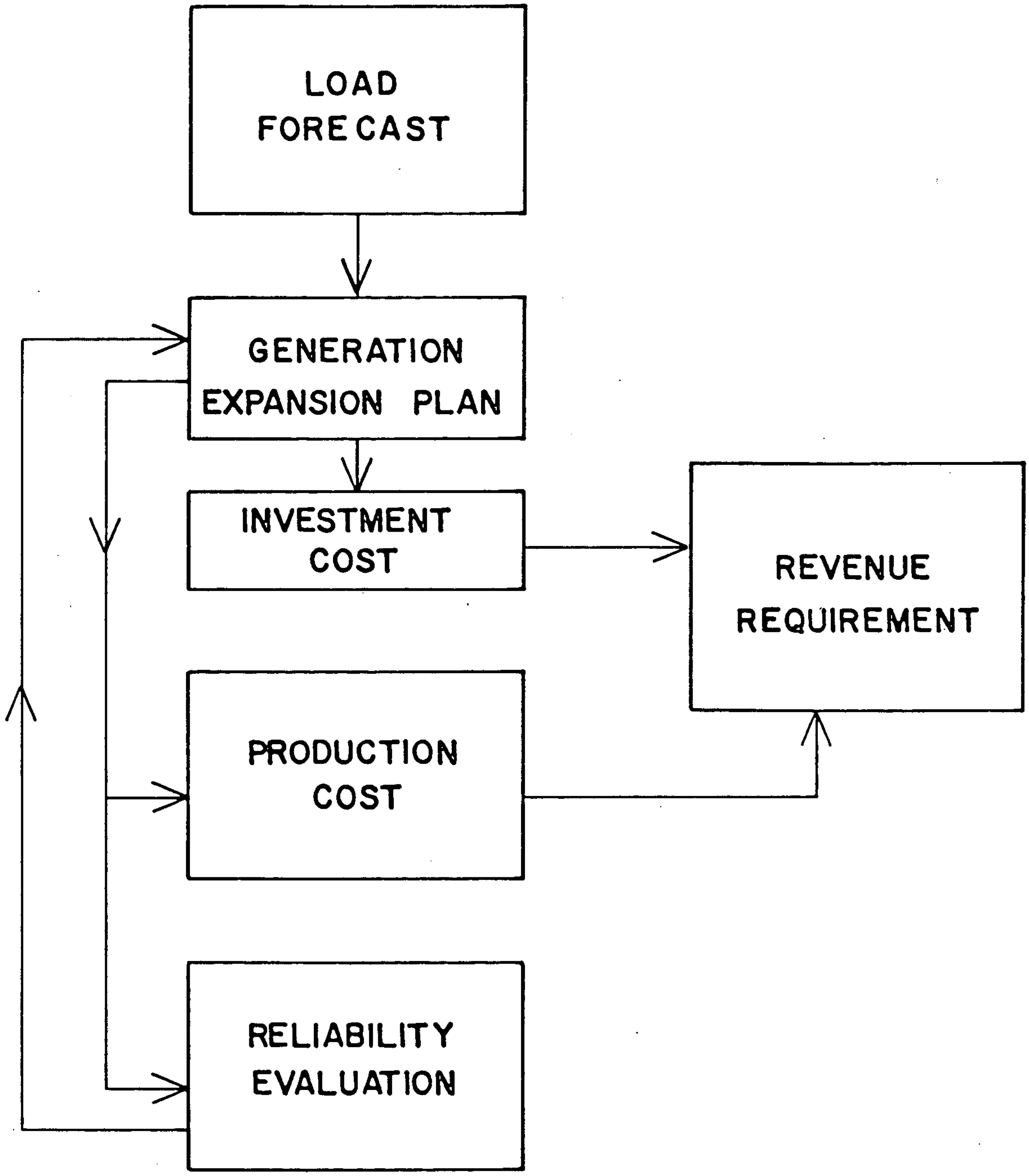

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Figure 3-9 Capacity expansion model block diagram difficult to get a fix on cost functions. Similarly, the uncertainty in future load growth makes it difficult to have confidence in a given forecast. With conditions of rapid change, studies based on one set of assumptions would soon become obsolete.

Indeed, capacity expansion models were often brought into play after projects had been selected by cruder project evaluation techniques. The essential reason for this is that the basic rationale for central station project contruction changed during the 1970's from growth to fuel cost reduction. When new capacity must be added to meet future demands, then sophisticated capacity expansion models are not needed, busbar cost wil do. As load growth diminished and reserve margins grew to unprecedented levels, the need for new capacity could have nothing to do wih reliability anymore. Instead it was fuel cost reduction which became the critical strategic fact underlying new construction. A graph of total consumer cost including the cost of insufficient capacity as a function of investment level, would show some optimal level of capacity which minimizes total fixed and operating cost. In practice, however, capacity expansion modeling appeared in a dynamic framework which is schematically illustrated in Figure 3-10.

In Figure 3-10 we characterize the environment surrounding planning method changes in the 1970's. Roughly speaking t_1 represents the pre-1974 period and t_2 the post 1974 periods. During t_1 utilities planned for new capacity using simple busbar cost methods, based on high growth demand forecasts, and without much of a constraint from the regulatory process. Nonetheless, forces set into motion at the end of this period soon began to make life more complex. Federal regulation of new plant construction tended to increase lead times and costs, as we have seen. The effect of rate increases, especially from fuel cost, began to dampen demand growth to the point where projects under construction and planned during the later 1970's no longer seemed quite so necessary.

At this point, capacity expansion modeling came into play, rationalizing new plant construction from the long-run fuel cost savings perspectives. To achieve these long run economies, large rate increases were necessary during period t_2. Regulators typically refused to increase revenue requirements as much as utilities requested. Thus earnings deteriorated, the financial market turned hostile toward electric utilities, and another cycle of rate requests was initiated. To justify construction expenditures during this period, utilities repeatedly appealed to the reduction in long run fuel cost that would eventually benefit ratepayers. In the short run, however, CWIP in rate-base was

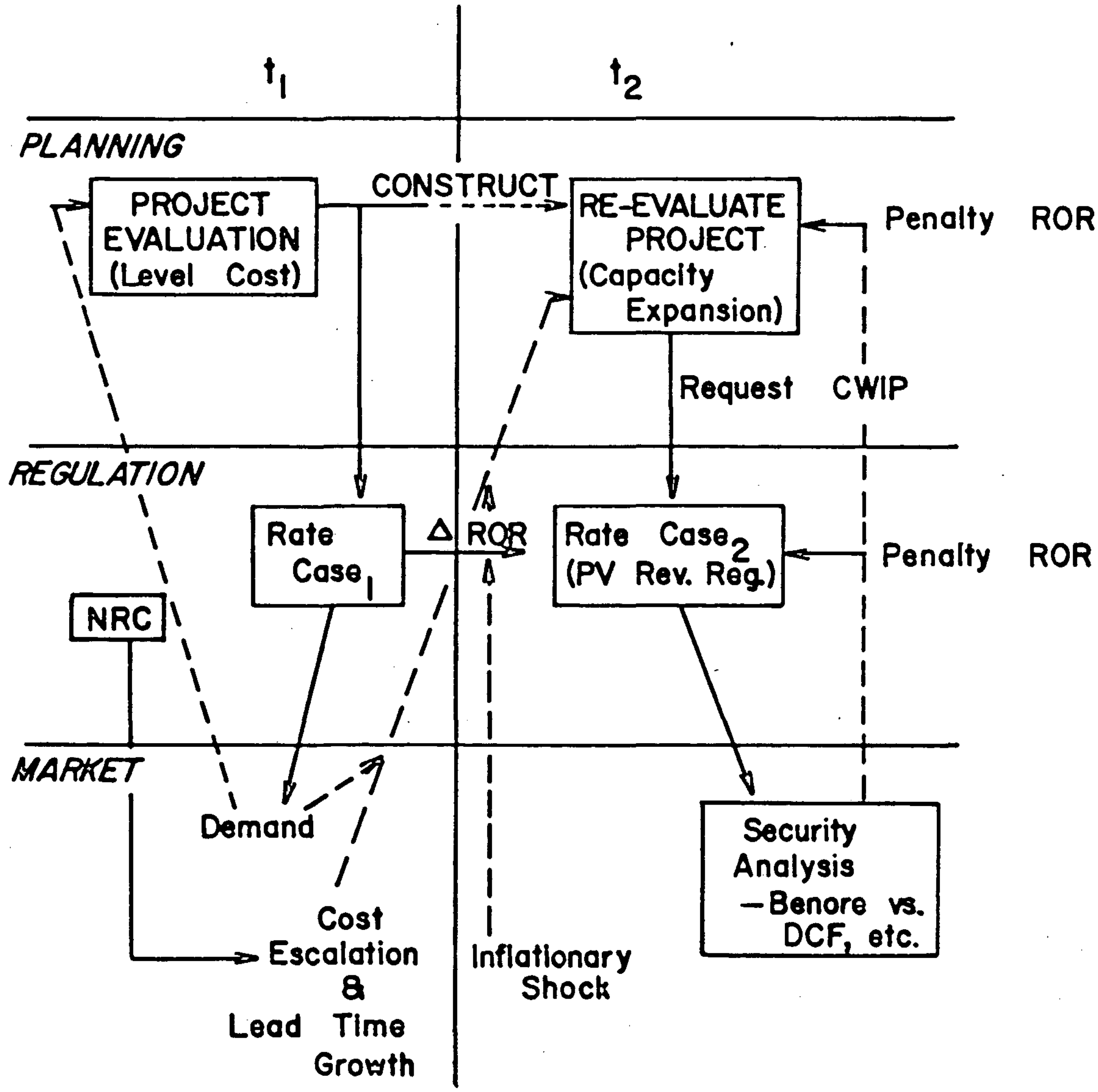

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Figure 3-10 Characterization of environment surrounding planning method changes in the 1970's necessary or the utility stock would fall in value, thereby increasing the cost of equity to ratepayers.

Various parts of this story were told in various ways in different circumstances during the latter part of the 1970's. But the more elaborate the arguments, the less convincing they became to all parties involved. By the end of the 1970's a substantial dissatisfaction with traditional analytical procedures and assumptions emerged within the electic utility industry. One sympton of this dissatisfaction was a remarkable committee report by the Long Range System Planning Working Group of the IEEE's Power Engineering Society. This group reported a survey of industry planners concerning their attitude about the significance and validity of current assumptions embedded in their standard procedures. Lack of consensus and lack of a clear vision of the future was obvious in every major area. Forecasting was acknowledged to be very difficult. The cost minimization basis for making economic choices was questioned. Regulatory pressures expressing changing societal goals were seen to be transforming the very concept of a utility. Details can be found in the IEEE Transactions on Power Apparatus and Systems v. PAS-99 (May/June, 1980) pp. 1047-1056.

Another way to illustrate the breakdown in capacity expansion modeling is to focus on newer and more sophisticated techniques designed for the current environment. The two papers we will focus upon illustrate particular inadequacies of capacity expansion models by proposing ways to treat problems previously ignored. The Keeney and Sicherman paper tries to model explicitly the way in which utility decision-makers trade-off different attributes of projects that are not usually considered commensurable. The Merrill paper also deals with incommensurability; in this case the trade-off between environmental pollution and economic cost. Merrill adopts a social rather than the utility perspective.

3.7 Analyzing Incommensurables in Capacity Expansion Decisions

A common critique of economic methods of analysis is that often important social values are neglected because there are no market prices attached to these "commodities." Environmental impacts are a widely cited example of this phenomenon, although regulation has "internalized" these costs increasingly by setting certain minimum impact standards. Nonetheless, social choices are involved in the production of electricity with regard to the type and level of environmental impact resulting from different technology options. These choices are not usually made with a great deal of explicit analysis. Information is difficult to gather in this area, because the processes involved are complex and vary with local conditions. The Merrill paper illustrates some of the difficulties.

Merrill is interested in assessing cogeneration development in the New York City area. Cogeneration is the combined production of heat and power at a site where both products can be used. The waste heat from central station power plants is not typically put to any economic purpose. Heat is expensive to transport and/or store, so it cannot be easily transferred from central station power plants. In New York City, cogeneration is attractive primarily because electric rates are so high that there is a substantial incentive for customers to leave the utility system and produce their own power. A number of other factors such as local tax policy and environmental regulation standards also affect the relative costs to potential cogenerators. The Consolidated Edison Company, (ConEd) which supported Merrill's research both financially and technically, has publicly opposed cogeneration development in its service territory. ConEd has argued that when cogenerators leave the utility system, the rates of other customers will have to be increased to cover the utility's large fixed costs. For this and other reasons, a prominent ConEd executive has referred to cogeneration as "a wolf in sheep's clothing," (Schwartz, 1981).

Merrill seeks to assess cogeneration development from a broader social perspective than the private interest of ConEd. He focuses attention on three variables: fuel use, air quality and total electricity revenue requirements. To study how these variables change under different development scenarios, Merrill runs standard models for utility production cost, revenue requirements and regional air quality. The total revenue requirements are the sum of utility costs and cogenerators costs. This aggregation will implicitly account for the revenue shift problem ConEd has complained about.

To perform a strategic analysis Merrill makes a large number of model runs. Indeed the number is so large that special procedures are necessary to understand and generalize the functional dependencies implicit in the results. This is accomplished by a procedure called SMARTE functions. These functions are linear regressions of the decision and exogenous variables on the attribute variables of fuel use, air quality and cost. The SMARTE functions turn the vast output of the simulation scenarios into more tractable summary form. Such functions then allow the analysis of an exhaustive set of scenarios which maps the intermediate region of the space of attribute, decision and exogenous variables which was sampled in the initial simulations.

Having generated what looks like a "complete" picture of all alternatives, Merrill must reduce the results in a way which reveals the "best" choices. He plots results for two attributes at a time. The resulting scatter plots generally reveal a trade-off curve that is the boundary or envelope of points in the feasible region which minimizes the undesirable value of one attribute or another with the other one fixed. A number of operations can be performed on the trade-off curves or the scatter-plot itself to illustrate important qualitative features of the decision. We will examine a number of these.

In Figure 3-11 Merrill shows a shift in the cost vs. SO_2 trade-off curve as cogeneration alternatives are added to an electricity development scenario based on converting ConEd's oil-fired generation units to coal. Cogeneration increases cost (upward shift) and decreases SO_2 (shift to the left) compared to coal conversion. Such qualitative conclusions are still insufficiently explicit to yield a "best" strategy, so Merrill introduces Pareto optimality and related concepts.

Strategies can be eliminated from consideration if compared to alternatives the values of attribute variables which are superior can be found. Formally, if x and y are two strategies and a(i,x) and a(i,y) are the values of the i^{th} attribute associated with x and y, then strategy x is <u>dominated</u> by strategy y if

$$a(i,x) > a(i,y), \text{ for all } i. \tag{3-28}$$

A strategy which is undominated is Pareto optimal.

Figure 3-12 shows that many Pareto optima exist for this problem. This does not aid decision-making because there are still too many alternatives. Therefore Merrill introduces <u>Strong Pareto optimality</u> and the corresponding notion of <u>near domination.</u> The intuitive notion is that many optima are "close" and so they can be reduced to as single better representative which is "near-by." Formally this requires that a small number Δi be chosen so that strategy x will be nearly dominated by strategy y if

$$a(i,x) > a(i,y) - \Delta i, \text{ for all } i. \tag{3-29}$$

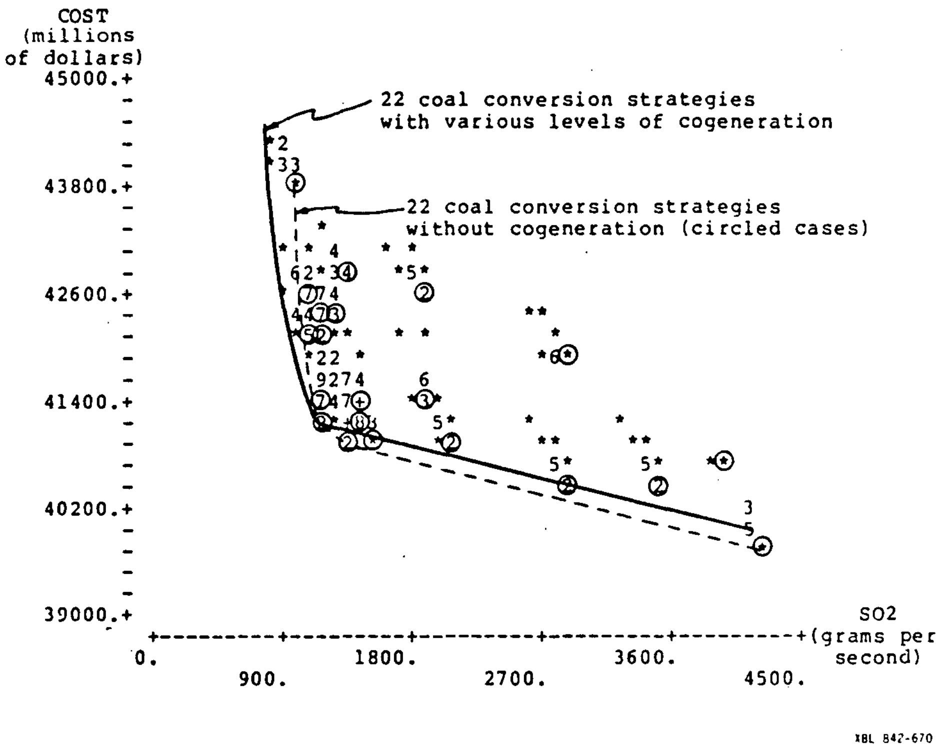

Figure 3-11 **Shift in cost versus SO_2 trade-off curve as cogeneration alternatives are added**

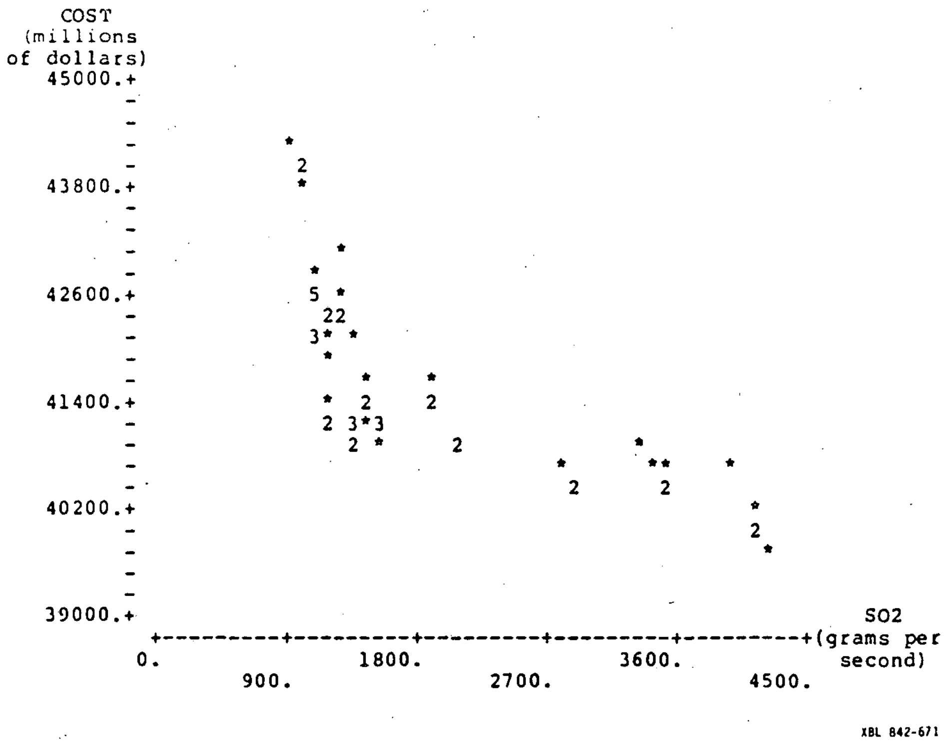

Figure 3-12 **Pareto optimal strategies in terms of five attributes, projected onto cost/SO_2 plane**

This definition allows a significant reduction in the number of "important" strategies which can then be studied in detail.

For this study Merrill reduces the number to seven. He plots these in Figure 3-13. Examining the results, he excludes three on the grounds of unacceptable SO_2 levels. The remaining strategies involve substantial coal conversion and no cogeneration. This is precisely the preferred approach of Consolidated Edison management.

From a methodological perspective, the weakest link in the analysis is the strong Pareto optimality notion. The concept is both numerically arbitrary and artificial in its concept of utility. The numerical arbitrariness is obvious since results depend upon the value of Δi. This is serious, but not fatal. If the "nearness" concept were sound, it would be possible perhaps to find a metric for it. Unfortunately, "nearness" as defined in Eq.(3-29) implicitly assumes a highly restricted social utility function. Essentially Eq. (3-29) says that all attributes are equally important. This follows since the distance defining "nearness," Δi, is the same for all attributes. If one attribute were worth more than another, i.e., had greater utility, then there should be different measures of nearness for each. Merrill's method allows him to escape estimating explicit trade-offs among attributes, by the agnostic assumption that they are all equally important. This is not really an escape, however, only a very specialized arbitrary representation of social utility that has not particular claim to reality. After all, it is the analyst who chooses the attributes in the first place, and assigns them weight implicitly.

It is exactly at this point where the Keeney method claims its superiority. The goal of the Keeney-Sicherman paper is to elicit explicitly the decision maker's utility function. This includes a specification both of the relative weights attached to attributes and the quantitative trade-off among them. This is a practical goal only if a single decision-maker can be identified and interviewed in the appropriate manner. For the case study reported in the paper such an interview was conducted. It does not necesarily represent the actual values of the Utah Power and Light Company management; principally because only one executive was interviewed.

The results of the analysis are summarized briefly in Table 3-10. This represents the relative importance of attributes, expected impacts associated with the two most important attributes and the trade-off between them. Table 3-10 indicates that considerations other than busbar cost and feasibility are of minor importance. Of all

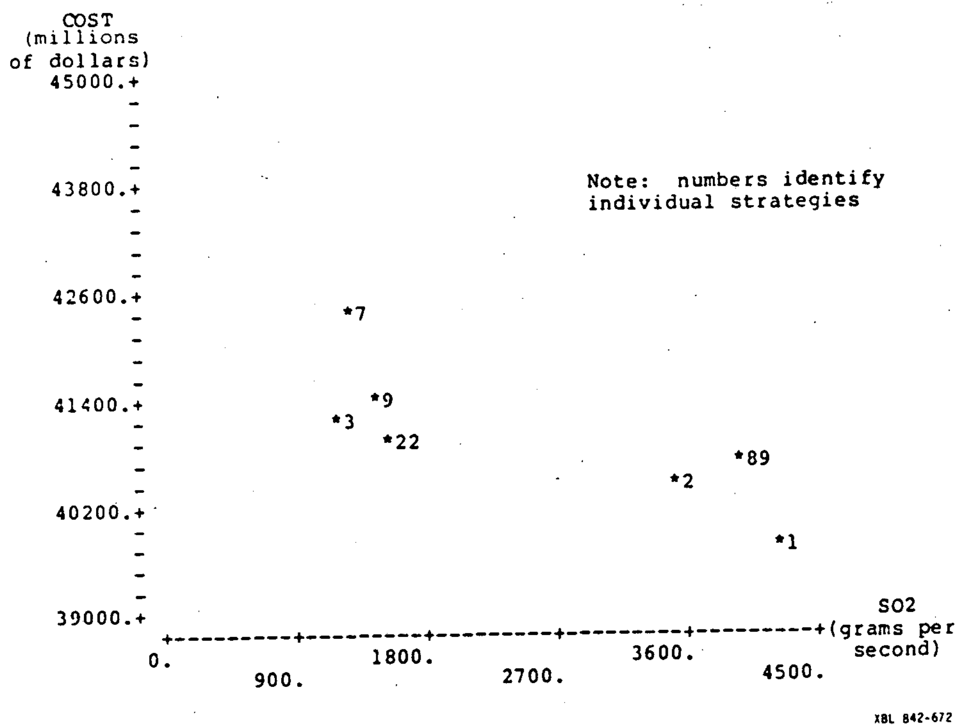

Figure 3-13 Strongly Pareto optimal strategies in terms of five attributes, projected onto cost/SO_2 plane

Table 3-10

RESULTS OF THE UP&L ANALYSIS

Attributes	Relative Weight	Expected Values Coal	Expected Values Nuclear	Attribute Trade-off 1% Feasibility = 1.6 mills/kWh Coal	Attribute Trade-off 1% Feasibility = 1.6 mills/kWh Nuclear
Busbar Cost (mills/kWh)	0.34	60.7	47.4		
Feasibility (prob. of completion)	0.54	0.60	0.31	64.3	110.5 Equivalent cost (mills/kWh)
Health and Safety	0.09				
Environmental Impact	0.002				
Expected Utility		0.53	0.40		
Equivalent Cost (mills/kWh)		125.	157.9		

those considered health and safety impacts have the most weight. To evaluate attributes Keeney devises "impact" scales which are used to contrast coal from nuclear plant choices. The "economics" impact is busbar cost. The feasibility impact is the probability of completion (i.e., not being cancelled). Since feasibility carries so much weight in the decision, it is worth examining the concept in detail.

Keeney identifies nine circumstances which might lead to plant cancellation. The major factor is "financing difficulties." The nuclear plant has a 50% probability of cancellation compared to 25% for the coal plant due to the financing difficulty factor. To aggregate this factor with all others Keeney uses a multiplicative risk model. If each factor has a probability of cancellation P_i, then the overall probability that the facility will be cancelled p is given by

$$(1-p) = \prod_{i=1}^{n} (1-p_i) \tag{3-30}$$

Eq. (3-30) expresses the probability of completion which is reported in Table 3-10.

Keeney says very little about his concept of financing difficulties except that the nuclear project is "perceived to be more capital intensive, and requires a greater financing at the beginning of the project." This comment is strange in light of the busbar cost data cited in the paper. Here the nuclear plant is presented as 10-15% <u>less</u> capital intensive (total project capital cost). Is this a contradiction? It is hard to tell. But for a methodology which is supposed to clarify and rationalize intuition, something is clearly wrong here.

Keeney's real interest is to trade-off the feasibility risk against the nuclear busbar cost advantage. He elicits a trade-off relation from his executive interview. One percent feasibility equals 1.6 mills/kwh. Applying this monetization of risk makes the nuclear plant 25% more expensive in "equivalent cost" than coal. The busbar cost advantage of nuclear (roughly 21%) is swamped by the feasibility cost. Sensitivity analysis indicates that if the "price of risk" went down by a factor of 3, then the choice of coal or nuclear would be indifferent.

What are we to make of this analysis? Is this rational decision-making or a rationalization of inconsistent perceptions? One gets the feeling that this study has found the right answer for the wrong reason. Clearly nuclear plants are riskier than coal plants, and this risk will deter investment. But Keeney has told us little about where the risk comes from, and how it is valued. We do not know how to interpret the trade-off parameters; where they come from, what they mean. As with the Merrill paper we get the appearance of comprehensive reasonable consideration of all effects. But when the complexity gets too great, arbitrary simplifications are used to reject most of the data generated so laboriously.

These studies represent the high water mark of capacity expansion modeling. They embody the end of a line of thought, rather than the beginning. As capacity expansion models reach this level of sophisitcation, utilities have ceased expanding capacity. The alternatives analyzed by Keeney are no longer the principal activities on the margin of the electricity supply system. Merrill is closer to the spirit of the current climate, where the decentralized choices of electricity users are the dominant effect on utility system development. To prepare ourselves for studying the "post-central station era," it is necessary to develop a systematic understanding of the price regulation mechanics which go into rate-making. This is the next subject to which we will turn.

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Chapter 4

PRICE REGULATION MECHANICS

4.1 Introduction

Most of our discussion up to now has focused on the determination of revenue requirements either in the context of project evaluation or for the utility as a whole. The regulator's role in determining these is somewhat circumscribed. The two principal areas we have touched on are: (1) identifying the cost of common equity, and (2) the choice between CWIP and AFUDC accounting. But a good deal of rate-making activity is devoted to the question of which customers will pay what portion of these total revenue requirements. This is essentially a distributive function. Before entering into a general discussion of what is involved in this process it is useful to distinguish different perspectives on what rate-making is supposed to do generally.

We can distinguish two broad strands of thought about the rate-making process. One is accounting oriented and organized around an average cost of service notion. The other tradition has its origins among economists and its principal concern is with marginal costs. Economic theory is largely concerned with resource allocation efficiency. The standard micro-economic theories suggest that resource allocation is efficient when commodities are priced at their marginal cost. Because marginal and average costs are seldom identical, marginal cost pricing has never been the practical norm in utility rate-making. Nonetheless, the changing nature of the marginal costs of electricity has resulted in increased attention to this concept. The resulting tension between the accounting and economic points of view is inherent in current rate-making practices.

The basic conflict between the accountant and the economist concerns which cost must be given dominant consideration. There is little argument about the functional components of cost or the need for procedures which go from aggregate revenue requirements to managable tariff schedules (unit costs) that will produce those revenues. The problem of rate-making amounts to adopting a dominant perspective, and then reconciling it with the most important information associated with the neglected point of view. The "reconciliation" can take many forms. In the discussion which follows we shall have many occasions to refer to this process. But to organize the material concretely we shall be forced to emphasize one perspective more consistently than another. Due to its theoretical importance, we will give primacy to the marginal cost point of view.

The practical difficulties of marginal cost pricing are twofold. First the costs must be identified concretely. This is an engineering economic task. The technical features associated with "small" (i.e. marginal) changes in consumption must be determined and then costed. Once the costs have been catalogued and measured, revenue generated by pricing at this level must be compared to revenue required to cover total expenses. In the era of declining costs this comparison usually resulted a deficit. That is really what declining cost meant, marginal costs below average revenue requirements. Since no one had adequate solutions to funding this revenue deficit, marginal cost pricing was not widely advocated. In the current period the opposite situation obtains. Marginal costs are usually greater than average rates, so that marginal cost pricing means a revenue excess. In a period of increasing cost, utility rates should somehow serve a rationing function to limit excessive consumption. It is this concern which leads to current interest in marginal cost theory. In the discussion which follows we will see many instances in which this theory must be reconciled with average cost notions. The underlying concern with marginal costs in the current environment, however, stems from the resource allocation benefits associated with marginal cost prices.

Rate regulation can be characterized as a four stage procedure. The stages are: (1) determination of total revenue requirements, (2) estimation of the time variation in costs, (3) allocation of costs to customer classes, and (4) design of unit cost tariffs. We will discuss the basic task of each stage, the principal distinctions (or concepts) associated with each stage, and the data used to assess particular circumstances. Controversial issues will be identified and illustrated with examples.

The first stage (determination of total annual revenue requirements) can be quite simple in the accounting or average cost paradigm. From the marginal cost perspective the issues become complex. We will review PG&E's estimate in some detail. Regardless of the perspective, there is commonly agreed to be a <u>functionalization</u> of costs among the following categories:

1. Demand-Related Costs
    a) Generation
    b) Transmission (4-1)
    c) Distribution
2. Energy-Related Costs
3. Customer Costs

In most cases it is obvious which costs fall into which categories. Fuel, for example, is an energy related cost. So are variable operations and maintenance expenses. It is equally clear that high-voltage lines are transmission expenses. There are, however, interesting problems concerning costs that may overlap categories. The boundary between distribution costs and customer costs is one example. While meters are clearly customer costs, the small distribution transformers on low voltage lines may be assigned to one category or the other. The PG&E example will provide more detail on this particular issue.

The controversial issues in stage one have often centered on the legitimacy or prudence of certain management decisions. If extra expenses were incurred by the utility compared to what a prudent and reasonable course of action might have been, should customers be obliged to pay for these in rates? This issue arises in the case of abandoned construction projects. It has also been raised with respect to fuel supply contracts. If every management action will result in cost recovery, regulation is not providing any incentive for management efficiency. Conversely, if perfect hindsight results in continual second-guessing, management will either take no risk, or lose the financial capability of attracting capital.

Finally it should be observed that generation demand related costs are not necessarily the same thing as the fixed costs of generation capacity. The NARUC (National Association of Regulatory Utility Commissioners) Cost Allocation Manual recognizes that some part of generation plant investment cost may be energy-related. The example used to illustrate this is the hydro-electric storage reservoir. Larger dams result in more water storage. It is the volume of water which is proportional to total energy (kWh). As the height of a dam increases the water storage (energy) increases faster than the capacity which can be produced (kW or demand-related cost). Therefore some part of the dam's capital cost is energy related. It should be noted that there are some analogies with large baseload thermal plants here. As you will recall the ELCC (demand related capability) of such plants can be quite low. Their principal virtue is low energy cost. This subtlety will often be obscured in a marginal cost analysis, but is less easily lost in an accounting framework. We will examine this issue in more detail later.

The second stage of the rate setting process is a characterization of the <u>time variation of costs</u>. The cost of electricity production, like other production costs, depends on the supply/demand balance. Costs increase as this balance becomes more constraining and conversely. In electric power systems there are consistent patterns in the time variation of costs which are studied in the rate making process. This stage may be characterized by the following tasks:

1. Determination of Costing Periods
   a) Load statistics
   b) LOLP Variation
2. Generation Capacity Costs (4-2)
   a) Engineering characterization of capacity response to load changes
   b) Valuation of capacity
3. Transmission & Distribution Demand Data (T&D)
4. Energy-Related Costs

To simplify analysis it is common to group time periods into more or less homogeneous sets. The qualitative difference between "peak" and "off-peak" periods is quantified in this first task. Either load statistics or LOLP variations or both are used to define a small number of (4-6) of costing periods. The cost associated with the functional categories are then assigned to costing periods by engineering analysis. LOLP-type methods are used increasingly to assign marginal demand-related generation capacity costs to costing periods. Average or accounting costs methods are typically less sophisticated. T&D demand is typically studied in less detail than generation related demand. Here the marginal and average cost allocation procedures are not too different. Because the problem of estimating marginal impacts on the T&D system is so difficult, only simple rules of thumb are possible. For energy related costs some form of production cost model is used to match cost changes to specified time periods.

The third stage in the rate-making process is to <u>allocate costs to customer classes</u>. This is usually done by first specifying the load characteristics of each customer class. These load characteristics can then be valued (or "costed") by using the previously defined costing periods. This makes class allocation fundamentally a load study problem in which the revenue responsibility of each class is determined. Often, however, other issues are brought to bear upon this stage. Questions of competition, price elasticity and price discrimination often affect these allocation procedures. One mechanism through which this occurs is the definiton of customer classes.

Although all utilities have residential, commercial and industrial rate classes, there is wide variation in the number of sub-categories within each broad class. In principal it would be possible to define very small homogeneous customer groups based on some common characteristic. The main reason to do this usually stems from outside forces such as competition or political pressure. Utilities commonly, for example, provide special lower rates to electric heating residential customers. It is usually claimed that this is cost-justified due to more "off-peak" consumption. It is also true, however, that these customers are more price elastic than the residential class as a whole. Therefore, the utility has an economic incentive to discount to them to optimize total revenue. If electric heating rates were too high, the utility would lose sales as these customers switched fuels.

A similar situation obtains among some price-elastic industrial customers. Here the motive to discount is often expressed in the language of regional economic development. If electric rates are so high that they make local industry un-competitive, the regional economic loss can be large. This will eventually be reflected in lower kWh sales and a shift of fixed cost responsibility onto non-industrial customers. To avoid this, it is better to keep rates to such customers low. An example of this is the aluminum industry in the Pacific Northwest. Here WPPSS-related costs may force industry closures, thereby raising residential and commercial rates.

The last stage of rate-making is the construction of <u>unit cost tariffs</u>. This is the culmination of the three previous stages and brings together all the previous issues and more. Usually this is an iterative process in which first approximations are refined by successive consideration of other factors. Broadly speaking the tasks of this stage can be characterized as follows:

1. Determine Preliminary Rates
   a) Unit Costs = Revenue Allocated/ Sales Estimated
   b) Revenue reconciliation
2. Tariff Design (4-3)
   a) Demand Charges vs. Meter Cost
   b) Rate Tiers
   c) Base Rates vs. Fuel Adjustment

The first stage is designed to develop a rough estimate of the unit costs. This requires both the previously developed class revenue allocation and a sales forecast. Unit costs are just the ratio of these. If the marginal cost approach has been used, then revenue requirements must be reconciled to the accounting cost perspective. This may be performed at the class allocation stage. If not, however, it must be done at the tariff design stage. There are several ways to achieve this reconciliation, and even different definitions of it. We will examine PG&E's discussion in detail.

Actual tariff design requires specificiaton of the metering technology. In many cases, it is economic to measure both demand and energy consumption (kW and kWh). In other cases the metering cost outweighs the benefit. In this situation rate tiers are often adopted to provide price discrimination for different kinds of consumption. In the era of declining costs, residential rate structures often had declining prices as consumption increases. We will study "inverted bloc" rates in which price increases with use to ration customer demand.

Finally, it is important to distinguish how particular revenues are recovered. Fuel costs are typically collected through automatic adjustment procedures in which there is little regulatory review. Fixed costs, which determine shareholder earnings, are subject to much more review and controversy. Administratively these "base rates" are determined in general rate cases separately from fuel adjustment. The tariff design may have different fractions of fuel cost and base rate in each component. Deciding how to apportion these is usually more a matter of art than science.

This general outline does not convey the level of complexity involved in rate—setting. To illustrate the process in detail we will follow through each stage in the procedure with concrete examples. We will begin with Pacific Gas and Electric Company's testimony on marginal cost in their 1983 general rate case.

4.2 Marginal Costs for Pacific Gas and Electric Company

Although economists have long advocated the marginal cost approach, they have been notoriously sloppy about the manner in which these costs should be identified. This has led to much confusion. To resolve the ambiguities California electric utilities, regulatory agencies and interested parties formed study groups to forge a methodological consensus. The goal was to develop a methodology that would allow practical estimates. PG&E's general rate case testimony presents their version of the resulting general approach. This can be summarized in the following two equations:

$$MC = \frac{\Delta C(R)}{\Delta L} + \frac{\Delta C(O)}{\Delta L} + \frac{\Delta C(I)}{\Delta L}, \tag{4-4}$$

where

$$\frac{\Delta C(I)}{\Delta L} = \left[\frac{\Delta FC}{\Delta I} + \frac{\Delta C(O)}{\Delta I} + \frac{\Delta C(R)}{\Delta I}\right]\frac{\Delta I}{\Delta L}, \tag{4-5}$$

where

$C(\cdot)$ = the cost function for R, O, and I,

R = reliability,

O = operations,

I = investment,

L = load,

FC = fixed costs,

and

Δ = first difference operator, i.e., $\Delta f = f_2 - f_1$

Eq. (4-4) says that marginal cost has three terms. The first is the change in reliability costs in response to a load change with no change in utility operations or investments. This term is often called the marginal shortage cost. The basic idea here is that system reliability must be maintained to avoid a shortage (or system outage), therefore the cost of preventing a change in reliability is the relevant measure. The second term of Eq. (4-4) is the marginal energy cost. It can be calculated from production cost models in a way that will be indicated below. The final term is the marginal investment cost. This term is expanded in Eq. (4-5).

Eq. (4-5) says that the marginal investment cost is the sum of three marginal cost changes with respect to investment times the marginal investment response to load changes. Of the three terms in the bracket, only the first is typically positive. Fixed costs, always go up with new investment. The second term is often called fuel savings, i.e., the (typical) reduction in total system operating costs resulting from new investment. The last term is the change in shortage costs with the new investment. This is roughly ELCC times the value of capacity.

PG&E's witness Fiske, the sponsor of this testimony, discusses Eq. (4-5) because it has been the subject of controversy. He observes that this expression can be negative, zero, or positive. Suppose it were negative. This would mean that PG&E's resource planners should add such investments to the system, since they would lower total costs. In fact, the planner should increase this type of investment until it has zero cost, or some constraint limits expansion. Negative net cost investments are not abundant, however. Even if some projects may appear to have negative costs, non-monetized costs may limit their development. Coal plants, such as the proposed then abandoned Allen-Warner Valley System, are examples of this phenomenon. The utility argues that such plants would lower costs in the long run, but are too "risky" to be built.

Fiske goes on to argue that Eq. (4-5) is in fact always zero. If a resource had negative net cost (the bracketed terms), then the investment would occur without respect to load changes. This means that $\Delta I/\Delta L = 0$. If a resource had positive net cost, the planner would also reject it as a response to load changes. Again, $\Delta I/\Delta L = 0$. This term, which Fiske calls the capacity response factor, is only positive when the net resource cost is zero. These are the marginal or deferrable resources, and there are lots of them. But for these Eq. (4-5) is also zero. Therfore, the investment term is always zero, and marginal cost is equal to the shortage cost plus the marginal operating cost.

By this argument Fiske has avoided identifying new generation projects as the marginal cost, and has placed the primary burden on marginal energy costs and shortage. This helps avoid discussion of new power plant costs in this context. If long run investment issues had to be discussed, the quantitative uncertainties would be substantial. This is particularly true of marginal energy costs, since this amounts to forecasting the world oil price many years into the future. Multi-year forecasting is required since investment decisions involve marginal cost over a multi-year horizon. This is true for any long term investment. To illustrate the volatility of oil cost projections we contrast two of PG&E's marginal cost estimates, Tables 4-1 and 4-2.

Table 4-1 was an estimate produced in 1980 for PG&E's 1981 General Rate Case (CPUC Appl. No. 60153). It is the sum of the marginal energy cost and the shortage cost. Table 4-2 is a more detailed breakdown of the same concept from the 1983 general rate case. That is, Table 4-2 is two years more recent that Table 4-1. The detail in Table 4-2 indicates that the annual capacity cost is a small part (on the order of 20%) of the total marginal cost. Although the Table 4-1 calculation of shortage cost is somewhat different than Table 4-2 (in ways which will be discussed below) this cost is still a small part of the whole. Therefore the difference between these estimates in the long run reflects changing perceptions of the oil market, since that is almost always the marginal fuel. In 1990 the earlier estimate was 55% above the later, and for 2000 about 45% above.

With this kind of long run price uncertainty, it is difficult to take Fiske's assertions about net resource costs and marginal investment cost literally. It would be an interesting exercise to use Tables 4-1 and 4-2 to value the nearly completed Diablo Canyon project. Clearly the lower marginal costs will diminish this value. Such an exercise would require a capital cost estimate, which is itself uncertain. This would be a controversial analysis.

For rate-making purposes it is not necessary to make long run forecasts of marginal cost, at least with respect to energy. All that is necessary is the short run marginal cost which can be estimated from standard production cost models. The procedure is illustrated graphically below in Figure 4-1. This figure shows when a particular generating unit i is the marginal producer.

In Figure 4-1, we illustrate the use of the inverted load duration curve in production costing. This is the same load representation as in the upper panel of Figure 3-8 only rotated so that minimum loads are represented as Prob (L > minimum) = 1. The energy produced by the i^{th} unit is represented as the hatched region. Baseload units serve below units such as i which here is shown to be on the margin for loads between x_1 and x_2. Since units are "dispatched" in the order of increasing production cost, loads above x_2 will have higher marginal cost than those served by unit i. We can calculate an average marginal cost in this manner by weighting the cost of marginal units such as i by the fraction $\Delta p = p_1 - p_2$ of the time the unit is on the margin. Formally we can write

$$\text{Average MC} = \sum_j C_j \ \Delta p_j , \qquad (4\text{-}6)$$

Table 4-1

ANNUAL MARGINAL COSTS OF EQUIVALENT SUPPLY

Year	Electric (1) (mills/kWh)	Gas (2) (mills/therm)
1981	92.3	637
1982	103.5	739
1983	113.1	820
1984	123.0	910
1985	134.3	1010
1986	147.5	1121
1987	162.2	1245
1988	180.3	1382
1989	197.7	1534
1990	216.5	1702
1991	235.1	1873
1992	254.2	2060
1993	275.4	2266
1994	299.6	2493
1995	307.3	2742
1996	344.6	3016
1997	343.9	3318
1998	385.4	3649
1999	432.8	4014
2000	453.6	4416
	After year 2000, escalated at 8% per year	After year 2000, escalated at 10% per year

(1) From PG&E-16, Chapter 1 workpapers; 1982 marginal cost is the combined cost per kWh of energy and demand at the secondary distribution level.

(2) From PG&E-16, Chapter 2, Table 2-B.

Table 4-2

CALCULATION OF MARGINAL COST OF EQUIVALENT SUPPLY
Societal Perspective
1982-2002

Pacific Gas and Electric Company

Year	ERI	Annual Adjusted Shortage Cost	Annual Transmission & Distribution Cost	Total Annual Capacity ($/kW)	Total Annual Capacity Cost (mills/kWh) (x 1,000)	Marginal Energy Cost Secondary Voltage Level	Annual Marginal Cost of Equivalent Supply (mills/kW)
1982		73.31	103.51	176.82	20.185		
1983		79.17	111.79	190.96	21.799		
1984	.37	31.20	119.06	150.26	17.153	66.45	83.603
1985	.42	37.71	126.80	164.50	18.780	71.64	90.420
1986	.38	36.34	135.04	171.38	19.564	80.01	99.374
1987	.26	26.48	143.82	170.30	19.441	86.26	105.701
1988	.31	33.63	153.17	186.80	21.324	93.61	114.934
1989	.41	47.36	163.12	210.48	24.027	102.30	126.327
1990	.52	63.98	173.73	237.71	27.136	112.79	139.926
1991		131.04	185.02	316.06	36.080	122.56	158.640
1992		139.55	197.04	336.59	38.424	123.74	164.164
1993		147.22	207.88	355.10	40.337	138.30	178.837
1994		155.32	219.31	374.63	42.766	155.40	198.166
1995		163.87	231.38	395.25	45.120	170.69	215.810
1996		172.88	244.10	416.98	47.600	193.84	243.440
1997		182.38	257.53	439.91	50.218	208.08	258.298
1998		192.42	201.69	464.11	52.981	223.75	276.731
1999		203.00	286.64	489.64	55.895	233.28	289.175
2000		214.17	302.40	516.57	58.969	252.85	311.819
2001		225.95	319.03	554.98	62.212	273.95	338.162
2002		238.37	336.58	574.95	65.634	295.32	360.934

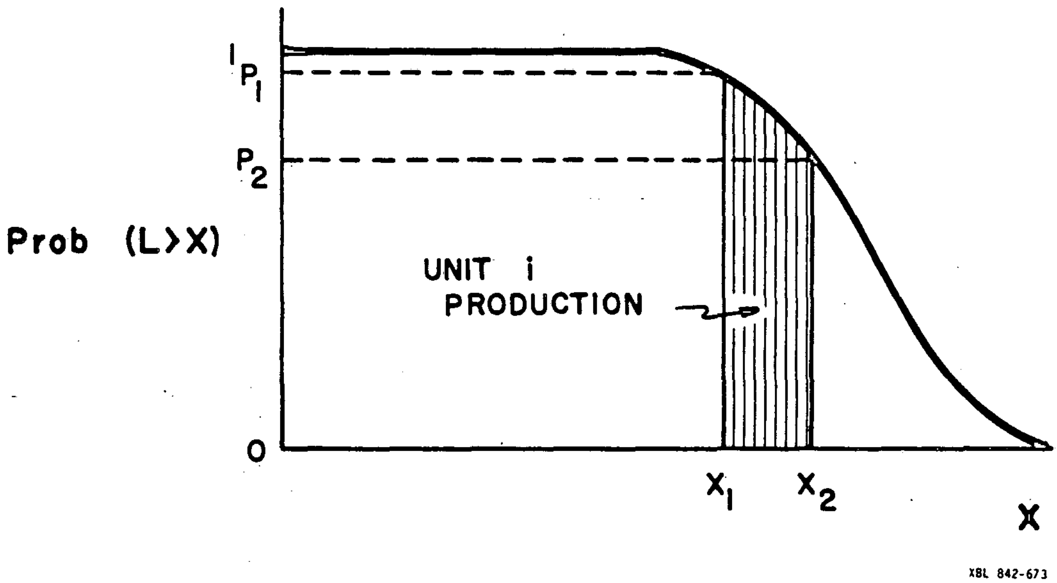

Figure 4-1 Contribution of unit i to marginal energy cost

where

c_j = production cost of the j^{th} marginal unit,

and

P_j = fraction of time the j^{th} unit is on the margin.

It will subsequently become necessary to spread the marginal cost calculated by Eq. (4-6) over the costing periods. This will be discussed later.

Systems with substantial amounts of hydro storage have a characteristic shape to the marginal cost-curve which results from the geometry of Figure 4-2. By convention, the dispatch of storage hydro is used to shave the peak of the load duration curve as illustrated by the horizontally shaded area in Figure 4-2. The resulting change in the shape of the load duration curve creates an unusually large fraction of marginal time for the unit "nearest" the perturbed curve. The corresponding marginal cost curve is shown in Figure 4-3.

Monthly variations in 1990 estimated marginal energy costs are shown in Figure 4-4. Curves are labelled by number of the month and hydro condition (average, A; wet, W; or dry, D).

The next problem is estimating the generation shortage cost. Fiske divides this into the two stages indicated in item (2) of Eq. (4-2). First there must be an engineering characterization of system reliability changes in response to load changes. Secondly there must be a valuation of these reliability changes and the capacity response to them. PG&E proposes a method for measuring reliability changes that extends the ordinary LOLP calculation. The basic idea is to examine the effects of emergency voltage reduction and load-shedding actions that would be necessary in an actual shortage situation. The "effect" measured is the total kWh reduction associated with kW load reductions required by specific emergency procedures. This calculation produces a measure called the Energy Reliability Index (ERI). Formally ERI is defined by

$$\mathrm{ERI} = \Sigma_{ea} \ \mathrm{Prob}(ea_i) \times \Delta \mathrm{KW}\ ea_i, \qquad (4\text{-}7)$$

where

ea = set of all emergency procedures,

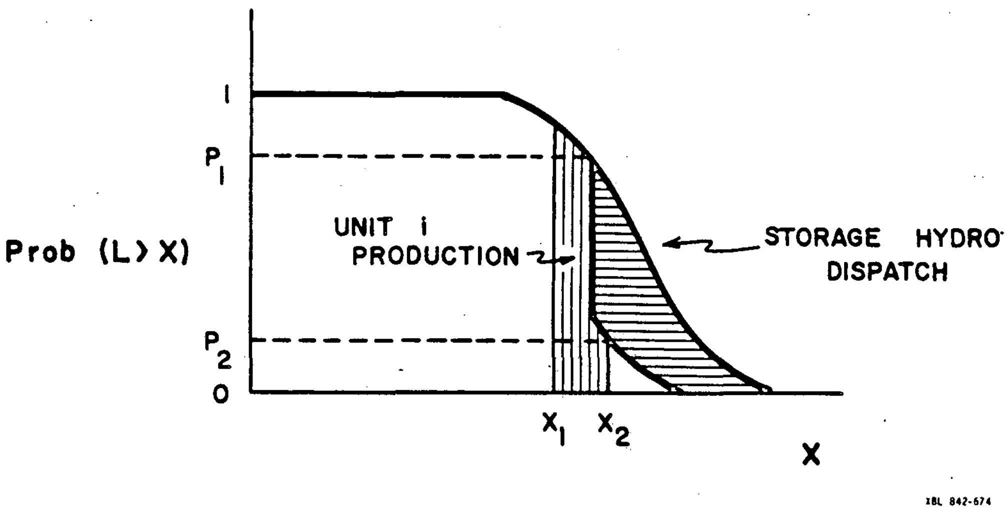

Figure 4-2 Storage hydro dispatch produces a dominant marginal unit

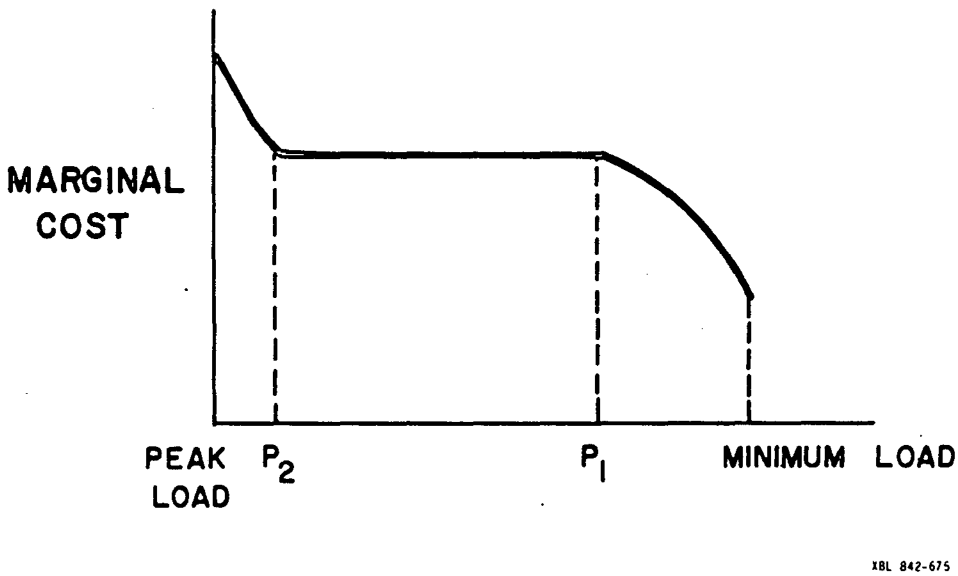

Figure 4-3 Marginal cost curve corresponding to Figure (4-2)

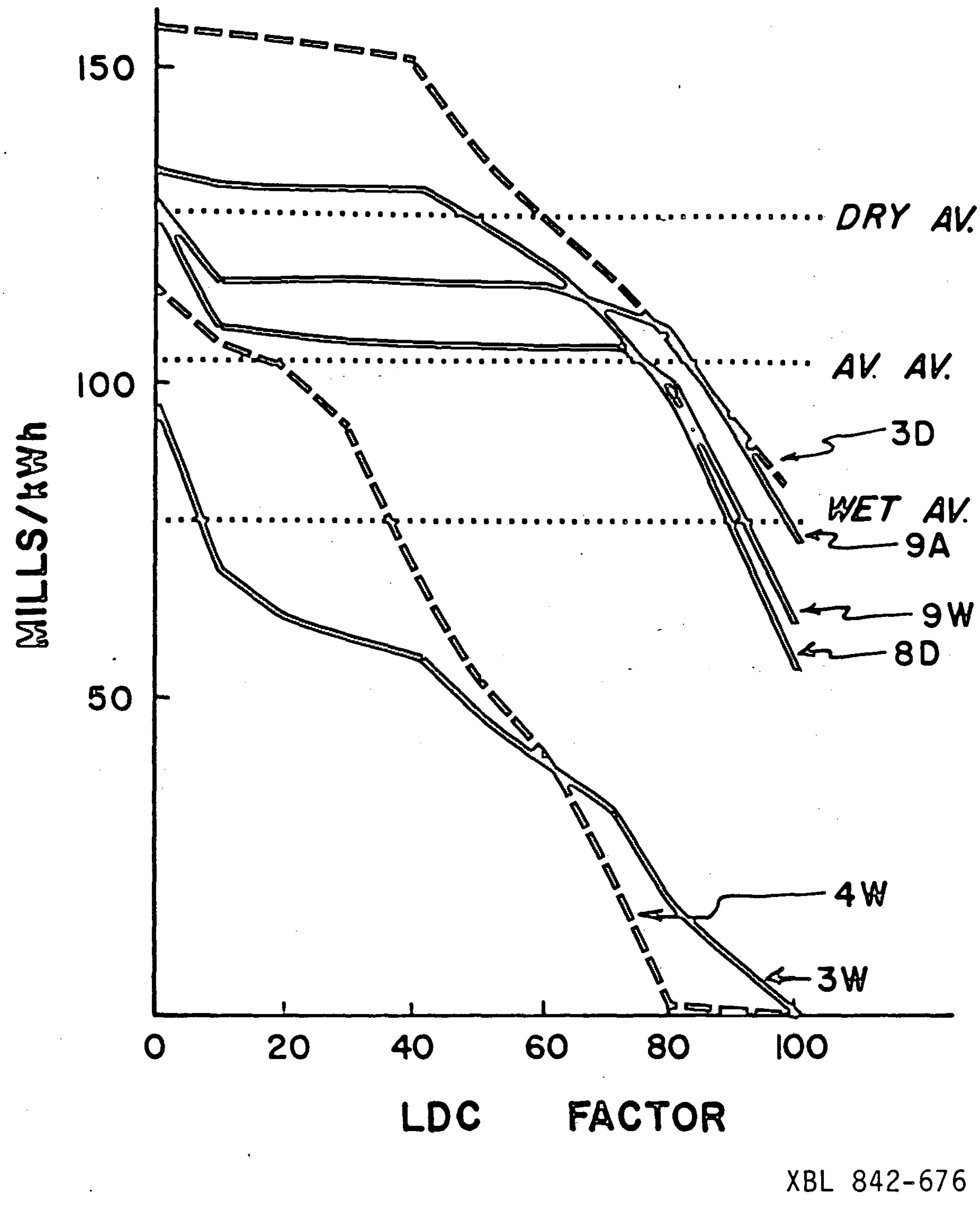

Figure 4-4 1990 monthly marginal cost curves

$\Delta KW\ ea_i$ = load change associated with each ea_i ,

Prob (ea_i) = expected frequency the ea_i will occur.

Notice that Prob (ea_i) is equivalent to a certain number of hours of the year, so that ERI is measured in units of energy (kWh) and not capacity. When the power system is more reliable ERI will be smaller than when it is less reliable. PG&E expects relatively large reserve margins in the next few years with the addition of Helms and Diablo Canyon. ERI will be smaller than the value it would take when LOLP met their version of the one day in ten years criterion. Therefore PG&E argues that the shortage cost must be lower than the standard value associated with years of LOLP equal to one day in ten years.

The valuation of reliability is widely recognized to be a very difficult problem. It basically involves comparison of the utility-functions of all electric customers where the values involved are not all monetized or quantifiable. To simplify this problem California utilities and regulators typically adopt the "gas turbine proxy." Gas turbines are the least expensive capital investment response to increased generation demand. Its capital cost is a proxy for the aggregated social value of reliability. PG&E proposes to discount this proxy cost using changes in the ERI to account for high reliability in the 1984-1990 period. The magnitude of this effect is illustrated in Table 4-2 under the column labelled ERI. For the years 1984-1990 a fraction between .26 and .52 is calculated from estimated changes in the ERI relative to LOLP = 1d/ 10yrs . This fraction is then multiplied by the gas turbine capital cost for a given year to yield the "Adjusted" Shortage Cost.

The methods used for estimating marginal T&D and Customer Costs are qualitatively much cruder than those embodied in Eqs. (4-6) and (4-7). Essentially what is involved is simple one-variable regression equations applied to highly aggregated data. PG&E takes annual changes in T&D demand and fits these to annual expenses for these categories. The slope coefficient of this equation is identified as the marginal cost.

The estimation of marginal distribution costs is complex for several reasons. First, a boundary must be defined between demand-related distribution costs and those which are customer-related. This boundary is essentially arbitrary. It depends upon a concept of a minimum distribution system that is neither motivated intuitively nor derived from engineering principles. Its importance is conceptual; stemming from the need to allocate capital costs to the two intuitively distinct functions. Distribution costs are also separated into primary and secondary levels. These refer to the voltage level at which particular customers take service. Industrial customers, for example, typically take service at the higher voltage primary level. This distinction is made because it will be important for the class allocation stage of rate-making.

4.3 Time Variation of Costs

Having estimated annual total costs (either marginal or average embedded) it is necessary to account for time variation. The first task of this nature is the definition of costing periods. The practical realities of pricing make it necessary to specify a small number of periods for analysis and price (or cost) differentiation. Each period should be relatively homogeneous with respect to its cost characteristics, so that within periods it will be reasonable to average out variations. Since it is useful to have one set of costing periods for all functions, it would be desirable if the periods selected were meaningful for both energy related and demand related costs. This inevitably introduces a little circularity into the definition of relevant time periods.

PG&E illustrates four measures used to define their six costing periods. The measures are (1) daily load curve variation, (2) hourly marginal energy cost, (3) hourly LOLP and (4) excess load probability. Only the last of the measures is unfamiliar. It is not clear why the probability of an hourly load above the mean load (the definition of this measure) is relevant. The figures do show a strong degree of "peaking" around the time interval designated as summer and winter peak. But this as well as the daily load curve partitions is only suggestive rather than conclusive. Of much more importance are the hourly marginal cost and LOLP. These will, in fact, turn out to be the quantities used to allocate costs to time periods. The data presented for "typical" days are instructive.

Examination of the marginal energy cost estimates in Table 4-3 shows reasonable correspondence between changes in hourly loads and changes in cost. But the changes are so smooth and so small (about 30% from high to low) that it is difficult to differentiate any clear boundary that would help define precise costing periods. Hourly LOLP is more conclusive. As we would expect from a nearly exponential function, LOLP is quite volatile. The costing periods defined by PG&E do exhibit substantial jumps in hourly

Table 4-3

HOURLY MARGINAL ENERGY COSTS FOR FOUR TYPICAL DAYS
(Mills/kWh)

Pacific Gas and Electric Company

1984

	SUMMER			WINTER	
Hour	Weekday Average	Weekday Average		Weekday Average	Weekday Average
1	52.29503	51.62204		55.90654	54.59323
2	48.51764	46.65071		52.63513	48.96446
3	45.71657	43.77919		50.58005	46.03802
4	44.71016	41.86613		51.03482	44.95204
5	47.14511	41.49365		55.22331	46.23833
6	53.65974	41.36804		61.88356	49.67982
7	60.63756	44.31091		65.94223	54.89151
8	61.77657	53.79298		67.37842	61.45877
9	61.92087	59.41563		67.81369	64.49452
10	62.20105	60.97075		68.12288	65.44951
11	62.63310	61.36690		68.09425	65.62349
12	62.91519	61.54074		67.83812	65.60156
13	63.45670	61.56273		67.88730	65.08780
14	64.14680	61.56865		67.91809	64.90979
15	64.69347	61.58296	P	67.89246	64.59375
16	64.79115	61.67216		67.72156	64.77602
17	64.72066	61.75868		67.96585	65.98466
18	64.10097	61.75235		68.97305	66.62817
19	63.06891	61.68419	P	69.29492	67.16676
20	62.57907	61.73140		68.57735	66.98016
21	62.57524	61.83720		67.65236	66.50630
22	61.88100	61.64153		66.97398	65.00360
23	61.53511	59.96442		65.21486	62.44556
24	58.78180	53.92987		61.34259	56.56946

LOLP at the boundaries. Table 4-4 shows a summer peak from 12:30 to 6:30 pm, partial peak at 8:30 am to 12:30 pm and 6:30 to 10:30 pm weekdays. All other hours are off-peak. For winter the peak is 4:30 to 8:30 pm. Even in this case, however, it is not entirely obvious why the summer peak is not an hour shorter or the winter peak is not even more narrow. It would appear that the excess load probability offers some support for a "wider" interpretation of the peak period than LOLP alone. The boundary between "partial-peak" and "off-peak" is reasonably well-defined by hourly LOLP, although even here the winter partial peak might end an hour earlier.

Having defined costing periods, PG&E summarizes the hourly LOLP analysis into allocation factors for generation and transmission demand-related costs. These allocation factors are percentages of total annual cost that can be attributed to each costing period. The resulting estimates reflect a somewhat more diffuse distribution of LOLP over the costing periods than the "typical" day tables. For example, the summer (Period A = May 1 to September 30) peak is allocated 68.9% of LOLP, compared to 23.7% for the Period A partial peak. The typical summer week days indicate almost four times the hourly LOLP in the peak compared to the partial peak period. Similarly the summer peak appears to have almost twenty times the LOLP of the winter peak (Period B) in the typical day data. The winter peak is allocated 5% of annual LOLP (this is about 1/14 of the summer peak allocation).

Presumably the detailed PG&E simulations support the final allocation, but precise evidence of this is not offered directly in the testimony. Such technical fine-points are usually settled in the "work papers" underlying quantitative studies. Often these work papers are extensive, and may be computer programs with complex inputs and outputs.

Having allocated costs to time periods, the next task of rate-making is to assign these costs broadly to customer classes. This step is one of the most controversial and difficult.

4.4 Class Allocation of Revenue Requirements

In principle, it ought to be easy to go from costing periods to class allocation. All that is necessary is load research. The main customer classes are assumed to be homogeneous enough so that some sample of their demand characteristics would allow allocation

Table 4-4

HOURLY LOLPS (x 1000) FOR 4 TYPICAL DAYS

Pacific Gas and Electric Company

1984

	SUMMER			WINTER	
Hour	Weekday Average	Weekday Average		Weekday Average	Weekday Average
1	0.00000	0.00000		0.00000	0.00000
2	0.00000	0.00000		0.00000	0.00000
3	0.00000	0.00000		0.00000	0.00000
4	0.00000	0.00000		0.00000	0.00000
5	0.00000	0.00000		0.00000	0.00000
6	0.00000	0.00000		0.00000	0.00000
7	0.00000	0.00000		0.00000	0.00000
8	0.00000	0.00000		0.00001	0.00000
9	0.01242	0.00000		0.00267	0.00000
10	0.05022	0.00000		0.00690	0.00000
11	0.13946	0.00000		0.00521	0.00000
12	0.21379	0.00000		0.00204	0.00000
13	0.35991	0.00000		0.00618	0.00000
14	0.52574	0.00000		0.01090	0.00000
15	0.65216	0.00000	P	0.01507	0.00000
16	0.68659	0.00000		0.01425	0.00000
17	0.66564	0.00001		0.02302	0.00000
18	0.53691	0.00000		0.06623	0.00002
19	0.27291	0.00000	P	0.06903	0.00177
20	0.12200	0.00000		0.03008	0.00002
21	0.15256	0.00000		0.00021	0.00000
22	0.00013	0.00000		0.00000	0.00000
23	0.00000	0.00000		0.00000	0.00000
24	0.00000	0.00000		0.00000	0.00000

of cost. In practice, of course, it is not simple. The difficulties arise in different ways for the marginal cost approach and the average embedded cost or accounting approach. Let us take the marginal cost approach first.

Typically the marginal costs calculated as above, allocated to time periods for energy and demand, then summed with customer costs yield "too large" a revenue requirement. The notion of "too large" is based on some average cost notion of what total revenue requirements ought to be. The discrepancy must be reconciled by some procedure that is not totally arbitrary. It is this reconciliation which creates the problem. The PG&E case provides a concrete setting in which to examine the issue. The magnitudes involved are summarized in Table 4-5 along with the results of using one reconciliation rule.

The left-hand side of Table 4-5 shows that total marginal costs exceed CPUC Revenue Requirements. Only with the exclusion of marginal customer costs can the total revenue requirement be reconciled with marginal cost. The right hand side of the table shows class revenue requirements for residential and industrial customers. The first row shows required revenue scaled so that each class is responsible for the same percentage as their percentage of marginal cost. This is called the Equal Percentage of Marginal Cost Method (EPMC). With customer costs excluded, residential customers are responsible for about 34% of total revenues; industrial customers for about 26%. This is approximately the share of each class in forecast kWh sales.

When marginal customer costs are included, residential customers account for 46% of the total, and the industrial share drops to about 20%. The resulting revenue responsibility using EPMC is shown on the last line of the table. Given the substantial differences in cost allocation, it is important to understand why marginal customer costs should be included or excluded.

At first glance, the exclusion of marginal customer costs seems arbitrary. If the marginal cost perspective is so important, why all of a sudden can one element be neglected? The best answer to this was given by Bonbright who emphasized the arbitrary nature of marginal customer costs. To begin with, these costs were defined with respect to a hypothetical minimum distribution system. However unreal this construct may be, it at least attempts to isolate cost changes which do not respond to demand changes at the margin. Therefore, neglecting them is not important. Even if it were useful to consider

Table 4-5

MARGINAL COST RECONCILIATION AND CLASS ALLOCATION FOR PG&E

	Marginal Cost[a] ($\$10^3$)	Revenue by Class	Residential	Industrial
Energy	1853			
Demand	945	EPMC		
Customer	909	w/o customer	949	734
Total	3707	costs		
CPUC	2867	MC[b]	1713	735
Rev.Req.		percent of total	.462	.198
Marginal Cost w/o Customer Component	2798	EPMC total MC	1324	568

(a) Testimony of R. Howard, EX. PG&E-20, Table 2-3, CPUC Appl. No. 82-12-48.

(b) Marginal Customer Costs x Number of Customers

	MC/Customer	Customer Total
Industrial	\$1048	969
Residential	251	3,044,000

marginal customer costs, there are important network density questions which affect costs. The cost of adding new customers varies substantially with location. New developments such as suburban subdivisions can be expensive. Denser urban sites with networks in place have low marginal customer costs. Instead of reflecting these differences poorly in general rates, it would be better to charge new customers their marginal cost of connecting to the system.

Industrial customers, of course, would prefer the allocation which lowered their rates. In this instance that would make them advocates of full marginal cost allocation. Indeed, marginal cost principles are often invoked by industrial customers to argue for lower rates. This gets tricky in jurisdictions which are more oriented to accounting cost. To understand how commissions reconcile average embedded cost rate-making with the realities of increasing marginal cost, it is instructive to examine demand cost allocation rules in this framework.

In the early and mid 1970's, marginal cost theory supported a rule known as the peak responsibility method for allocating demand related fixed costs. The basic logic, supported with some important reservations by Bonbright, was that peak demand growth drives new investment. Therefore, those classes which contributed most to peak loads should bear capacity costs in proportion to that contribution. It was not uncommon then, and even today, to treat all capacity costs as demand related. This is not really correct, because it fails to account for the investment motivation of capital substitution for fuel. Bonbright argues, for example, that any generation capital costs above those associated with gas turbines should be allocated to energy costs. An equivalent approach is a modern revival of a traditional method known as the Average and Excess Demand (AED) method.

The AED method attempts to allocate fixed demand-related costs (here usually identified with all fixed capacity costs) to customer classes on the basis of class load characteristics. Unlike the peak responsibility method, AED also weighs the average demand, i.e., the class share of total energy requirement. Following its leading exponent, Eugene Coyle, we can write an expression for a customer class share of fixed costs as

$$S_c = LF_c \times PCT\ PK_c + PCT\ PK_c\ (1-LF_{sys}), \qquad (4\text{-}8)$$

where

S_c = share of class C,
LF_c = load factor of class C,
= average demand/coincident peak demand of class c,
$PCT\ PK_c$ = percentage of coincident peak due to class c,
LF_{sys} = load factor of entire utility sytem.

The first term expresses the class share of total kWh sales and the second term expresses the class share in "excess" system kW demand above the system average. Older versions of the AED method, such as those discussed in the NARUC Manual, emphasize class non-coincident peaks, such as those which are used to allocate distribution demand over time periods. Non-coincident peaks are meaningless for generation related demand cost allocation. What matters is the coincidence of class loads with the system peak, because only this affects marginal costs.

The application and effect of Eq. (4-8) is illustrated by an example in Table 4-6. The data is representative of California utilities. This example shows that AED tends to equalize class allocation between residential and industrial customers, compared to coincident peak responsibility. AED in this version has become more popular as the economic rationale for new plant investment has increasingly become more oriented to fuel mix optimization (i.e., oil savings) and not peak load growth.

AED represents a kind of marginalism in the accounting cost framework that industrial customers would tend to oppose since it works against their interest. This is an unusual outcome because usually marginal cost theory favors large users in one way or another. We will return to this theme in the context of Ramsey pricing later on. For current purposes, it is necessary to turn to tariff design proper, that is to the mechanics of constructing rate schedules to produce required revenues allocated to class.

4.5 Unit Cost Tariffs

Unlike simple commodities, electricity is typically priced by a schedule of tariff charges from which a total bill is derived as a function of usage characteristics. There is no one price per unit, but usually more than one applicable price. The basic intent of this multiplicity is to capture the multi-dimensional nature of electric power service. As we have seen, the demand (kW) and energy (kWh) dimensions are the most important cost

Table 4-6

AED VS. PEAK RESPONSIBILITY

Class	PCT PK	LF	Pct kWh	AED Share
Residential	.35	.40	.27	.287
Industrial	.26	.66	.33	.281

System Load Factor = .58

features. It is not surprising therefore that tariffs would be designed to bill each feature separately. The only limitation on such billing is the cost of meters to measure both kW and kWh. This only turns out to be economic for larger customers. For residential customers the relevant load data is often not available in detail. Sometimes summary statistics such as the customer class load factor are used to justify rate design in terms of cost. To illustrate typical rate design problems we will start by examining demand charges for different kinds of large users.

The linkage between demand charges and marginal costs is the notion of a "coincidence factor." Demand charges are based on the maximum demand recorded in a given costing period. These maximum demands may or may not correspond to the actual system peak demand. Furthermore, individual customers cannot be evaluated separately for their degree of coincidence between their maximum demand and that of the system. Therefore rate designers will use a class coincidence factor defined as follows

$$\text{Class Coincidence Factor} = \frac{\text{Class Coincident Peak}}{\text{Total Class Maximum Billing Demand}} \tag{4-9}$$

We illustrate the use of the coincidence factor in detemining marginal cost of generation and transmission demand for industrial customers of PG&E, and compare this to proposed tariff charges in Table 4-7.

Table 4-7 compares marginal generation and transmission cost revenues for PG&E's industrial customers with proposed demand charges. The proposed demand charges are only intended to cover marginal distribution costs for these customers. The rate design neglects the other cost factors in the interest of keeping the demand charges low. The motivation of this tariff design is to avoid the incentive to increased consumption that high demand charges represent. Since the demand charge is based on peak consumption, once it is incurred then there is no dis-incentive to additional off-peak consumption. It is also worth observing that the revenue associated with demand charges is only about 11% of the revenue requirement for industrial customers (compare Table 4-7 with Table 4-5). This corresponds roughly to the marginal cost structure of PG&E where marginal energy costs are the dominant form. Other utilities which are less dependent on oil and gas than PG&E will typically have much larger demand charges for industrial customers. It is not uncommon for these rates to be 3 or even 4 times the $2.80/kw-month level proposed by PG&E.

Table 4-7

MARGINAL GENERATION AND TRANSMISSION COSTS
AND PROPOSED DEMAND CHANGES

PG&E Industrial Customers

Billing Demand[a] (mw)	Period A	Period B	Revenue at $2.80/kW
Sch. A-22	6,777	9,129	$\$44.54 \times 10^6$
Sch. A-23	5,759	7,987	38.49×10^6
	12,536	17,116	$\$83.03 \times 10^6$
Marginal Costs			Total MC Revenue
Average Monthly Demand[b]	2,507	2,445	
Co-incidence Factor[a]	.764	.746	
Co-incident Demand	1,915	1,824	
Marginal Cost[c] ($/kW-Period)	$48.30	$3.78	
MC Revenue	$\$92.49 \times 10^6$	$\$6.89 \times 10^6$	$\$99.38 \times 10^6$

(a) Work papers for Ex. PG&E-20 in CPUC Appl. No. 82-12-48.
(b) Period Billing Demand/Months per Period.
(c) Table I-29, Ex. PG&E-13 (Fiske) at the Primary Dist. Level.

A particularly interesting demand charge tariff is the rate for stand-by power for cogeneration customers. Although the cogenerator produces the major part of his electricity requirement on-site he will need back-up power to supply his needs during forced and scheduled maintenance of his equipment. Rather than incur the cost of complete back-up on-site, it may often be desirable to purchase back-up power from the utility on a stand-by basis. The key issue is the price for this service, which depends upon the load characteristics of back-up customers. The central fact to be determined is the extent of diversity in back-up requirements for cogeneration. It may be argued plausibly that this diversity should be great, and hence coincident demand low. But since the tariff must be set before load data has been gathered, the class coincidence factor is unknown. Table 4-8 shows three estimates of annual demand charge revenues required per kW for stand-by service on the Consolidated Edison system (ConEd).

You will recall that ConEd is opposed to cogeneration development on a number of economic and environmental grounds. It is not surprising that their rate proposal (Monsees, estimate #2) projects the largest revenue requirement. ConEd uses the high embedded costs as its basis for valuing service (same as Arnett). Furthermore ConEd chooses coincidence factors which are identical to those estimated for the customer class (large commercial) from which most cogenerators are expected to come.

The other witnesses testifying on this issue reject the ConEd coincidence factor assumptions. Arnett, who is testifying on behalf of a state agency, proposes coincidence factors of 10%. This is essentially a judgement call based on the intuition of substantial diversity among cogeneration outages. Arnett then applies this assumption to the embedded cost values resulting in revenue requirements that are 58-66% of those prospsed by Monsees of ConEd. Beach is the witness of the PSC Staff. She adopts marginal cost values for each function and zero coincidence for generation and transmission. Notice that ConEd's marginal costs are below average embedded costs. The very small value for generation reflects ConEd's large reserve margin. The resulting estimate is 48-73% of Arnett's.

The New York PSC ended up endorsing Beach on this issue. The evidentiary basis of that decision was weak. The only real evidence offered was an LOLP study done for ConEd by Ebasco Services. The study purported to yield the result assumed by Monsees on coincidence, but only under the unrealistic assumption that all cogenerators should have an LOLP of 10^{-4}.

Table 4-8

STAND-BY DEMAND CHARGES
COST ESTIMATES FOR CONSOLIDATED EDISON

	Cost	Coincidence Factor		Annual Cost	
	$/kW	HV	LV	HV	LV
1. Arnett: Average Embedded Cost					
Production	123.80	0.10	0.10	12.38	12.38
Transmission	34.57	0.10	0.10	3.46	3.46
Primary Dist.	41.09	1.00	0.68	41.09	27.94
Secondary Dist.	32.60	—	1.0	-.-	32.60
Customer Cost	8.80	1.00	1.0	8.80	8.80
				65.70	85.18
2. Monsees					
Production		0.40	0.37	49.52	45.81
Transmission		0.40	0.37	13.83	12.79
Remainder: Same as (1)				113.24	127.94
3. Beach: Marginal Cost					
Production	3.26	0	0		
Transmission	21.00	0	0		
Primary Dist.	32.79	~1	~1	31.56	
Secondary Dist.	31.96	0	~1		62.36

In California, the CPUC has adopted a cogeneration stand-by demand charge of \$0.75/kW-month. This is about 27% of the industrial demand charge and implies a coincidence factor of 20% (= .27 x .75). There has not been a load study on this service since the rate was instituted several years ago. PG&E estimates \$3.8 million in revenue under this rate in 1984.

Load characteristics of smaller customers cannot be typically incorporated in tariffs by using demand charges. The principal reason for this is the high transaction costs associated wtih metering smaller loads. Since load information is available for small users, however, it would be useful to incorporate this into tariff design. It is common to express customer load characteristics by one summary statistic, the coincident load factor. We used this at the class level in the discussion of the AED allocation method. It can also be used at the tariff level to justify the general "shape" or level of the tariffs designed with a class. Generally speaking, high load factors imply lower cost loads. The logic is the same as at the class allocation level. If one subclass of residential customers can be shown to have higher load factors than another, then they ought to have lower rates. One application of this principle is the generally lower price level associated with electric space heating tariffs compared to ordinary residential tariffs. Another application of the principle can be made with regard to the structure of rate; the differential pricing of different blocs of consumption.

In the declining cost era of the utility industry, residential rates often exhibited a "volume discount" in the form of a lower unit price for use above a certain kWh level. The rationale for "declining bloc" rates was usually a scale-economy through growth argument. It did not have much to do with load factors. In the current increasing cost environment, the opposite kind of rate structure has become more popular, an increasing or inverted bloc tariff. Figure 4-5 illustrates a three tier version of this structure. It has been argued that inverted rates, or "lifeline" rate structues as they are sometimes called, are cost justified by load factor considerations. Table 4-9 gives results of one load study supporting this proposition.

The data in Table 4-9 date from 1974-1977, and may not be representative of conditions generally. There is something of a tendency for load factor to decrease as average monthly consumption increases. Air-conditioning, however, seems to be an equally important factor contributing to declining load factor. It is difficult to support a particular tariff structure from data such as this. To understand why rate structures

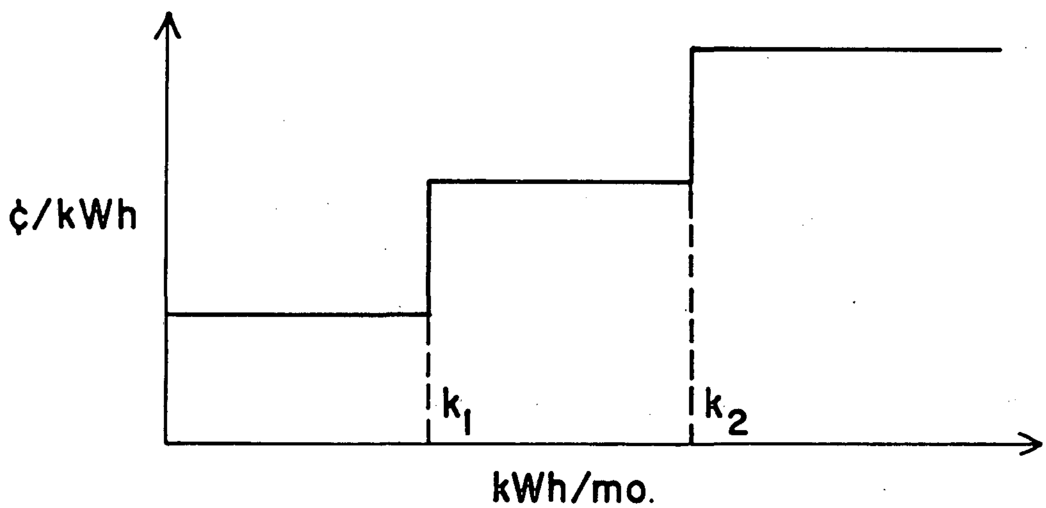

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Figure 4-5 Three tier inverted bloc tariff structure

Table 4-9

AVERAGE MONTHLY SYSTEM LOAD FACTORS

Cincinnati Gas and Electric

Group	Average kWh/month	Average Monthly Load Factor	Summer Average Monthly Load Factor
1 Non Air	329	86.3	100.1
2 Non Air	483	69.5	68.2
3 Non Air	665	72.2	63.8
4 Non Air	1095	76.1	72.2
5 Non Air	2400	66.4	66.1
1 Air	477	65.0	53.4
2 Air	1125	65.0	51.1

such as that illustrated in Figure 4-5 have been adopted and how they are designed requires detailed consideration of particular circumstances. We will concentrate attention on PG&E's current lifeline residential rates, and the on-going process of reform in these tariffs called "baseline" rates.

4.5.1 Lifeline and Baseline Rates: The Case of Pacific Gas and Electric

Residential rates in California assumed the structure shown in Figure 4-5 following implementation by the CPUC of the Miller-Warren Energy Lifeline Act of 1975. There was a substantial political impetus behind the adoption of lifeline rates. A number of political constituencies coalesced behind this kind of rate reform as the optimal response to increases in electricity costs. Essentially the lifeline concept was seen to both promote conservation and reduce the impact of utility rate increases on low income consumers. The first goal appealed to evironmentalists who sought to reduce the need for new power plants. The second goal appealed principally to consumer groups with an interest in income redistribution.

The California Public Utilities Commission was not initially in favor of lifeline rates. Members appointed by Governor Reagan thought that subsidized prices for low levels of energy use were neither justified by cost nor really achieved any income redistribution. Douglas Andersen in his book, Regulatory Politics and Electric Utilities, cites the frank opinions of these commissioners.

> "Lifeline is a fraud. No one gets lifeline because it causes higher rates for business and they pass on more than that cost of business to consumers. Its good for PR and nothing else. They tried to push it as conservation, but that's pure unadulterated b__ s__."
>
> Vernon L. Sturgeon, President, CPUC

A somewhat more philosophical statement of this view was made by Commissioner William Symon, Jr. after a new CPUC majority succeeded in adopting lifeline rates.

"We've become a welfare agency - giving it to people who don't deserve it. We've gotten completely away from the cost-of-service idea. Now its just like throwing darts at the wall."

These expressions of dismay reflect the substantial changes in rate-making procedures brought about by adopting lifeline rates. Because the impetus for the change was political, there were many technical issues to be settled during implementation that had not been given extensive examination before or during the policy debate. We will examine some of these questions with reference to data describing the Pacific Gas and Electric system.

In the discussion which follows we will survey the major PG&E residential tariff schedules in effect during 1982 and 1983. The problem of forecasting revenues under uninverted rates is introduced with reference to the sales frequency distribution data. We then describe a reform of the lifeline rate structure into a somewhat simpler form known as baseline. Since there are so many possible variations on the inverted block rate structure, it has turned out that frequent changes and adjustments are made. It will be useful to understand the mechanics of such changes.

Exploration of these technicalities is useful as more and more utilities are being encouraged to adopt some version of lifeline or inverted rate structure. The California experience in this regard is likely to be repeated. Policy decisions in favor of inverted rates are often made independent of much analysis or even contrary to studies about its income distribution efficiency. Qualitative changes in the rate structure can be thought of just as a social policy choice. This was essentially the position of the CPUC majority which eventually implemented the first decision in 1975. Andersen cites the candid expression of Jim Cherry, legal assistant to Commissioner Leonard Ross who led the pro-lifeline majority.

"People who kept saying, "but lifeline doesn't help the poor," just didn't understand the issue. The issue is: What is the basic amount society can afford to give you and me? I'd keep explaining that, but they'd come right back and ask what it did for the poor. They didn't understand the broad based political support for lifeline without restrictions on income."

In 1975, California was the only state to adopt the inverted rate structure. It remained the sole one adopted for several years. Gradually, however, more and more states adopted some form of inverted rate structure. The 1981 NARUC Survey indicates that 14 states have moved in this direction. One particularly interesting question about inverted rates concerns the price elasticity effects of different tier prices. This can be especially important during the first transition to an inverted structure. In Section 4.5.2 we examine such a case based on data describing Detroit Edison. For now we begin with an overview of the PG&E lifeline tariff schedules.

The lifeline concept is based on a notion of minimum individual needs. These needs are reflected in Tier 1 allowances which vary according to a number of factors. The size of Tier 1 is determined by (a) climate zone, (b) apppliance holdings and (c) special factors such as rate experiments or the need for life-support equipment. If we consider only the first two items, the resulting number of rate schedules is 52. Table 4-10 shows 1982-83 kWh sales for the major PG&E residential tariff schedules. This represents 85-90% of residential consumption for this period. Table 4-10 distinguishes climate zones (T, X, WA, Y and V), air-conditioning sub-zones (A, B and C of zone X) (see Figure 4-6a&b) and appliance holdings (B, C, H, and W). Since there are different allowances for summer and winter consumption, these are also treated separately. The Tier 1 allowances range from 240 to 1550 kWh per month. The size of Tier 2 has been the subject of much dispute in the past. The current rule is that Tier 2 is the lesser of 300 kWh or 2/3 the size of Tier 1.

Forecasting revenue for lifeline tariffs is not a trivial exercise. Total revenue for such a tariff is given by an expression of the form

$$\left(\sum_{i=1}^{3} \text{Price}_i \times \text{Frac}_i\right) \text{Sales} = \text{Revenue}, \tag{4-10}$$

where

Price_i = rate for Tier i,

and

Frac_i = fraction of total sales in Tier i.

The problematic part of Eq. (4-10) is forecasting Frac_i and total sales. These are in fact joint problems. To understand this problem with some degree of concreteness, we will examine a form of billing data known as the sales frequency distribution. It is useful to define the data distribution with care.

Table 4-10

SALES FROM MAJOR RESIDENTIAL ELECTRIC RATE SCHEDULES
5/82 - 4/83

(10^6 kWh)

Climate Zone	Appliance Code		Summer	Winter	Total
T	B		1231	1431	
	C		153	208	
	H		84	145	
	W		45	51	
			1513	1835	3348
X	B		2021	2287	
		A	673	559	
		B	924	852	
		C	558	585	
			4176	4283	8459
	C		142	213	
		A	180	227	
		B	396	562	
		C	102	154	
			820	1156	1976
	H		91	170	
		A	22	27	
		B	29	42	
		C	32	56	
			174	295	469
	W		62	72	
		A	97	95	
		B	122	132	
		C	26	28	
			307	327	634
WA	B		419	304	
	C		26	30	
	H		13	11	
	W		20	18	
			478	363	841
Y	B		19	18	
	C		74	95	
	H		3	4	
	W		24	24	
			120	141	261
V	B		48	63	
	C		14	20	
	H		1	1	
	W		15	19	
			78	103	181

Table 4-10 (continued)

Direct Control					
X	B				
		A	89	81	
		B	53	59	
		C	19	21	
			161	161	322
					16,491

Appliance Codes:

B = Basic
C = Combined space and water heating
H = Space heating only
W = Water heating only

Map of Winter Climate Zones

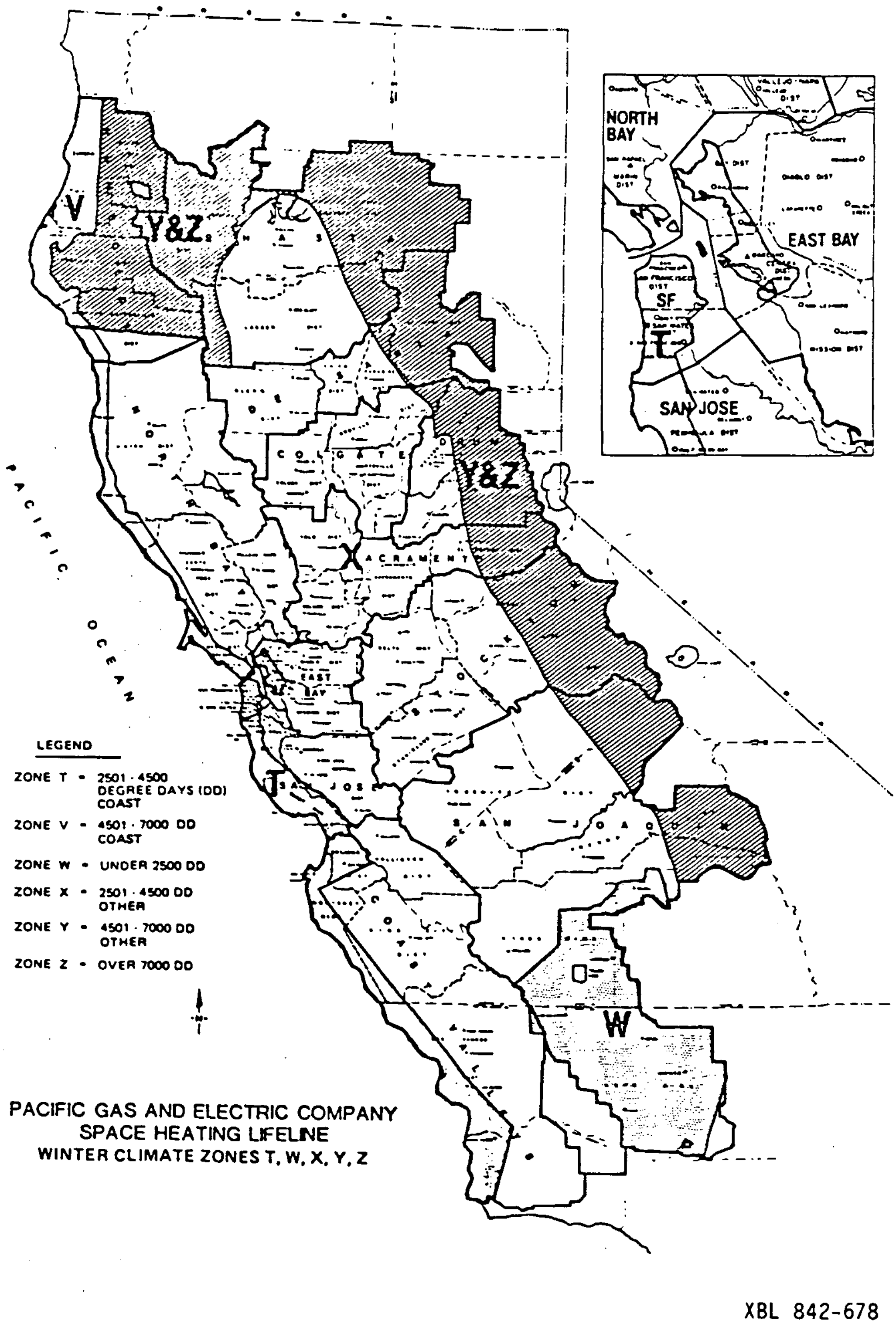

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Figure 4-6a PG&E - present air conditioning and space heating lifeline zones: map of winter climate zones

Map of Summer Climate Zones

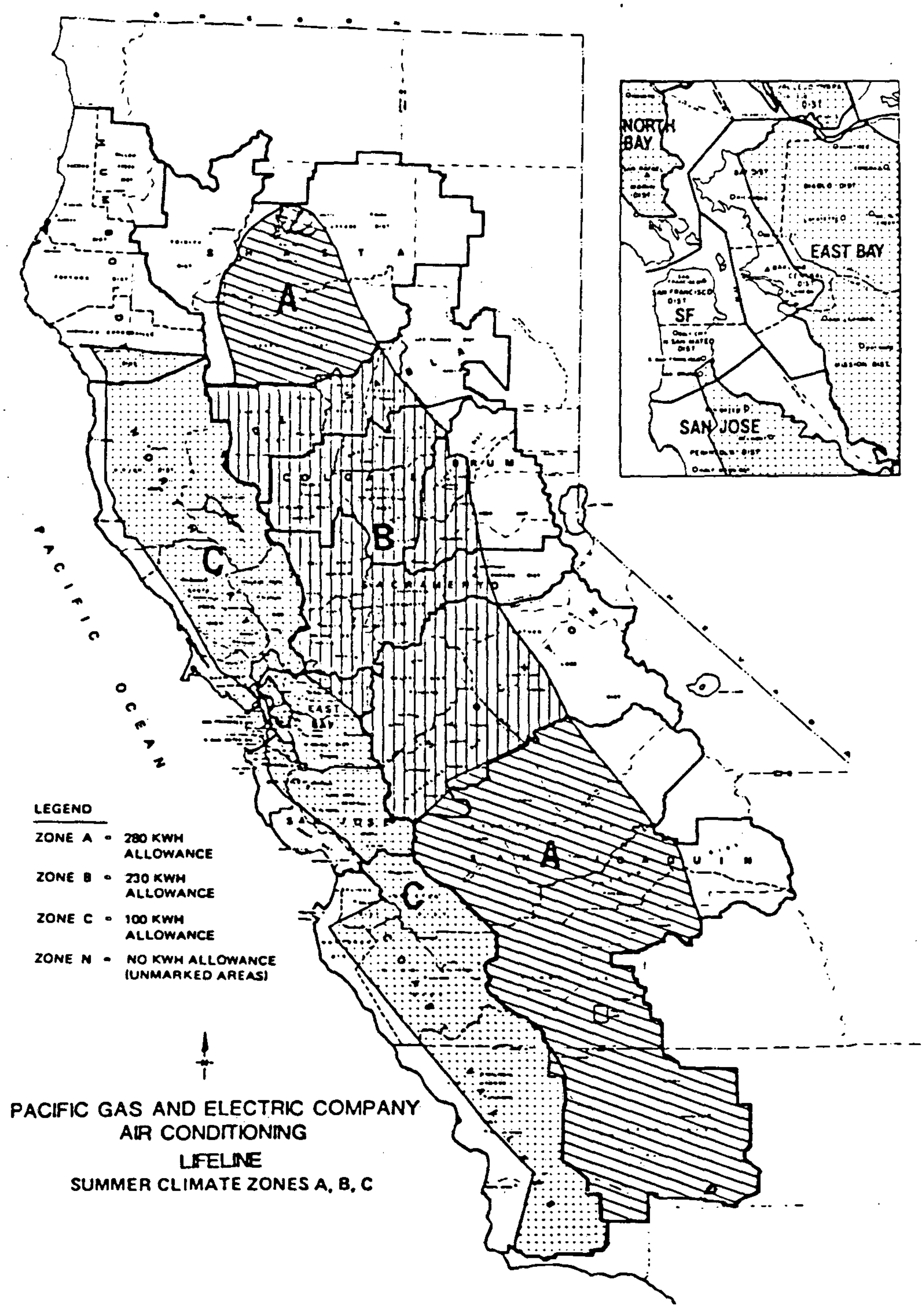

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Figure 4-6b PG&E - present air conditioning and space heating lifeline zones: map of summer climate zones

Let us define for a given tariff class the following quantities:

k_t = the number of bills with sales of at least t kWh/mo,

$\Delta k_{n,t} = k_t - k_{t-n}$ for any integer n,

then

$$\rho\,(\Delta k_{n,t}) = \frac{n \quad \Delta\, kn, t}{\text{Total Sales}} \tag{4-11}$$

The function $\rho(\Delta k_{n,t})$ is a density in the sense of probability theory. It is the fraction of total tariff class sales billed in the n-kWh length interval between t and t-n. Notice that as $t \to \infty$, $k_t \to o$. This means that at higher and higher levels, the number of bills at or above that level goes down. It must go down monotonically because if a bill goes up only to level x, it will have gone to every level below x and none above it. Since $k_t \to 0$, so does $\Delta k_{n,t}$ for any n and therefore both $\Delta k_{n,t}$ and $\rho(\Delta k_{n,t})$ are monotonically declining. Table 4-11 and Figure 4-7 are examples of the function ρ for n = 40 kWh/mo corresponding to the total sales for these tariff schedules identified on Table 4-10 as Climate Zone X, Summer B, Air Conditioning Zones A, B, and C.

The density function ρ defined in Eq. (4-11) is used to define the term $Frac_i$ in Eq. (4-10). This is done simply by transforming the density into a cumulative distribution function. Formally,

$$D_i = \sum_{t=o}^{i} \left(\rho\ (\Delta k_{n,t}) \right). \tag{4-12}$$

Now let t=a and t=b represent the boundary between Tiers 1 and 2 and between Tiers 2 and 3 respectively. Then we define

$$Frac_1 = D_a\,,$$

$$Frac_2 = D_b - D_a\,, \tag{4-13}$$

and

$$Frac_3 = 1 - D_b,$$

where each tier is identified as the appropriately numbered subscript.

Table 4-11

SALES FREQUENCY DENSITY FUNCTIONS
Summer 1982
Pacific Gas and Electric

	IXBS	AIXBS	BIXBS	CIXBS
40	.09300	.06843	.07723	.07294
80	.09170	.06769	.07607	.07255
120	.08870	.06634	.07403	.07162
200	.07921	.06159	.06771	.06767
280	.06701	.05470	.05944	.06116
320	.06046	.05088	.05499	.05721
360	.05383	.04700	.05046	.05301
400	.04733	.04313	.04597	.04858
440	.04105	.03935	.04152	.04407
520	.02981	.03233	.03316	.03512
600	.02095	.02624	.02590	.02796
680	.01442	.02119	.01991	.02043
840	.00684	.01393	.01165	.01138
1000	.00335	.00931	.00690	.00636
1200	.00148	.00575	.00367	.00322
1350	.00078	.00388	.00224	.00188
1550	.00041	.00248	.00129	.00105
Av. kWh	426	576	510	545

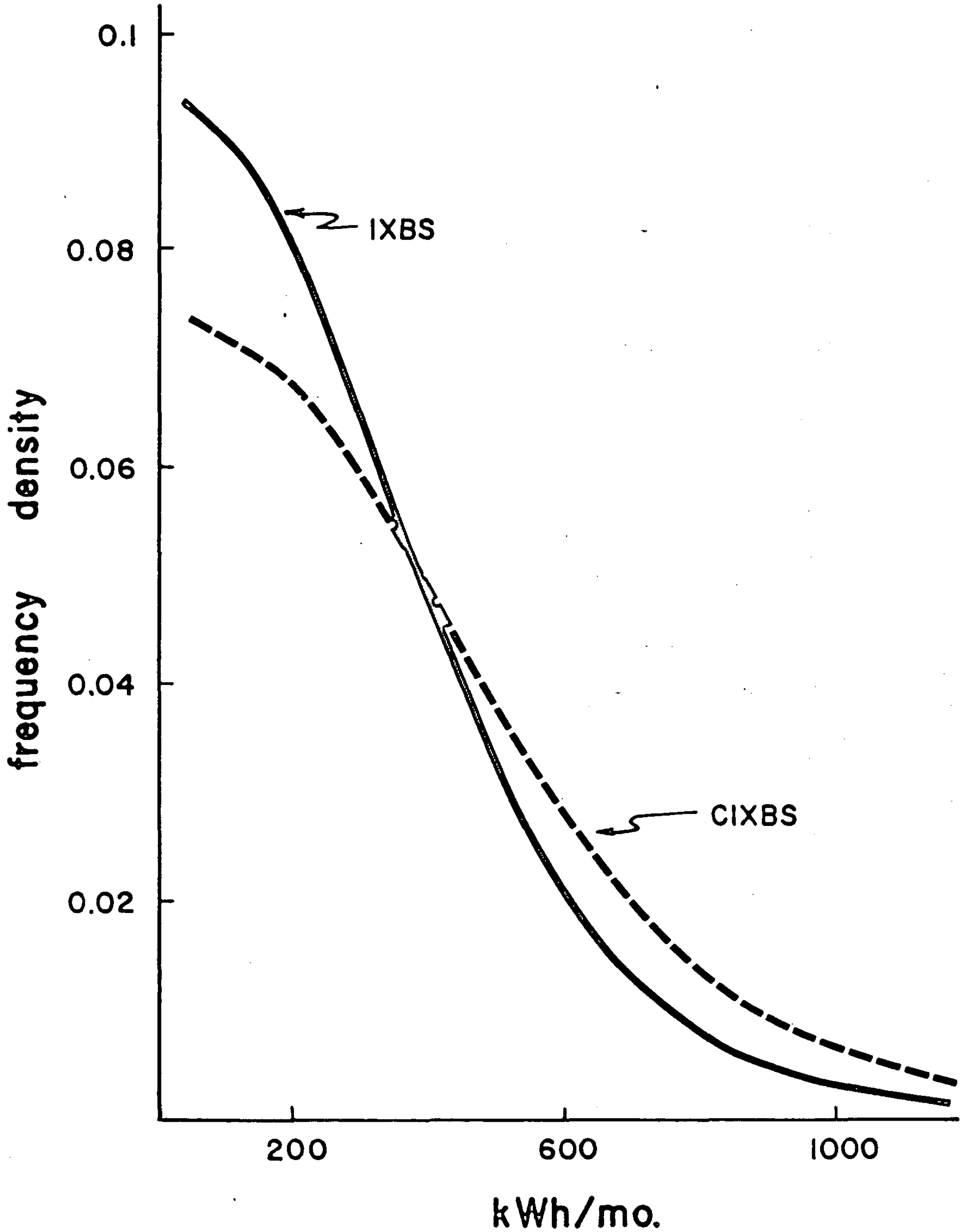

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Figure 4-7 Graph of sales frequency density

In Table 4-12 we give selected values of the function D_i corresponding to the data in Table 4-11 Figure 4-8 is a graph of two tariff schedules represented in Table 4-12.

A basic property of sales frequency distributions is weather sensitivity. Both electricity and natural gas sales exhibit seasonality in their variation. At times of greater climatic extremes, residential consumers use more energy than at other times. The amount of seasonality varies with the climate and the stock of appliances. We can observe weather-sensitivity "cross-sectionally" in Table 4-11. Climate Zone X has hotter and cooler regions. Air-conditioning Zone A, for example, includes Fresno, which averages over 50% more cooling degree days than Sacramento, which is in Air Conditioning Zone B. Table 4-11 shows higher average use in A compared to B (576 vs. 510). This translates into a somewhat different looking shape for the sales frequency density function. In general the relationship illustrated in Figure 4-7 holds. That is, tariff classes with lower average sales have greater intercepts and slopes, but shorter tails than tariff classes with higher average sales.

The practical implications of weather sensitivity involve the time dimension. What conditions represent an appropriate average upon which to base allowances for average or minimal consumption? The 1982 data averages in Tables 4-10, 11, and 12 represent a "cooler" summer than the average of the recent past. Using cooling degree days between the beginning of May and the end of September (PG&E's Period A) we can see the variations for three cities in Climate Zone X in Table 4-13. It is clear from these data that 1982 would not be a reasonable choice for typical climate. 1981 appears to deviate from the average in the opposite direction. It is too hot. Nonetheless, it appears as if PG&E relied upon the 1981 data to set the "baseline" of allowance levels that are being proposed to replace the "lifeline" system of allowances. The work papers to PG&E's testimony on this subject contain some summary statistics on 1981 sales frequency distributions used to develop the baseline quantities. We reproduce some of this data in Table 4-14 along with the proposed baseline quantitites for the tariff zones in question. Among other simplifications associated with "baseline" is the elimination of Tier 3, and the merging of some tariff classes to reduce the number of tariffs.

It is difficult to reconcile the data in Table 4-14 with public statements made about the nature of the baseline concept. The language of AB 2443 speaks to setting the baseline quantity equal to 50-60% of average residential consumption in a given climate zone. The term "average" is ambiguous in this context, because sales frequency distri-

Table 4-12

SALES FREQUENCY CUMULATIVE DISTRIBUTION
Summer 1982
Pacific Gas and Electric

	IXBS	AIXBS	BIXBS	CIXBS
40	.0930	.0684	.0772	.0729
80	.1847	.1361	.1533	.1455
120	.2734	.2025	.2273	.2171
200	.4370	.3284	.3662	.3548
280	.5734	.4414	.4894	.4806
320	.6378	.4923	.5444	.5378
360	.6917	.5393	.5948	.5908
400	.7389	.5824	.6408	.6394
440	.7800	.6217	.6823	.6834
520	.8450	.6898	.7527	.7581
600	.8910	.7452	.8080	.8161
680	.9229	.7900	.8507	.8601
840	.9598	.8556	.9083	.9176
1000	.9776	.8991	.9422	.9496
1200	.9880	.9342	.9611	.9710
1350	.9918	.9512	.9764	.9798
1550	.9948	.9669	.9850	.9869

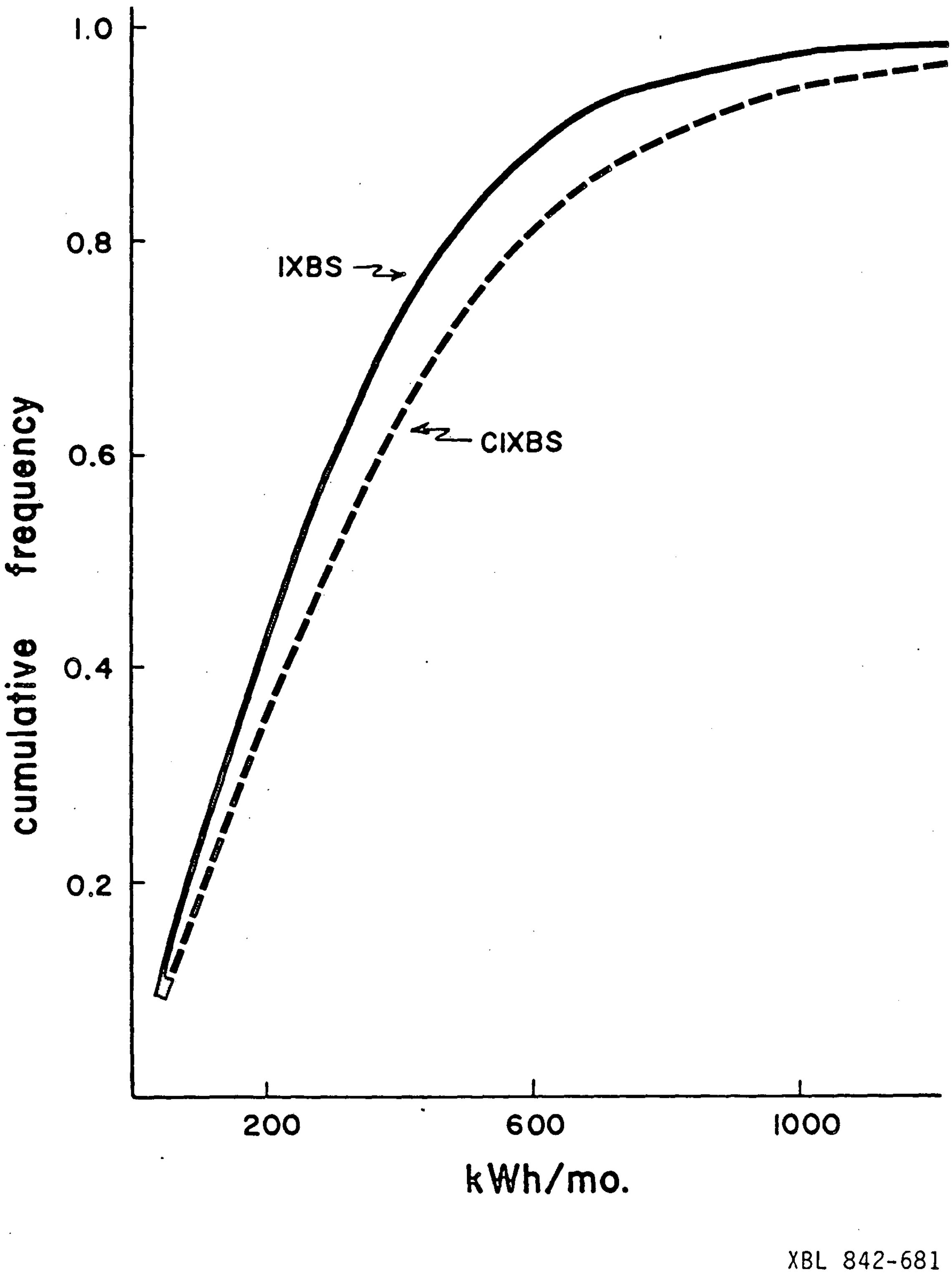

Figure 4-8 Graph of cumulative sales frequency distribution

Table 4–13

COOLING DEGREE DAYS IN CLIMATE ZONE X
May 1 to September 30

City	1982	1981	10 Year Average
Stockton	1161	1685	1440
Sacramento	726	1162	1112
Fresno	1637	2281	1805

Table 4–14

SUMMER 1981 SALES FREQUENCY STATISTICS
Climate Zone X

Tariff Schedule	Climate Zone Mean	Tariff Class Mean (kWh/mo)	55% of Cumulative Tariff Sales	Baseline
1XBS	479	473	305	375
A1XBS	773	712	569	500
B1XBS	709	615	399	500
C1XBS	611	593	356	375

butions are all highly skewed. This property is, in fact, quite nearly invariant in the following sense

Sales Frequency Skewness: The cumulative distribution of sales (D_i) is always approximately (+3%) = .75 at the mean level of consumption. (4-14)

Symmetric frequency distributions all have D_i = .50 for i = mean. In the case of sales frequency distributions there are two possible interpretations of the term "average." It may be understood as the mean of the distribution or its median (the point where D_i = .50). In PG&E's testimony on this subject they interpret the language of the statute to mean that Tier 1 should be set at the level corresponding to 55% of all sales in a given climate zone. This latter definition would appear to require the merging of tariff schedules within a climate zone (B with W and C with H) to produce a distribution from which the baseline amount would be calculated.

It is not clear from Table 4-14 what procedure was used to arrive at the Tier 1 baseline quantities. In some cases they are above 55% of cumulative tariff class sales (BIXBS), in other cases below (AIXBS). Although baseline removes some of the arbitrariness and complexity of lifeline, it does not itself seem perfectly transparent or consistent. Although elimination of the third tier should help utilities estimate revenue more accurately, there will still be problems estimating the fraction of sales in each tier as a function of total sales. One of the principal residual difficulties lies in understanding how price effects associated with relative tier prices affect the distribution of sales. The nature of this problem, which we may call tier-specific price elasticity, will be illustrated with data from another context.

4.5.2 Rate Structure Induced Conservation: The Transition to Lifeline Rate for Detroit Edison

Tier-specific price elasticity can be a particular problem when substantial changes occur in the rate structure. When rates go from a relatively flat structure to a severely inverted one, revenue changes will occur. A recent example of this phenomenon occurred in the transition to lifeline rates in September, 1981, for residential customers of Detroit Edison. The changes in tier sizes and prices are summarized in Table 4-15. The

Table 4-15

RESIDENTIAL TARIFFS
September 1981
Detroit Edison

OLD		NEW		
Block Size	Price	Block Size		Price
		1-2 persons/ household	3+ persons/ household	
(kWh)	(¢/kWh)	(kWh	(kWh)	(¢/kWh)
First 400 kWh	6.31	0-360	0-510	6.045
Next 400 kWh	6.91	360-630	510-810	8.89
Excess	7.61	631 +	811 +	11.82

Detroit Edison lifeline does not distinguish climate variations or appliance holdings. Instead a principal distinction is made between households of 1-2 persons, and those with three or more. These two customer classes are allowed different quantities in Tiers 1 and 2 as indicated in Table 4-15. This partitioning will complicate assessment of the rate structure change and its revenue impact.

We would expect declines in the Tier 2 and 3 sales level, and a slight increase in Tier 1 due to the direction of the price changes. Moreover, the percentage decline should be larger in Tier 3 than Tier 2, since the percentage rate increase is roughly twice that in Tier 2. Quantitative assessment of these changes is difficult, however, because one must estimate what would have happened without the rate structure change. Detroit Edison Company has made such an analysis in an application to recover "lost revenue" due to the introduction of the inverted bloc rates (Michigan Public Service Commission Case No. U-6590-R, May, 1983). We will show how the utility makes this argument using sales frequency distribution data, and a particular method for "adjusting" these data.

The utility's position is summarized in Table 4-16 which shows how actual residential sales were spread over the "old" rate tiers, compared to how they would have been spread (at a higher total) without lifeline. The first step in Detroit Edison's (DE) analysis is to predict the total sales without lifeline. This is done on a use per customer basis, normalizing for weather and other exogenous factors such as regional employment. DE estimates use per customer before lifeline at 492 kWh/month and after lifeline at 476 kWh/mo. This difference times the number of customers produces the 261 million kWh sales loss which appears in Table 4-16. The next problem is to spread these sales estimates over the rate tiers.

DE relies upon the cumulative sales frequency distribution written in the first column of Table 4-17. The average kWh/mo. of this distribution is 495.3. The column labelled "%UPC" indicates what fraction of this average use per customer corresponds to each sales level. To adjust the distribution for a different level of average use per customer the following approximation is used. The original or base sales frequency distribution is retained, but the tier boundaries are adjusted to produce new sales fractions for each tier. The adjustment is made by a proportional change in % UPC, which is then translated into a new cumulative fraction. Formally this procedure amounts to

$$(\%\ \mathrm{UPC})_n = (M_b/M_n)\ (\%\mathrm{UPC})_o, \qquad (4\text{-}15)$$

Table 4-16

ACTUAL VS. ESTIMATED RESIDENTIAL SALES
(10^3 kWh)

Tier	Sales w/Lifeline	$Frac_i$	Sales wo/Lifeline	$Frac_i$
0-400	5,568,481	.6827	5,622,102	.6679
401-800	1,942,665	.2382	2,072,788	.2463
801 +	645,033	.0791	722,205	.0858
Total	8,156,179		8,417,095	

Table 4-17

DETROIT EDISON OGIVE CURVE FOR LIFELINE ANALYSIS

	Cum	% UPC
40	.0798	
80	.1585	
120	.2353	
280	.5084	
320	.5656	
360	.6179	.727
400	.6653	.808
440	.7077	.888
480	.7454	.969
520	.7785	1.050
560	.8073	1.131
600	.8323	1.212
640	.8537	1.292
680	.8722	1.373
720	.8879	1.454
760	.9014	1.535
800	.9129	1.616
840	.9228	1.697
880	.9313	
920	.9386	
960	.9448	
1000	.9503	

and

$$D_n = \mathrm{CUM}\left[(\%\ \mathrm{UPC})_n\right], \tag{4-16}$$

where

M_b = mean use per customer of base sales frequency,

M_n = mean use per customer of the new sales forecast,

$(\%UPC)_o$ = fraction of average use corresponding to the upper boundary of the tier in the base distribution,

$(\%UPC)_n$ = fraction of average use corresponding to the upper boundary of the tier for the new forecast sales level

D_n = cumulative distribution function as defined in Eq. (4-12)

CUM = tabular cumulative function value corresponding to its argument $(\%UPC)_n$.

The logic of this procedure is illustrated by our example. Consider the case in which $M_n < M_b$, i.e., average use declines. We know from considering sales frequency curves that this means that a greater fraction of sales will occur in Tier 1. To represent this increase we raise the upper boundary of the tier as a proxy for shifting the curve. The amount we raise the tier boundary is proportional to the ratio of the base sales frequency mean and the new expected mean. Conversely, when $M_n > M_b$ we want to decrease the Tier 1 fraction which is what Eqs. (4-15) and (4-16) will achieve.

We will now show how Eqs. (4-15) and (4-16) together with the Table 4-17 data are used to produce the Table 4-16 impact estimate of the transition to lifeline rates. DE estimates that average use per customer without lifeline would have been 492 kWh/mo. and that with lifeline this was reduced to 476 kwh/mo. So we will need to adjust tier boundaries with respect to the Table 4-18 base distribution for both cases. The calculation of D_a and D_b for both cases are summarized in Table 4-18.

The result of this procedure is what might be called an equal tier elasticity model. The percentage decline in sales associated with the percentage price increases in Tiers 2 and 3 are about the same. These upper tier elasticities can be approximated by comparing Table 4-15 price changes with Table 4-16 quantity changes. The calculation is only approximate because of the shift in tier boundaries. It is nonetheless instructive. Table 4-19 collects the data and results for all three tiers.

Table 4-18

ADJUSTMENTS OF TIER FRACTIONS

Expected UPC = 492
Ratio (495.3/492) = 1.0067

TIER 1
a = 400

% UPC x Ratio = .808 (1.0067)
= .813
Cum (.813) = $D_{402.6}$

= .6679

TIER 2
o = 800

% UPC x Ratio = 1.616 (1.0067)
= 1.626
Cum (1.626) = D_{805}

= .9142
$Frac_2$ = .9142 - .6679
= .2463

Actual UPC = 476
Ratio (495.3/476) = 1.0405

TIER 1

% UPC x Ratio = .808 (1.0405)
= .840
Cum (.840) = $D_{416.2}$

= .6827

TIER 2

% UPC x Ratio = 1.616 (1.0405)
= 1.681
Cum (1.681) = $D_{832.4}$

= .9209
$Frac_2$ = .9209 - .6827
= .2382

Table 4-19 highlights the anomalous result for Tier 1, that a decline in price corresponds to a decline in consumption. It is not clear if this results from the approximation of tier boundary changes, and so in fact is not true. Alternatively, there may be error in Table 4-17 and/or the adjustment procedure of Eqs. (4-15) and (4-16). At this point, there is not sufficient information to untangle this phenomenon. The results for Tiers 2 and 3 indicate equal tier elasticities. Again it is not clear whether this is a fortuitous outcome, or results from the adjustment procedure (i.e., Eqs. (4-15) and (4-16)).

The importance of this problem is related to the earnings aspect of revenue instability. Uncertain upper tier sales produce a disproportionate uncertainty in revenues when the upper tier price is above the average tariff class rate. This revenue instability can have significant earnings implications if the fixed cost portion of the upper tier price is proportional to that price.

It is evident that there are more questions in this area than there are solid answers. The entire DE analysis rests upon the validity of the sales frequency distribution in Table 4-17. Yet it is entirely possible that the rate structure changes associated with lifeline altered the shape of the distribution. Another alternative is that the adjustment procedure, which represents a common industry practice , is not a valid way to model the complex tier changes. One way to test this would be to work backwards. Tables 4-20 and 4-21 represent DE's current sales frequency distributions for lifeline rates. In principle, the Table 4-17 distribution should be the weighted average of these four distributions, or simply related to such a weighted average. It might be possible to use some kind of inverse elasticity adjustment to aggregate from Tables 4-20 and 4-21 to Table 4-23. Whether Eqs. 4-17 and 4-16 adequate for this or not remains to be seen. It is possible that more sophisticated methods such as those in Kahn and Levy (1982) are necessary.

A final note on the data in the Tables 4-20 and 4-21. These distributions (or "spreads" as they are sometimes called) are samples of DE data designed to "fit" actual revenue collected. Therefore the total kWh indicated is less than the tariff total. To weight the spreads proportionately, all you need to know is total sales, (8,156,179 mWh), total customers (1,426,581) and the fraction of households with 3 or more persons (.46) and 1-2 persons (.54).

Table 4-19

TIER SPECIFIC ELASTICITY

Tier	Price Change	Quantity Change	Elasticity
1	- 4.3%	- 1.0%	+ .23
2	+ 28.6%	+ 6.3%	- .22
3	+ 55.3%	- 11.0%	- .20

Table 4-20

CURRENT DE SPREADS FOR RESIDENTIAL CUSTOMERS
WITH 3 OR MORE PERSONS PER HOUSEHOLD

	Summer (+3)		Winter (+3)	
	Cum.	Density	Cum.	Density
40	.0699	.0699	.0793	.0793
80	.1397	.0698	.1584	.0791
120	.2092	.0695	.2395	.0787
280	.4765	.0640	.5387	.0718
320	.5373	.0608	.6065	.0678
360	.5942	.0569	.6690	.0625
400	.6466	.0524	.7253	.0563
440	.6941	.0475	.7748	.0495
520	.7736	.0372	.8530	.0357
600	.8337	.0278	.9058	.0236
680	.8773	.0200	.9394	.0147
840	.9301	.0100	.9720	.0053
1000	.9569	.0051	.9842	.0021
1200	.9741	.0026	.9905	
1350	.9814		.9930	
1550	.9874		.9950	
Average	570		503	
Total kWh	1368×10^6		1937×10^6	

Table 4-21

CURRENT SPREADS FOR RESIDENTIAL LIFELINE CUSTOMERS
Detroit Edison
1-2 Persons per Household

	Summer (0-2)		Winter (0-2)	
	Cum.	Density	Cum.	Density
40	.1060	.1060	.1053	.1053
80	.2099	.1039	.2084	.1031
120	.3098	.0999	.3079	.0995
280	.6322	.0664	.6365	.0692
320	.6898	.0576	.6970	.0605
360	.7390	.0492	.7492	.0522
400	.7807	.0417	.7934	.0442
440	.8157	.0350	.8304	.0370
520	.8687	.0240	.8857	.0248
600	.9046	.0162	.9217	.0160
680	.9290	.0110	.9447	.0102
840	.9577	.0054	.9693	.0044
1000	.9728	.0030	.9806	.0021
1200	.9832		.9877	
1350	.9878		.9908	
1550	.9917		.9934	
Average	371		374	
Total kWh	965×10^6		1185×10^6	

This completes our suvey of the traditional problems of price regulation. The one remaining tariff-like problem involves the non-traditional concept of avoided cost. Avoided cost concepts involve the pricing arrangements between utilities and small power producers from whom utilities are required to purchase. The special problems associated with these arrangements, and the relation between avoided and marginal costs will be the next subject of our attention.

4.6 Avoided Costs

The concept of avoided cost was introduced formally in the Public Utilities Regulatory Policy Act of 1978 (P.L. 95-617), known as PURPA for short. PURPA requires that state regulatory commissions establish tariffs under which electric utilities will purchase power from certain kinds of private producers known as "Qualifying Facilities" ("QF's"). The principle underlying such tariffs is that consumers will be unaffected by these transactions, i.e., there will be no change in revenue requirements as a result of QF sales. Congress delegated to FERC (the Federal Energy Regulatory Commission) authority to set regulations for the implementation of these principles by the states.

Most of the concepts and issues that are familiar in the context of marginal cost arise in the context of avoided cost. Indeed, avoided cost may be thought of as a specialized subset of marginal cost. Conceptually the relation between the two notions is something like the relation between "if" and "when". Marginal costs are those costs which change <u>when</u> a load change induces a cost change. Avoided costs are those costs which change <u>if</u> a load change induces a cost change. The distinction is clear in the case of T&D costs. While marginal T&D costs clearly exist and can be estimated, (however crudely), no T&D costs are likely to be avoided by small power production. There may be some changes in the utilization of the T&D system as a result of small power purchases, but on the average use cannot be expected to decrease. Therefore there should be no T&D component in avoided cost prices.

Energy costs are clearly avoided by utility purchase of QF power. The relevant cost is the short run marginal energy cost. This is no problem as long as costs are examined on a year-by-year basis and any change in conditions can be corrected by a revised energy value. As we have seen, however, long run expectations about future energy costs are subject to uncertainty and revision (recall Tables 4-1 and 4-2.) This is important to

QF's because they need to have assurances about the future price of their output. PURPA does not require utilities to make binding projections of future avoided costs; only to publish tariffs for current prices. These tariffs, like any other rate, can change as conditions change. The issue of long run energy avoided costs is a complicated one, and is the subject of on-going adjudication before the CPUC. Before examining these issues in detail, it is useful to consider the treatment of avoided generation capacity costs and their translation into QF payments.

The time dimension is inescapable when valuing capacity. The marginal cost study of Fiske assigns an annual dollar value to generation capacity, for example. This value is a function of both the cost of a gas turbine in that year, and the need for capacity (measured by the ERI) in that year. QF's may receive payment for the generation capacity aspect of their output on either an "as-available" basis or on a specified contract term basis. In the former case the capacity is given a time of use allocation according to the relative LOLP (Fiske, Table 1-27). This allocation spreads the annual value over costing periods. Let us calculate the 1984 Period A capcity payment for on-peak delivery on an as-available basis.

$$\text{Period A On Peak as Available Capacity} = \frac{(\$/\text{kW-yr}) \times \text{Allocation Factor}}{\text{On Peak Period A Hours}}$$

$$\frac{(\$31)\ (.689)}{636}, \qquad (4\text{-}17)$$

$$= 3.36¢\ /\ \text{kWh}.$$

California utilities also offer long term capacity contracts. In this case payment is made on a levelized annual cost basis subject to certain performance standards. Let us first focus on the levelized annual capacity value. You will recall from Table 4-2 that PG&E's shortage cost (i.e., capacity value of generation) increases significantly after 1990. To reflect this increase the annual values can be levelized over the term of the contract. As long as the discount rate is the utility's cost of capital, ratepayers will be indifferent to the levelization. Table 4-22 summarizes these calculations. Table 4-23 illustrates the method for one particular circumstance, a ten year contract starting in 1984.

Table 4-22

FIRM CAPACITY PRICE SCHEDULE
(Levelized $/kW year)

Pacific Gas and Electric Company

Operating Date Year	Contract Life																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	20	25	30
1984	28	31	31	30	30	31	34	40	46	50	54	58	61	64	67	77	84	89
1985	34	33	31	31	32	35	43	50	55	59	63	67	70	73	75	86	93	99
1986	33	29	29	32	36	46	53	59	64	69	73	76	79	82	85	95	103	109
1987	24	27	31	37	49	58	65	71	76	80	84	87	90	93	96	107	114	120
1988	30	36	42	58	68	76	82	87	91	95	99	102	105	108	110	121	129	135
1989	43	51	71	82	90	96	101	105	109	112	115	118	121	124	126	137	144	151

Table 4-23

PG&E TEN YEAR LEVELIZED CAPACITY
Contract Price ($/kW)

Year	Shortage Cost	PV (at 13.5%)
84	31	27
5	38	29
6	36	25
7	26	16
8	34	18
9	47	22
90	64	26
1	131	48
2	140	45
3	147	41
		297

Level Cost = CRF (10, 13.5) x ΣPV
= .188 x 297
= $55

The calculations in Table 4-23 use the definition of level cost Eqs. (2-26) and (2-27) and the definition of CRF (Eq. 2-21). The value reported in Table 4-23 differs from Table 4-22 by about 10%.

Once a levelized capacity payment has been determined as a function of project start date and contract length, a payment procedure must be determined. The basic problem is to specify a performance standard which will be sufficient to receive payment. The CPUC has accepted the "80% capacity factor" standard. This means that QF output in a given month must be 80% of its maximum under the contract to receive that month's capacity payment. There are small adjustments to this formula for maintenance. Further there is a bonus for performance above 85% and reductions for less than 80%.

Because levelization involves "overpayments" in the early years of a capacity contract, provision has been made to have the QF refund payments if contract capacity must be reduced. This is only fair to ratepayers who are ultimately the party at risk financially in levelized capacity payments. If "too much" has been paid for QF capacity delivered, the loss does not accrue to utility stockholders who are uninvolved with the transaction. The basic dynamics of this situation are paralleled in the on-going CPUC hearings concerning long-run contracts for energy produced by QF's.

The basis for levelized capacity payments is the gas turbine proxy for the social cost of shortages. The proposed analogy for long term energy contracts is the "coal plant proxy." In this case it is argued that the economic costs of a coal plant are less than the discounted sum of future avoided costs. Formally, the assertion is

$$\text{PV (Coal Busbar Cost)} < \sum_i \text{PV (Avoided Energy Cost}_i) \tag{4-18}$$

Notice that this is similar to the argument used by Fiske to assert that the net resource cost term of Eq.(4-5) is less than zero for a coal plant. Supposing that Eq. (4-18) is satisfied, its importance lies in the different timing of cash flows. Since busbar cost is a levelized (or largely levelized) cost, it will start out at a value above year 1 Avoided Energy Cost, assuming that Avoided Energy Cost increases. But the only way Eq. (4-18) can be true is for Avoided Energy Cost to increase over time.

Now suppose we accept this argument and decide that long term energy contracts should be priced using the coal plant proxy. As with capacity contracts, price should increase monotonically with contract term length. Now suppose a QF contracts under this basis for a 25 year term. If this QF ceases production any time before 25 years, the ratepayers will lose some amount of over-payment. Why is this more serious than the analogous situation with levelized capacity contracts? The answer lies in the larger magnitude of the costs involved, and the relative seriousness of the failure to live up to contract terms.

Let us consider the failure to deliver contract capacity. Such failures do not imply that the QF project has ceased production totally. Instead it may just be that output is not produced at the appropriate time. In this event, the QF will still be receiving energy payments and capacity refunds may be subtracted from that revenue. Furthermore the magnitude of capacity payments relative to avoided energy costs is rather modest. One kilowatt of capacity, operating 60% of the year will generate $262.80 at 5¢/kWh. The corresponding capacity payments up through 1990 are never more than 25% of that number. Therefore the amount at risk to ratepayers is small for capacity compared to energy. Conversely, long term energy contracts based on the coal plant proxy place considerable risk on the ratepayers. This is the reason that the proposal is controversial.

The motivation behind the long run energy contract issue is hard to understand without explicit analysis of QF economics. It is not enough to review the regulatory record on such issues. The more basic questions involve the structure of small power projects and the constraints upon their economic viability. To investigate these issues we must examine the technical properties and financial requirements of such projects.

Bibliographical Note

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California utilities follow a standard marginal cost analysis procedure in their general rate case applications. We use Pacific Gas and Electric Company, Fiske (1982) as an example. The cost basis of demand charges is illustrated in the discussion of standby rates for cogeneration in a famous Consolidated Edison case (Arnett, Beach, Monsees, 1980). Lifeline or inverted block rates for residential consumers are discussed by Nichols (1981) citing load studies of Cincinnati Gas and Electric (1979). California experience is summarized in Howard (1983). Detroit Edison experience is described in Falletich (1983) and Welch (1983).

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Chapter 5

SMALL POWER PRODUCTION

5.1 Introduction

We have had several occasions to mention cogeneration, a small-scale power generation technology (see Sections 3.7 and 4.5), and the related broader issue of avoided cost rates (Section 4.6). In this chapter we will treat small power production in a more systematic manner. To understand this phenomenon we will briefly discuss the history of these technologies and the emergence of the federal law which encourages their development. To illustrate the range of characteristics exhibited by these technologies we explore two examples of their engineering economies, wind turbines and cogeneration. The first is very capital intensive, with very limited operating costs. Other technologies of this kind are small hydro and solar electric conversion. Cogeneration represents technologies with significant operating, i.e., fuel, costs. Geothermal and solid waste combustion are also of this type. The examples we develop are aimed at demonstrating the gap between the principles of avoided and marginal cost developed in Chapter 4 and the realities of financing small power projects.

The passage of PURPA in 1978 marks the re-emergence of small scale electricity production after half a century or more of decline. The growth of electric utilities had been founded on a scale economy strategy which succeeded because "small" technologies could not compete economically. The transition to an increasing cost structure tended to reverse this relationship. Many of the cost factors discussed in Chapter 3 were 'diseconomies" of scale and therefore tended to favor smaller scale technologies. More important in the short-run was the political upheaval in state utility regulation. Utility management came under scrutiny, review and attack over the prudence of planning methods. This political expression of concern about rate increases and their causes created a new kind of regulatory proceeding, the "need for power" review (see American Bar Association, 1981). In hearings of this kind, the political critics of utility management documented the declining productivity of large scale electric generation, in particular, nuclear power. This atmosphere was conducive to policy initiatives favoring increased competition in electricity generation.

PURPA may be seen as an element in the broader social trend toward de-regulation. It is a very limited step in that direction, and more procedural than substantive, but part of the same drama. In essence the basic thesis of de-regulation policies is that competition will minimize consumer costs in the long run. This result follows from efficiency gains. In the case of electric utilities capital cost escalation for new plants was perceived politically as a management weakness. To control these costs, society can introduce competition in a limited way. PURPA uses the "avoided cost" notion and the obligation to purchase as the means of introducing and limiting competition. The law requires utilities to purchase from "Qualifying Facilities" (QF's). Previously there was no such requirement, so a potential producer could only offer without any expection whether a utility would or would not purchase. Furthermore, PURPA exempts QF's from state utility regulation, so there is no limit on their profits. We will see that returns can be very high sometimes for QF's. The primary determinant of QF profits, however, is the price they receive for their production. This is determined within the avoided cost framework already introduced in Section 4.6. The basic fact about avoided cost prices is that they are a tariff. This means they are subject to change and revision like any other tariff. This has substantial consequences for the financing of QF projects. To secure long term finance, QF's need long term contracts with some assurance about prices. Although PURPA allows for this, it does not require it. In our examples we will see different ways in which QF's might obtain price assurance.

There are substantial policy debates about implementing PURPA. Avoided cost is an ambiguous notion subject to different interpretations. QF's argue that they should be treated symmetrically with utilities and get the kind of revenue stream associated with new power plants. But if the intention of PURPA is to introduce competition, shouldn't a different standard apply? If so, how different? These policy issues go straight to the heart of regulation. Is small power being encouraged because there is no longer a natural monopoly on electricity generation? This cannot be true, however, because the QF's want special regulatory treatment to be viable. We will return to these issues in Chapter 7 where the whole notion of natural monopoly and the role of regulation will be examined.

In this chapter we focus on concrete examples. We begin by defining project financing and its relation to small power projects in Section 5.2. A representative wind energy project is illustrated in Section 5.3. This example shows concretely how financial constraints determine the economic viability of a project. The economics of cogeneration are discussed in Section 5.4. In both examples the crucial role played by long run avoided cost becomes apparent. We identify the generic properties of long run avoided cost in Section 5.5.

5.2 Project Finance

To understand the economic structure of small power projects, we must take account of the methods through which they are financed. In most cases this is different from the corporate finance used by utilities and other large corporations. The typical small power project is based upon a project finance structure. Project financing means simply that revenues associated with a project must be sufficient to meet all costs without outside infusion of funds after the initial capitalization. Although this definition may sound similar to what we have been used to in the corporate context, there are important differences. A project undertaken by a corporation need not be immediately profitable in order to be a sound viable investment. Indeed any project with large start-up costs or substantial R & D requirements will not achieve immediate positive cash flow. The continuing losses of such projects must be financed by corporate capital until cash flow becomes positive. Hopefully, in the long run, returns in the later years will more than off-set the early year losses. At least such are the expectations when corporations approve such projects.

Corporate finance requires that there be a decision rule which relates the firm's overall cost of capital to the rate of return on potential projects. This decision rule is typically some multi-year summary statistic such as NPV or IRR. It may or may not involve a cash flow constraint. Project finance, on the other hand, is both rate-of-return and cash flow constrained. Not only must equity investors receive their required return, but they will only contribute to capitalization once. Therefore, revenues must be adequate to meet the project's debt service from the start.

Why is project finance popular if it is more constrained than corporate finance? Why do corporations themselves set up project financed ventures? Some answers to these questions are offered by Wynant (1980). We will first consider project finance from the viewpoint of leverage. Projects which can generate immediate positive cash flow will typically be able to bear more debt (i.e., have a higher debt fraction in total capitalization) than projects which cannot. If there is more cash, you can borrow more money and still be able to pay off the loan. Equity investors like leverage (i.e., more debt) because it magnifies the upside potential. It also increases the financial risk. A small power project can generate substantial cash flow because a market for its output is guaranteed by PURPA. Furthermore if avoided cost payments are likely to be high, then cash flow will look even better.

The second reason for favoring the project finance structure involves taxation. Small power projects can produce substantial tax benefit from investment credits and accelerated depreciation. Renewable resource projects receive additional tax credits. Corporations often cannot make use of these benefits because their effective tax rates are already low. A project finance structure, however, can pass the benefits along to parties who can make use of them. A popular method of doing this is the sale of limited partnerships in project financed small power facilities.

5.3 Wind Energy Example

We examine both aspects of project financing in the context of a particular project based on wind energy conversion. Table 5-1 is a spread-sheet representation of this project which we will discuss in detail. Spreadsheets are the ideal vehicle for studying small power projects, and their use is recommended where feasible.

The project analyzed in Table 5-1 (labelled Floor Price for reasons that will become apparent) is a 75kW wind generator to be sold to an individual limited partner in a California windfarm. The expected output for the site and technology in question is 223,380 kW per year (34% capacity factor). It is anticipated that this output would be sold to Southern California Edison whose 1983 total Avoided Cost would be 6.4¢/kWh for this project (about 5.2¢ energy and 1.2¢ capacity). The expected avoided cost trajectory to the year 2000 is given on line 6 of Table 5-1. Analysis of this project using this avoided cost trajectory and the capitalization and expense structure given in Table 5-1 will reveal that the project is not feasible. This will be shown in Table 5-2. For our purposes now, we will show how the project succeeds (on paper) at a levelized floor price of 8.5¢/kWh. It will be useful to summarize the basic assumptions underlying the analysis with respect to capitalization, expenses and taxation. These are collected in Table 5-3. We will now explain the structure of Table 5-1.

Table 5-1

	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 Floor Price									
2 Year	1983	1984	1985	1986	1987	1988	1989	1990	1991
3 <u>Assumptions</u>									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	6.40	6.60	6.80	7.00	7.40	7.90	8.50	9.00	9.70
7									
8 <u>Income Statement</u>									
9 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
10 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
11									
12									
13 <u>Expenses</u>									
14 O & M	1,429.63	1,474.31	1,518.98	1,563.66	1,653.01	1,764.70	1,898.73	2,010.42	2,166.79
15 Land Rent	714.82	737.15	759.49	781.83	826.51	882.35	949.37	1,005.21	1,083.39
16 Depreciation	18,412.50	27,005.00	25,777.50	25,777.50	25,777.50				
17 Interest	10,885.00	10,322.00	9,680.00	8,949.00	8,115.00	7,164.00	6,080.00	4,844.00	3,436.00
18 Total Expenses	31,441.95	39,538.46	37,735.98	37,071.99	36,372.02	9,811.05	8,928.10	7,859.63	6,686.18
19 Pre-Tax Income	-12,454.65	-20,551.16	-18,748.68	-18,084.69	-17,384.72	9,176.25	10,059.21	11,127.67	12,301.12
20									
21 <u>Pre-Tax Cash Flow</u>									
22 Sources of Funds									
23 Pre-Tax Income + Depreciation	5,957.85	6,453.84	7,028.82	7,692.81	8,392.78	9,176.25	10,059.21	11,127.67	12,301.12
24 Debt Funds	77,750.00								
25 Equity Funds	45,000.00								
26 Total Sources	128,707.85	6,453.84	7,028.82	7,692.81	8,392.78	9,176.25	10,059.21	11,127.67	12,301.12
27									
28 <u>Uses of Funds</u>									
29 Capital Equipment	122,750.00								
30 Interest During Construction									
31 Debt Repayment	4,020.00	4,584.00	5,225.00	5,957.00	6,790.00	7,742.00	8,825.00	10,060.00	11,469.00
32 Total Fixed Uses	126,770.00	4,584.00	5,225.00	5,957.00	6,790.00	7,742.00	8,825.00	10,060.00	11,469.00
33									
34 Funds Available For Dividends	1,937.85	1,869.84	1,803.82	1,735.81	1,602.78	1,434.25	1,234.21	1,067.67	832.12
35									
36 <u>Tax Effect</u>									
37 Pre-Tax Income-Equity	-12,454.65	-20,551.16	-18,748.68	-18,084.69	-17,384.72	9,176.25	10,059.21	11,127.67	12,301.12
38 Income Taxes	-6,227.32	-10,275.58	-9,374.34	-9,042.35	-8,692.36	4,588.12	5,029.60	5,563.84	6,150.56
39 Income Tax Credit	31,250.00								
40 Tax Savings (Liability)	37,477.32	10,275.58	9,374.34	9,042.35	8,692.36	-4,588.12	-5,029.60	-5,563.84	-6,150.56
41 After Tax Net Equity Cash Flow	-5,584.82	12,145.42	11,178.16	10,778.16	10,295.14	-3,153.88	-3,795.40	-4,496.17	-5,318.44
42 Present Value	31,195.07								
43 PV2	13,296.91								
44									
45									
46									
47									

Table 5-1 (continued)

1 Floor Price									
2 Year	1992	1993	1994	1995	1996	1997	1998	1999	2000
3 Assumptions									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	10.40	11.20	12.10	13.00	14.00	15.00	16.50	18.15	19.97
7									
8 Income Statement									
9 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
10 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
11									
12									
13 Expenses									
14 O & M	2,323.15	2,501.86	2,702.90	2,903.94	3,127.32	3,350.70	3,685.77	4,054.35	4,459.78
15 Land Rent	1,161.58	1,250.93	1,351.45	1,451.97	1,563.66	1,675.35	1,842.89	2,027.17	2,229.89
16 Depreciation									
17 Interest	1,830.00								
18 Total Expenses	5,314.73	3,752.78	4,054.35	4,355.91	4,690.98	5,026.05	5,528.66	6,081.52	6,689.67
19 Pre-Tax Income	13,672.57	15,234.52	14,932.95	14,631.39	14,296.32	13,961.25	13,458.65	12,905.78	12,297.63
20									
21 Pre-Tax Cash Flow									
22 Sources of Funds									
23 Pre-Tax Income + Depreciation	13,672.57	15,234.52	14,932.95	14,631.39	14,296.32	13,961.25	13,458.65	12,905.78	12,297.63
24 Debt Funds									
25 Equity Funds									
26 Total Sources	13,672.57	15,234.52	14,932.95	14,631.39	14,296.32	13,961.25	13,458.65	12,905.78	12,297.63
27									
28 Uses of Funds									
29 Capital Equipment									
30 Interest During Construction									
31 Debt Repayment	13,075.00								
32 Total Fixed Uses	13,075.00	0	0	0	0	0	0	0	0
33									
34 Funds Available For Dividends	597.57	15,234.52	14,932.95	14,631.39	14,296.32	13,961.25	13,458.65	12,905.78	12,297.63
35									
36 Tax Effect									
37 Pre-Tax Income-Equity	13,672.57	15,234.52	14,932.95	14,631.39	14,296.32	13,961.25	13,458.65	12,905.78	12,297.63
38 Income Taxes	6,836.29	7,617.26	7,466.48	7,315.70	7,148.16	6,980.63	6,729.32	6,452.89	6,148.81
39 Income Tax Credit									
40 Tax Savings (Liability)	-6,836.29	-7,617.26	-7,466.48	-7,315.70	-7,148.16	-6,980.63	-6,729.32	-6,452.89	-6,148.81
41 After Tax Net Equity Cash Flow	-6,238.71	7,617.26	7,466.48	7,315.70	7,148.16	6,980.63	6,729.32	6,452.89	6,148.81
42 Present Value									
43 PV2									
44									
45									
46									
47									

Table 5-2

1 SCE Avoided Cost Path									
2 Year	1983	1984	1985	1986	1987	1988	1989	1990	1991
3 <u>Assumptions</u>									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	6.40	6.60	6.80	7.00	7.40	7.90	8.50	9.00	9.70
7									
8 <u>Income Statement</u>									
9									
10 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
11 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
12 Revenues - Avoided Costs	14,296.32	14,743.08	15,189.84	15,636.60	16,530.12	17,647.02	18,987.30	20,104.20	21,667.86
13 Tracking Account									
14 Discount Factor	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
15 Discount Revenue	13,867.43	14,300.79	14,734.15	15,167.50	16,034.22	17,117.61	18,417.68	19,501.07	21,017.82
16 Annual Payment - PTA	-5,119.87	-4,686.51	-4,253.16	-3,819.80	-2,953.08	-1,869.69	-569.62	513.77	2,030.52
17									
18 <u>Expenses</u>									
19 O & M	1,429.63	1,474.31	1,518.98	1,563.66	1,653.01	1,764.70	1,898.73	2,010.42	2,166.79
20 Land Rent	714.82	737.15	759.49	781.83	826.51	882.35	949.37	1,005.21	1,083.39
21 Depreciation	18,412.50	27,005.00	25,777.50	25,777.50	25,777.50				
22 Interest	10,885.00	10,322.00	9,680.00	8,949.00	8,115.00	7,164.00	6,080.00	4,844.00	3,436.00
23 Total Expenses	31,441.95	39,538.46	37,735.98	37,071.99	36,372.02	9,811.05	8,928.10	7,859.63	6,686.18
24									
25 Pre-Tax Income	-17,145.63	-24,795.38	-22,546.14	-21,435.39	-19,841.90	7,835.97	10,059.21	12,244.57	14,981.68
26									
27 <u>Pre-Tax Cash Flow</u>									
28 Sources of Funds									
29 Pre-Tax Income + Depreciation	1,266.87	2,209.62	3,231.36	4,342.11	5,935.60	7,835.97	10,059.21	12,244.57	14,981.68
30 Debt Funds	77,750.00								
31 Equity Funds	45,000.00								
32 Total Sources	124,016.87	2,209.62	3,231.36	4,342.11	5,935.60	7,835.97	10,059.21	12,244.57	14,981.68
33									
34 <u>Uses of Funds</u>									
35 Capital Equipment	122,750.00								
36 Interest During Construction									
37 Debt Repayment	4,020.00	4,584.00	5,225.00	5,957.00	6,790.00	7,742.00	8,825.00	10,060.00	11,469.00
38 Total Fixed Uses	126,770.00	4,584.00	5,225.00	5,957.00	6,790.00	7,742.00	8,825.00	10,060.00	11,469.00
39									
40 Funds Available for Dividends	-2,753.13	-2,374.38	-1,993.64	-1,614.89	-854.40	93.97	1,234.21	2,184.57	3,512.68
41									
42 <u>Tax Effect</u>									
43 Pre-Tax Income - Equity	-17,145.63	-24,795.38	-22,546.14	-21,435.39	-19,841.90	7,835.97	10,059.21	12,244.57	14,981.68
44 Income Taxes	-8,572.81	-12,397.69	-11,273.07	-10,717.70	-9,920.95	3,917.98	5,029.60	6,122.29	7,490.84
45 Income Tax Credit	31,250.00								
46 Tax Savings (Liability)	39,822.81	12,397.69	11,273.07	10,717.70	9,920.95	-3,917.98	-5,029.60	-6,122.29	-7,490.84
47									
48 After Tax Net Equity	-7,930.31	10,023.31	9,279.43	9,102.81	9,066.55	-3,824.02	-3,795.40	-3,937.72	-3,978.16
49 Present Value	24,854.72								
50 PV2	9,842.62								
51									

Table 5-2 (continued)

1 SCE Avoided Cost Path									
2 Year	1992	1993	1994	1995	1996	1997	1998	1999	2000
3 <u>Assumptions</u>									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	10.40	11.20	12.10	13.00	14.00	15.00	16.50	18.15	19.97
7									
8 <u>Income Statement</u>									
9									
10 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
11 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
12 Revenues - Avoided Costs	23,231.52	25,018.56	27,028.98	29,039.40	31,273.20	33,507.00	36,857.70	40,543.47	44,597.82
13 Tracking Account									
14 Discount Factor	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
15 Discount Revenue	22,534.57	24,268.00	26,218.11	28,168.22	30,335.00	32,501.79	35,751.97	39,327.17	43,259.88
16 Annual Payment - PTA	3,547.27	5,280.70	7,230.81	9,180.92	11,347.70	13,514.49	16,764.67	20,339.87	24,272.58
17									
18 <u>Expenses</u>									
19 O & M	2,323.15	2,501.86	2,702.90	2,903.94	3,127.32	3,350.70	3,685.77	4,054.35	4,459.78
20 Land Rent	1,161.58	1,250.93	1,351.45	1,451.97	1,563.66	1,675.35	1,842.89	2,027.17	2,229.89
21 Depreciation									
22 Interest	1,830.00								
23 Total Expenses	5,314.73	3,752.78	4,054.35	4,355.91	4,690.98	5,026.05	5,528.66	6,081.52	6,689.67
24									
25 Pre-Tax Income	17,916.79	21,265.78	22,974.63	24,683.49	26,582.22	28,480.95	31,329.05	34,461.95	37,908.14
26									
27 <u>Pre-Tax Cash Flow</u>									
28 Sources of Funds									
29 Pre-Tax Income + Depreciation	17,916.79	21,265.78	22,974.63	24,683.49	26,582.22	28,480.95	31,329.05	34,461.95	37,908.14
30 Debt Funds									
31 Equity Funds									
32 Total Sources	17,916.79	21,265.78	22,974.63	24,683.49	26,582.22	28,480.95	31,329.05	34,461.95	37,908.14
33									
34 <u>Uses of Funds</u>									
35 Capital Equipment									
36 Interest During Construction									
37 Debt Repayment	13,075.00								
38 Total Fixed Uses	13,075.00	0	0	0	0	0	0	0	0
39									
40 Funds Available for Dividends	4,841.79	21,265.78	22,974.63	24,683.49	26,582.22	28,480.95	31,329.05	34,461.95	37,908.14
41									
42 <u>Tax Effect</u>									
43 Pre-Tax Income - Equity	17,916.79	21,265.78	22,974.63	24,683.49	26,582.22	28,480.95	31,329.05	34,461.95	37,908.14
44 Income Taxes	8,958.40	10,632.89	11,487.32	12,341.75	13,291.11	14,240.48	15,664.52	17,230.98	18,954.07
45 Income Tax Credit									
46 Tax Savings (Liability)	-8,958.40	-10,632.89	-11,487.32	-12,341.75	-13,291.11	-14,240.48	-15,664.52	-17,230.98	-18,954.07
47									
48 After Tax Net Equity	-4,116.60	10,632.89	11,487.32	12,341.75	13,291.11	14,240.48	15,664.52	17,230.98	18,954.07
49 Present Value									
50 PV2									
51									

Table 5-3

WIND PROJECT ANALYSIS ASSUMPTIONS

1. Capitalization
   - Debt: 63.3% of Capital
     - 10 Year Amortization, 14% Interest
   - Equity: 36.7% of Capital
     - Expected Return (after taxes) = 30%

2. Expenses
   - O & M/year = 10% of Avoided Cost Revenues
   - Rent/year = 5% of Avoided Cost Revenues

3. Taxation (Federal only)
   - Depreciation = 5 year ACRS
   - Tax Credit = 25%
   - Tax Rate = 50%

Table 5-1 combines in a bare-bones manner the functions of an income statement, sources and uses of funds statement and investors return projection. We assume a constant revenue stream (line 10) based upon the levelized price and expected production. The standard income statement expenses are listed (lines 14-18) and subtracted from payments to yield Pretax Income (line 19). The actual cash flow will differ for several reasons. First, depreciation is only an accounting item (it is added back in on line 23). Second debt repayment is a cash flow requirement but not an income statement expense (it is listed on line 31). Finally capital funds are added to sources of funds (lines 24 and 25) and equipment cost is the primary Year 1 use of funds. The net of sources and uses is Funds Available for Dividends (line 34). This line represents the cash flow constraint on project financing; it must be positive. If it were negative, the project could not meet expenses. In such an event a further cash infusion would be necessary. This amounts to changing the project. If equity funds were increased, for example, the investor's rate of return would go down.

To calculate the return on equity we must consider tax effects because so much of the earnings come as tax benefits. Line 37 is just a copy of line 19. The assumed tax rate is 50%. By convention we assume that negative taxes are the tax savings accruing to investors from the net operating losses generated by the project. Therefore Line 40 Tax Savings (Liabilities) is just the negative of line 38 plus the Year 1 Tax Credits. Line 41 is the After Tax Net Equity Cash Flow. This is given by

$$\begin{aligned} \text{After Tax Net} &= \text{Funds Available for Dividends} + \\ \text{Equity Cash Flow} &\text{Tax Saving} - \text{Equity Funds.} \end{aligned} \tag{5-1}$$

Lines 42 and 43 represent the NPV of the line 41 stream discounted at 15% and 30%, respectively. Since the NPV>0 at 30%, the investor's rate of return requirement of 30% is being met.

Careful examination of line 41 reveals an interesting (troublesome) feature of this project, negative investor returns in Years 6-10. This occurs because there is no longer any depreciation expense to shelter cash flow of the project from taxes, and this cash is needed for debt repayments. The investor then owes taxes but gets no cash in these years. This is just the opposite of Years 1-5, when there is both cash and tax savings.

Is the negative investor earnings in Years 6-10 a threat to the economic feasibility of this project? The answer is probably not. The negative earnings would clearly encourage the investor to sell the project in Year 6 if he could. A more prudent approach would be to set aside some of the earnings from Years 1-5 to cover the deficits. A third alternative would be to abandon the project in Year 6. This alternative would not really provide the investor with any escape. The problem is that in Year 6 there will still be approximately $51,000 of unamortized debt. In all likelihood the investor would be personally liable for this debt, because otherwise he would not have been eligible for the 25% tax credit in Year 1. The IRS requires that investors be "at- risk" for those sums they take credits upon. In this case that means both the debt and equity must ultimately be the responsibility of the investor. The technical term for this is that the debt is of a "recourse" nature; i.e., the tender has recourse to the investor's personal assets to recover his funds.

Project finance is often set up with "non-recourse debt." In this case lenders must be satisfied that project assets will secure the debt or that it is guaranteed by some outside party (such as a government agency). This usually results in a smaller fraction of debt in project captialization. The "at-risk rule" also means that the non-recourse debt fraction of investment does not qualify for tax credits. Project developers must choose a financial structure which optimizes debt, risk and return for the preferences of their investors. The project characterized by Tables 5-1 and 5-3 is relatively high risk and high leverage. Other wind-power projects are structured in a more conservative manner, with correspondingly lower expected returns.

To understand the features of the Floor Price version of our example wind power project, it is useful to examine some variations on the cash flows of Table 5-1. We will concentrate attention on three features: (1) Revenues at Avoided Cost, (2) Longer Term (15 yrs.) Debt, (3) Ratepayer Repayment for Levelized Floor Prices. These first two features are examined in Tables 5-2 and 5-4.

Let us begin with Table 5-2 where project revenues are calculated at SCE's Avoided Cost, and not at the Floor Price. On this basis the project is not feasible because the cash flow constraint is violated. The requirement of positive values for Funds Available for Dividends is not met. Quite simply, the Year One revenues at the Avoided Cost are about $4700 less than at the Floor Price of 8.5¢. This turns $1938 surplus of cash into a $2753 deficit. These cash deficits diminish as Avoided Cost increases. Only by Year 6

Table 5-4

	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 SCE Avoided Cost Path (15 Year Debt)									
2 Year	1983	1984	1985	1986	1987	1988	1989	1990	1991
3 Assumptions									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	6.40	6.60	6.80	7.00	7.40	7.90	8.50	9.00	9.70
7									
8 Income Statement									
9									
10 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
11 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
12 Revenues - Avoided Costs	14,296.32	14,743.08	15,189.84	15,636.60	16,530.12	17,647.02	18,987.30	20,104.20	21,667.86
13 Tracking Account									
14 Discount Factor	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
15 Discount Revenue	13,867.43	14,300.79	14,734.15	15,167.50	16,034.22	17,117.61	18,417.68	19,501.07	21,017.82
16 Annual Payment - PTA	-5,119.87	-4,686.51	-4,253.16	-3,819.80	-2,953.08	-1,869.69	-569.62	513.77	2,030.52
17									
18 Expenses									
19 O & M	1,429.63	1,474.31	1,518.98	1,563.66	1,653.01	1,764.70	1,898.73	2,010.42	2,166.79
20 Land Rent	714.82	737.15	759.49	781.83	826.51	882.35	949.37	1,005.21	1,083.39
21 Depreciation	18,412.50	27,005.00	25,777.50	25,777.50	25,777.50				
22 Interest	10,885.00	10,637.00	10,353.00	10,031.00	9,663.00	9,243.00	8,766.00	8,221.00	7,600.00
23 Total Expenses	31,441.95	39,853.46	38,408.98	38,153.99	37,920.02	11,890.05	11,614.10	11,236.63	10,850.18
24									
25 Pre-Tax Income	-17,145.63	-25,110.38	-23,219.14	-22,517.39	-21,389.90	5,756.97	7,373.21	8,867.57	10,817.68
26									
27 Pre-Tax Cash Flow									
28 Sources of Funds									
29 Pre-Tax Income + Depreciation	1,266.87	1,894.62	2,558.36	3,260.11	4,387.60	5,756.97	7,373.21	8,867.57	10,817.68
30 Debt Funds	77,750.00								
31 Equity Funds	45,000.00								
32 Total Sources	124,016.87	1,894.62	2,558.36	3,260.11	4,387.60	5,756.97	7,373.21	8,867.57	10,817.68
33									
34 Uses of Funds									
35 Capital Equipment	122,750.00								
36 Interest During Construction									
37 Debt Repayment	1,773.00	2,021.00	2,305.00	2,627.00	2,995.00	3,414.00	3,892.00	4,438.00	5,059.00
38 Total Fixed Uses	124,523.00	2,021.00	2,305.00	2,627.00	2,995.00	3,414.00	3,892.00	4,438.00	5,059.00
39									
40 Funds Available for Dividends	-506.13	-126.38	253.36	633.11	1,392.60	2,342.97	3,481.21	4,429.57	5,758.68
41									
42 Tax Effect									
43 Pre-Tax Income - Equity	-17,145.63	-25,110.38	-23,219.14	-22,517.39	-21,389.90	5,756.97	7,373.21	8,867.57	10,817.68
44 Income Taxes	-8,572.81	-12,555.19	-11,609.57	-11,258.70	-10,694.95	2,878.48	3,686.60	4,433.79	5,408.84
45 Income Tax Credit	31,250.00								
46 Tax Savings (Liability)	39,822.81	12,555.19	11,609.57	11,258.70	10,694.95	-2,878.48	-3,686.60	-4,433.79	-5,408.84
47									
48 After Tax Net Equity	-5,683.31	12,428.81	11,862.93	11,891.81	12,087.55	-535.52	-205.40	-4.22	349.84
49 Present Value	31,175.12								
50 PV2	16,615.20								
51									

Table 5-4 (continued)

	1992	1993	1994	1995	1996	1997	1998	1999	2000
1 SCE Avoided Cost Path (15 Year Debt)									
2 Year	1992	1993	1994	1995	1996	1997	1998	1999	2000
3 Assumptions									
4 kWh/yr	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00	223,380.00
5									
6 Avoided Cost	10.40	11.20	12.10	13.00	14.00	15.00	16.50	18.15	19.97
7									
8 Income Statement									
9									
10 Floor Price	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
11 Total Payments	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30	18,987.30
12 Revenues - Avoided Costs	23,231.52	25,018.56	27,028.98	29,039.40	31,273.20	33,507.00	36,857.70	40,543.47	44,597.82
13 Tracking Account									
14 Discount Factor	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
15 Discount Revenue	22,534.57	24,268.00	26,218.11	28,168.22	30,335.00	32,501.79	35,751.97	39,327.17	43,259.88
16 Annual Payment - PTA	3,547.27	5,280.70	7,230.81	9,180.92	11,347.70	13,514.49	16,764.67	20,339.87	24,272.58
17									
18 Expenses									
19 O & M	2,323.15	2,501.86	2,702.90	2,903.94	3,127.32	3,350.70	3,685.77	4,054.35	4,459.78
20 Land Rent	1,161.58	1,250.93	1,351.45	1,451.97	1,563.66	1,675.35	1,842.89	2,027.17	2,229.89
21 Depreciation									
22 Interest	6,891.00	6,084.00	5,164.00	4,114.00	2,918.00	1,555.00			
23 Total Expenses	10,375.73	9,836.78	9,218.35	8,469.91	7,608.98	6,581.05	5,528.66	6,081.52	6,689.67
24									
25 Pre-Tax Income	12,855.79	15,181.78	17,810.63	20,569.49	23,664.22	26,925.95	31,329.05	34,461.95	37,908.14
26									
27 Pre-Tax Cash Flow									
28 Sources of Funds									
29 Pre-Tax Income + Depreciation	12,855.79	15,181.78	17,810.63	20,569.49	23,664.22	26,925.95	31,329.05	34,461.95	37,908.14
30 Debt Funds									
31 Equity Funds									
32 Total Sources	12,855.79	15,181.78	17,810.63	20,569.49	23,664.22	26,925.95	31,329.05	34,461.95	37,908.14
33									
34 Uses of Funds									
35 Capital Equipment									
36 Interest During Construction									
37 Debt Repayment	5,767.00	6,574.00	7,495.00	8,544.00	9,740.00	11,103.00			
38 Total Fixed Uses	5,767.00	6,574.00	7,495.00	8,544.00	9,740.00	11,103.00	0	0	0
39									
40 Funds Available for Dividends	7,088.79	8,607.78	10,315.63	12,025.49	13,924.22	15,822.95	31,329.05	34,461.95	37,908.14
41									
42 Tax Effect									
43 Pre-Tax Income - Equity	12,855.79	15,181.78	17,810.63	20,569.49	23,664.22	26,925.95	31,329.05	34,461.95	37,908.14
44 Income Taxes	6,427.90	7,590.89	8,905.32	10,284.75	11,832.11	13,462.98	15,664.52	17,230.98	18,954.07
45 Income Tax Credit									
46 Tax Savings (Liability)	-6,427.90	-7,590.89	-8,905.32	-10,284.75	-11,832.11	-13,462.98	-15,664.52	-17,230.98	-18,954.07
47									
48 After Tax Net Equity	660.90	1,016.89	1,410.32	1,740.75	2,092.11	2,359.98	15,664.52	17,230.98	18,954.07
49 Present Value									
50 PV2									
51									

(1988) does cash flow become positive. In the meantime $9590 in cash deficit has been accumulated. For the project to be feasible there must be additional capital to finance this six-year projected deficit. This capital must be raised at the start of the project, thereby increasing its initial cost and reducing investor returns. Notice that if the entire projected deficit were raised with equity funds, and there were no tax credits for these funds, then the present value of equity returns for the year 2000 at 30% would be almost zero ($9843 -9590 = $253). Thus even additional capitalization may diminish returns so much, that investors would not be able to earn the cost of capital.

Let us compare this to Table 5-4 in which the project obtains 15 year debt instead of 10 year debt. The difference in annual payments at 14% interest is $2247. This is almost enough to eliminate the Year 1 cash deficit. In Table 5-4 this is now only $506. The total cash deficit is only $632 and ends in Year 3. Financing an additional $632 out of equity funds would not cause any major change in equity returns. The present value of the equity returns at 30% to the Year 2000 would go down to $15,983 (= 16,615-632). This is still substantially better than the Floor Price value of $13,297. It is clear that with 15 year debt and Avoided Cost the project is both feasible and more attractive than a Floor Price version with 10 year debt. Why then not do it this way?

There are several answers to this question. First and foremost is that lenders will not loan to such projects for 15 years. This is a phenomenon that is not unique to wind power or other small energy projects. It represents part of a re-structuring of the debt markets in general away from long term fixed interest securities and toward variable rates or much shorter debt maturities. One major effect of prolonged and unanticipated inflation is an erosion of the value of long term fixed rate debt. While borrowers gain from this, creditors lose. To protect themselves against such losses, lenders have been reducing their risk by limiting the term of loans or indexing interest rates or both. This tends to make investment in long lived assets less attractive because the financing of such assets does not match their economic lifetimes, or is not predictable.

Even if longer term debt were available in principle, it is not clear that small power projects could obtain financing under avoided cost tariffs. There is still a predictability problem for future Avoided Cost. Even if today's Avoided Cost were enough to meet debt service, what is to say that it won't go down in the future? Lenders need assurances about project revenues over the whole term of the loan. Where avoided cost is based upon oil and gas prices, there is no guarantee that these will not decrease.

There is also another series of influences on Avoided Cost apart from fuel prices, these affect the efficiency of electricity production. Recall that the energy portion of avoided cost is calculated as follows

$$\underset{(\$/\text{kWh})}{\text{Avoided Energy Cost}} = \text{Fuel Cost } (\$/\text{Btu}) \times \text{Heat Rate } (\text{Btu/kWh}) \tag{5-2}$$

Several factors can cause the efficiency to improve, i.e., the Heat Rate to go down. These include increased hydroelectric generation and baseload generation additions. Both such changes cause increasingly efficient units to become the marginal producer of electricity. PG&E, for example, anticipates at least a 10% decline in the marginal heat rate when the Diablo Canyon units are in full operation. Imported power from the Pacific Northwest could reduce the marginal heat rate still further. Even where 10 year debt is concerned, lenders do not want to take these risks. Therefore QF's seek some kind of assurance in long term levelized energy contracts that the price will not go below a certain value. Thus some kind of price floor is an essential feature of energy contacts for QF's, and involves some regulatory complexity.

The basic problem with levelized floor price contracts is that premature project termination may result in ratepayer losses. The QF gets paid above avoided cost with a levelized floor price for some period of time. In return the QF accepts a price below avoided cost to "pay back" the overpayment. Figure 5-1 illustrates this process. From t=o to t=t*, the QF is overpaid. After t*, the ratepayer benefits by paying less than Avoided Cost. If the project terminates before t*, the ratepayer clearly loses. Even if the QF produces after t*, the amount of time required to pay back the excess payments made before t* may be long. Project termination before "repayment" is another ratepayer risk. The problem for regulators is to balance these risks and find suitable pricing formulas to achieve this balance.

The difficulty of the task is substantial. To begin with, we need to define "paying back" more precisely. Operationally we are looking for a time t_e when the levelizing period ends such that the present value of overpayments equals the present value of underpayments. Formally

$$PV \left(\sum_{i=o}^{t^*} \text{Floor Price} - \text{Avoided Cost}_i \right) = \tag{5-3}$$

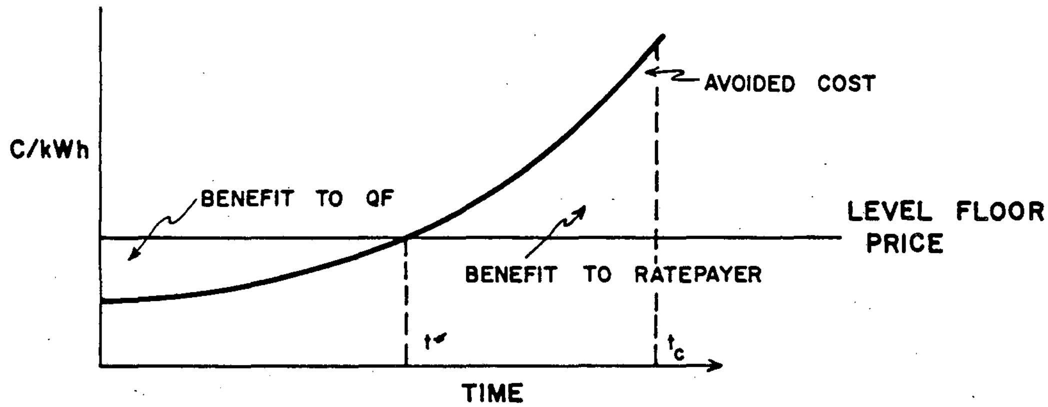

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Figure 5-1 QF accepts price below avoided cost to "pay back" the over payment

$$PV\left(\sum_{i=t^*}^{t_e} \text{Avoided Cost}_i - \text{Floor Price}\right)$$

We cannot specify t^* and t_e in advance because we do not know what the Avoided Cost trajectory will be. We can, of course, make a forecast of the future Avoided Cost, but there is a large probability that it will be wrong.

Even if we find a rule that will satisfy Eq. (5-3) under most outcomes, there is a further issue. In agreeing to level floor price contracts, ratepayers undertook risk. Shouldn't there be some continuing benefit as compensation for this risk? The typical proposal for such compensation involves discount formulas on Avoided Cost. That is, the ratepayer does not pay full Avoided Cost in the long run to QF's seeking levelized floor price contracts. There are a variety of ways in which Avoided Cost discounts can be structured in proportion to the terms of levelized floor price contracts. In Tables 5-2 and 5-4 we indicate one such device known as the Payment Tracking Account (PTA).

Some record must be kept of over and under payments, and a rule developed for determining when repayment has occurred. The issues involved in fixing such a rule include whether Avoided Cost should be discounted, if so by how much, and whether interest should be paid on the unamortized PTA balance. All of these factors will affect the size of the PTA and therefore when it will zero out. There are a number of possible variations on this theme. Perhaps the most difficult issue is determining the size of Avoided Cost discount which should be specified for a given floor price. The example in Tables 5-2 and 5-4 is an instance of the "10 to 1" rule which has been suggested by small power producers (Weisenmiller, 1983). The idea is to discount Avoided Cost by 1% for every 10% the levelized price is above the Year One Avoided Cost. In this case, the 8.5¢ price is about 33% above the 6.4¢ Avoided Cost in 1983; thus the discount is set at 3%. In fact, the "10 to 1" rule has not been widely accepted, but then neither has any other formula been accepted for this purpose.

The PTA mechanism involves another substantial uncertainty that limits its applicability. PG&E has said that the tax status of the PTA has not been resolved. It may not be construed by the IRS as a deductible business expense, and instead may be characterized as a loan to the QF. In some ways, of course, it is a loan. Until the tax status of the PTA is resolved, PG&E wants QF's receiving new PTA contracts to assume PG&E's tax liability regarding this issue. Understandably, QF's are reluctant to do this, so no new agreements are likely to be negotiated. Existing PTA's are not affected.

5.4 Cogeneration

There are currently other proposals aimed at providing long term price assurance to QF's. Some are variations on the levelized floor price idea. One other is designed specifically for cogeneration projects. This proposal is a heat rate floor, instead of a price floor. To see why this would help cogenerators, we must examine the economics of such projects more closely. The discussion of Joskow and Jones (1982) is instructive generally on this subject. We will follow their exposition.

Cogeneration is a joint production process, in which fuel is burned to produce both heat and power. To characterize the efficiency of electricity production by cogenerators, it is convenient to define the net electrical heat rate N. This can be derived from a fuel use identity such as

$$T_c = T_b + (EN/10^6) \qquad (5\text{-}4)$$

where

T_c = total heat rate of the cogenerator (Btu fuel/Btu usable heat),
T_b = total heat rate of the conventional boiler alternative (Btu fuel/Btu usable heat),
E = electricity production rate (kWh/10^6 Btu heat),
N = net electrical heat rate (Btu/kWh).

Eq. (5-4) says that the total fuel consumption of the cogenerator can be split into the "boiler only" equivalent usage rate T_b and a residual term allocated to electricity production at rate E. Eq. (5-4) can be re-written to give a definition of N as follows

$$N = \frac{(T_c - T_b)\ 10^6}{E} \qquad (5\text{-}5)$$

Eq. (5-5) implicitly assumes a constant rate of operation (by assuming E, T_c and T_b are constant). Therefore the values of N given in Joskow and Jones (~4000 - ~7000 Btu/kWh) represent upper bounds on the efficiency of various cogeneration technologies. When load variations and operating strategies are considered, the net electric heat rates are higher (i.e., efficiency is lower). Merrill's characterization is more representative of actual average values for N, ranging from 6000 to 8800 Btu/kWh. By comparison, the average heat rate for utility thermal power is around 10,000 Btu/kWh.

The viability of any particular cogeneration project depends upon the trade-off between the variable cost savings, S, and the incremental capital costs ΔK. It is the savings term S which requires the most analysis. This may be expressed as follows

$$S = V_b - V_c + V_e , \tag{5-6}$$

where

V_b = operating cost of conventional boiler (per 10^6 Btu usable heat),

V_c = cogeneration operating cost (per 10^6 Btu usable heat),

and

V_e = E P_e where P_e = value of electricity per kWh.

Since V_c V_b, it is the "electricity credit" V_e which determines the size of S. We can rewrite Eq. (5-6) in terms of heat rates and fuel prices in the form

$$S = P_b^f T_b - P_c^f T_c + P_e E \tag{5-7}$$

where

P_b^f = price of boiler fuel ($/$10^6$ Btu),

and

$Pf_c{}^b$ = price of cogeneration fuel.

Using Eqs. (5-5) and (5-7) we can write

$$S = E\left[P_e - N\left(\frac{P_c f}{10^6}\right) + T_b\left(P_b^f - P_c^f\right)\right]. \tag{5-8}$$

The second term in Eq. (5-8) only contributes to S if the cogeneration system uses a different fuel than the conventional boiler. This term will be negative if the cogeneration fuel is more expensive than the conventional boiler fuel (say gas vs. coal). In some cases, the cogeneration fuel may be less expensive than the conventional boiler fuel (if it were biomass, for example). In this case the second term is positive. Typically the fuels will be the same, so savings are all due to the electricity term. Let us expand P_e in Eq. (5-8) using Eg. (5-2) for Avoided Cost and assume $P_b^f = P_c^f$. Then we can write with a suitable change of units

$$S = E\left[HR_u\, P_u^f - N\, P_c^f\right] , \qquad (5\text{-}9)$$

where

HR_u = utility's average incremental heat rate (Btu/kWh),

and

P_u^f = price of utility fuel.

Eq. (5-9) illustrates that S depends only on E, and HR_u - N in the case where $P_u^f = P_c^f$. It is unlikely that $P_c^f > P_u^f$ by any large amount. If the cogenerator used much more expensive fuel than the utility, he would need an enormous efficiency differential, HR_u - N, to compensate. On the other hand $P_c^f < P_u^f$, is more plausible. Examples would be coal or biomass cogeneration where the utility burns oil and gas. By far the most typical case will be $P_u^f = P_c^f$. In this case Eq. (5-9) becomes

$$S = EP^f\left[HR_u - N\right]. \qquad (5\text{-}10)$$

Eq. (5-10) illustrates that co-generation projects depend critically on their heat rate advantage over utility generation. The difficulty with the relations given in this equation is that none of the quantities involved are really constants. We have seen that HR_u depends upon the supply mix of the utility and the balance between supply and demand. Obviously the fuel price P^f can fluctuate. The problem of designing a cogeneration system is choosing a technology and capacity level which optimizes savings compared to capital costs. For a given choice of technology and capacity, there will be fixed values of E and N. The subtle dependences involve capital cost scale economies and the variations of heat demand. The optimal sizing trade-off can be analyzed by a simple representation of the heat load variation, the now familiar load duration curve.

Figure 5-2 plots steam load versus load duration. Denoting steam load by C and number of hours by Y, then Y = L(C) is the number of hours per year that steam load is at or above the level C. The total steam supplied (TSS) by a cogeneration system of capacity C_i then is given by

$$TSS = \int_{o}^{c_i} L(s)ds \, . \tag{5-11}$$

It is usually economic to size cogeneration systems at some level above the minimum load C_{min}. In this case TSS $< C_i \times H$. To account for this difference in the definition of net heat rate N (Eq. (5-5)) we write the expressions for total heat rates T_b and T_c in terms of TSS, i.e.,

$$T_c = \frac{\text{Fuel Input}_c}{TSS} \, , \tag{5-12}$$

and

$$T_b = \frac{\text{Fuel Input}_b}{TSS} \, .$$

Then Eq. (5-5) becomes

$$N = \frac{\Delta \text{Fuel} \ (10^6)}{TSS \quad E} \, . \tag{5-13}$$

Compared to Eq. (5-5), the net heat rate defined in Eq. (5-13) for $C_i > C_{min}$ will always be greater than the value for $C_i \leqslant C_{min}$. This follows from TSS $< C_i \times H$; i.e., you are wasting some fuel by not supplying steam continuously.

We can use Eq. (5-13) in Eq. (5-8) to express the savings term with variable steam loads. Again neglecting the second term of Eq. (5-8) we get

$$S = EP_e - \frac{\Delta \text{Fuel}}{TSS} \quad P^f \, . \tag{5-14}$$

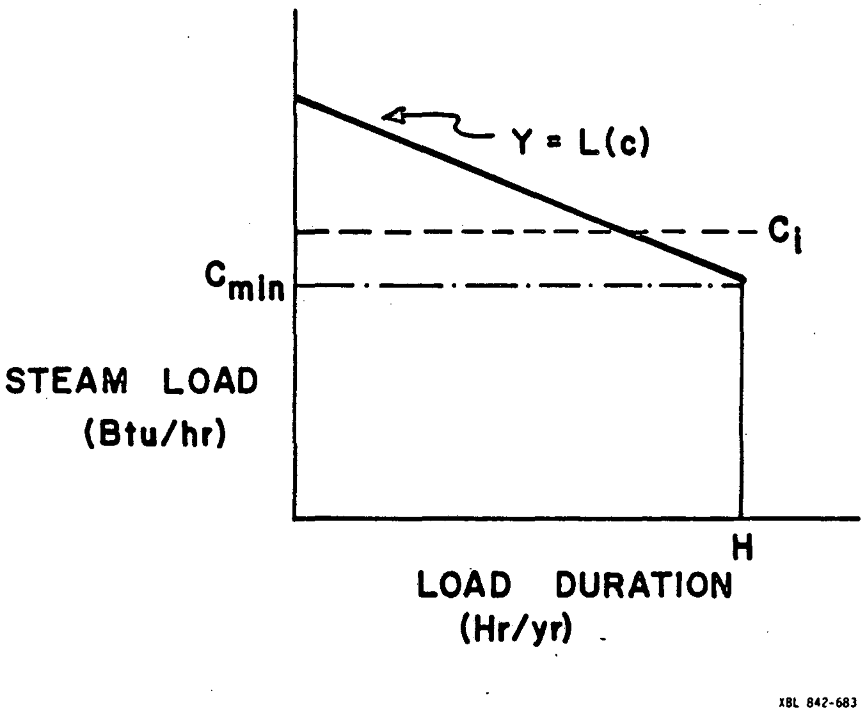

Figure 5-2 Steam load versus load duration

Now choosing C_i affects both terms of Eq. (5-14). Larger C_i will increase E, the electricity output. It will also lower TSS, thereby increasing the second term since Fuel must go up with C_i. This is an operating efficiency trade-off. There remains the scale economy issue for capital costs.

You will recall our discussion of scale economies for central station power plants. Eq. (3-11), for example, indicated one specfication of such cost curves in which total costs increase less than linearly with capacity. This relation is

$$TC(x) = Kx^{1-a}, \qquad (5\text{-}15)$$

where

$TC(x)$ = total cost of capacity of size x,

K = constant,

and

a = constant < 1.

In a situation such as this, the incremental cost of capacity diminishes with increasing capacity, i.e.,

$$\frac{d}{dx} TC(x) = (1-a)\ Kx^{-a} \qquad (5\text{-}16)$$

Therefore the sizing decision comes down to a trade-off between the diminishing costs (Eq. (5-16)) and diminishing benefits (Eq. (5-14)) of larger and larger systems.

The last remaining complexity is that capacity is "lumpy"; it is not available in a continuously varying range of sizes as implied by Eqs. (5-15) and (5-16). Even though scale economies still persist, there is not an infinite, or even very large range of actual sizes. Perhaps the most popular prime-mover for cogeneration systems under development in California is the General Electric LM-2500 gas turbine engine. This unit produces 25 MW of electricity at a full load gross heat rate of 12,500 Btu/kWh. To be economic such units must serve a fairly large steam or heat load. Only then will the net electric heat rate N be competitive with the utility's incremental heat rate HR_u.

In several cogeneration projects currently under development, the economic trade-offs dictate large electricity production to be sold at Avoided Cost. The benefits to project developers come primarily from the heat rate difference between N and HR_u. To finance projects of this kind, lenders will be secure if the QF can guarantee a heat rate floor below which the utility will not go. This does not eliminate price risk, but mitigates it to a substantial degree. Then the only exogenous uncertainty is the fuel price (see Eq. (5-10)). Where natural gas is the fuel in question, there is little room for the price to go down, so the lender faces little practical risk. For QF's the problem reduces to determining whether the heat rate floors offered by utilities yield required returns. If not, the projects are not feasible. The only remaining question is whether the utility forecast of heat rate floors is reasonable. The answer to this question hinges upon a number of assumptions used in the utility production cost models that estimate future Avoided Costs. This area is a subject of current research and modeling.

This concludes our brief survey of small power development. Most of the issues we have explored focus on California conditions where there is the most activity of this kind going on in the country. Other regions exhibit small power development to varying degrees. In general where avoided cost is based primarily on oil and gas fired generation, there is much more activity than regions relying principally upon coal. This is not an invariant rule, however; there are cases of the other kind as well. The key issue for small power development and for our next subject, utility conservation programs, is the cost structure of the utility in the long run. It will be useful to reflect briefly on the generic cost conditions facing electric utilities, and how they determine the value of avoided cost, and the economics of conservation.

5.5 Future Cost Stucture: A Generic Look

It is useful to distinguish utilities which are primarily oil and gas fired on the margin from those which rely principally on coal and nuclear power. This first group includes California (PG&E, SCE, etc.) Texas, Florida and New England as the main regions. The remaining parts of the country depend to varying degrees on coal and nuclear. Some areas such as the mid-Atlantic states and New York are a mixture.

To characterize the two extreme types it is useful to consider the schematic representation of Figure 5-3. In this figure we assume that the Long Run Marginal Cost

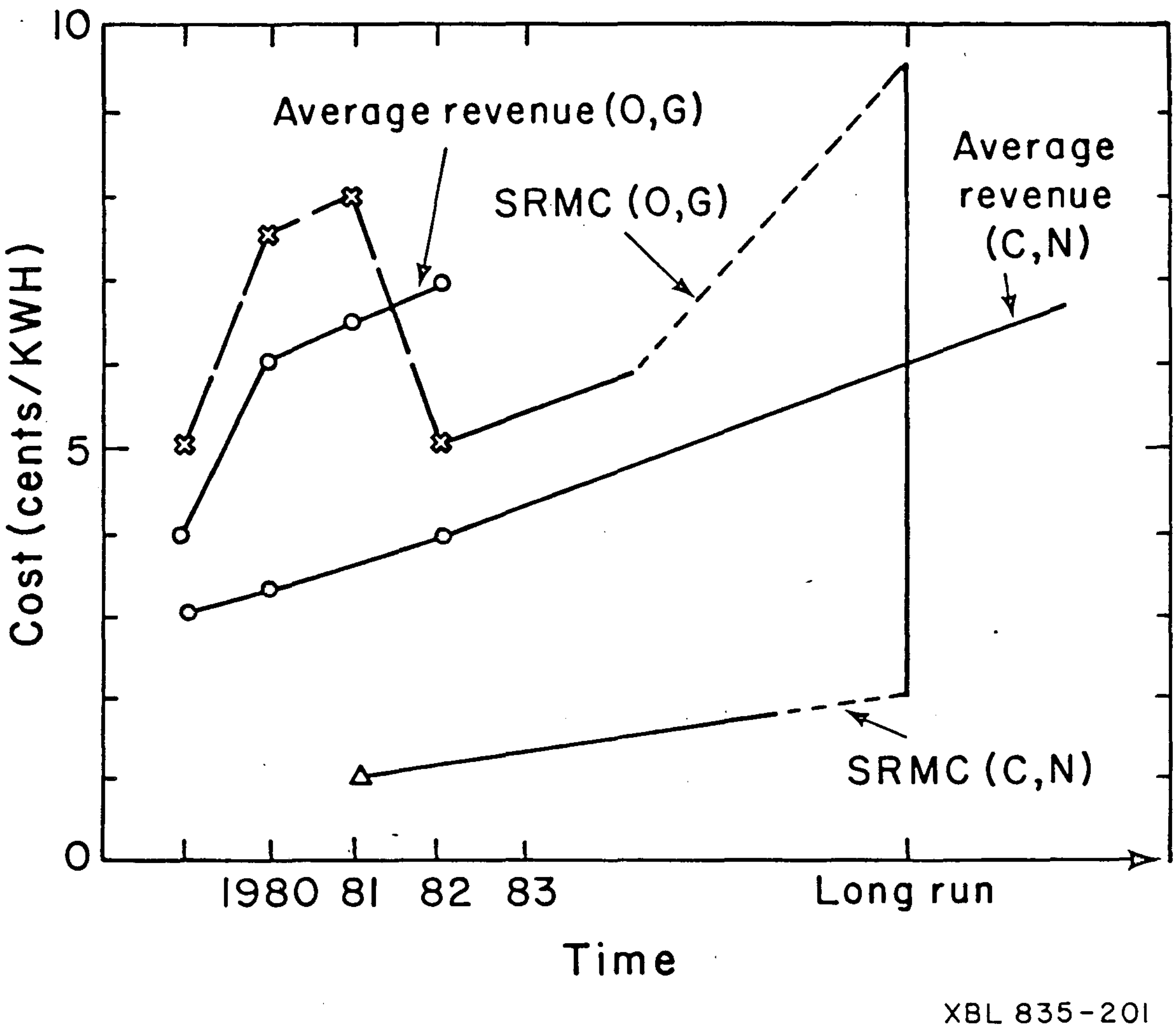

Figure 5-3 Long run marginal cost of electricity generation versus cost

(LRMC) of electricity generation is about 9.5¢/kWh in 1983 dollars. This is roughly the busbar cost of coal-fired generation. We plot both short run marginal energy cost and average revenue for coal and nuclear based utilities (C,N) and oil and gas fired utilities (O,G). Sooner or later we assume that marginal cost (long-run) and average revenue converge. The time path is uncertain, but qualitatively different in the two generic cases. For coal and nuclear, the need for new capacity brings a sharp increase in marginal cost. This is certain. What is uncertain is when demand will require the new plant investment. In the oil and gas case, short run marginal cost (SRMC) is much closer to LRMC. What is uncertain is the relative relation of SRMC and average revenue. Before 1982 we had a period of SRMC > Average Revenue, after 1982 the reverse became true.

In both cases we can speak broadly about marginal cost being greater than average cost, but the differences in detail and timing have important consequences. Consider the case of the coal based utility in an industrially depressed region. If this utility has very substantial excess capacity, as is in fact currently the case in many situations, then only SRMC is relevant. In the long run this utility may in fact face the high marginal cost of a new unit, but the present value of this cost may be neglible if the long run is many years in the future. When the long-run marginal cost becomes relevant, then it is clear that average revenue will still be less than this cost.

The case of oil and gas-fired utilities is different. Here the long run cost interacts more closely with average revenue. It is common for oil and gas-fired utilities to argue that their fuel mix is out of balance and should be optimized by investment in lower fuel cost technology. Such investments will raise average revenues if avoided costs are low; i.e., SRMC < Average Revenues. If avoided costs are high, average revenue will stabilize or even decline over time. The basic uncertainty is exogenous. It is the cost of oil and gas, which is determined outside of the utility's control.

The importance of these cost uncertainties is the complications they introduce into the economic analysis of investment strategy. If we knew for certain the specific trajectory of future costs, then planning could proceed in a reasonably straight-forward fashion. The <u>results</u> of planning might be unconventional. It might be concluded, for example, that increasing costs meant that electricity generation was no longer a natural monopoly. Some form of deregulation might then be a plausible possibility. Another possible conclusion is that increasing electricity production is not economic, and therefore conservation should be subsidized to avoid new construction. We will examine analyses of this kind. The existence of time path and magnitude uncertainties, however, means that generic conclusions may be elusive. Much will depend on particular circumstances. The importance of hedging will also become clear.

With this background in mind we will now turn attention to situations in which utilities have opted for one conservation strategy or another. The logic of these analyses will always have reference one way or another to the particular cost structure facing the company. A representation such as Figure 5-3 is one convenient way to organize the basic relations involved and their variations.

Bibliographical Note

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Chapter 6

UTILITY CONSERVATION PROGRAMS

6.1 Introduction

Conservation programs represent a radical change in direction for electric utilities. The traditional demand side activity of utilities had been marketing new loads by promoting appliances, all-electric homes, or electric industrial processes. With the cost increases of the 1970's, a new interest in conservation emerged in the utility industry. This did not occur uniformly or very quickly. Although the basic economics of increasing cost conditions favored conservation, it was not clear what role the utility should take in promoting it. The key distinction involved the capital intensive nature of efficiency improvements. Even if it is socially efficient to reduce energy consumption, financing the necessary investments is a major undertaking. Consumers will typically under-invest due to imperfect capital markets, regulated energy prices below long run marginal cost and insufficient information.

Various political forces emerged advocating that utilities finance conservation investments. Some utilities initiated such programs, but in many cases outside pressure was fundamental. Intervenors appeared before state regulators arguing that utility resources should be shifted away from central station plants and directed to conservation and small power projects. David Roe of the Environmental Defense Fund represented this perspective in an address at a symposium on this subject in 1980.

> "After all, its the ratepayers' money; its our money. And very frequently the least cost approach is going to turn out to be conservation and other alternatives.
>
> The pressure to perform this kind of work, and the pressure to look seriously at alternatives in time to get utilities to invest in them, rather than in large central station plants, is going to be felt ..... I suggest to you that that pressure, directly applied on the utilities, is what will make the difference, what will get

utility dollars squarely into conservation and alternatives on a massive scale. This will start to turn all the familiar talk about the virtues of conservation into reality."

(California Public Utilities Commission, 1980).

Even among intervenors, however, there was no uniformity of opinion. In California the consumer group TURN (Toward Utility Rate Normalization) which had been instrumental in promoting lifeline rates, opposed utility financing of customer conservation. TURN's position was that allowing utilities to finance conservation was just extending their monopoly, and that this was unwide social policy. TURN's opposition did not prevail, however, and was explicitly rejected by the California Public Utilities Commission in approving the major conservation financing program proposed by Pacific Gas and Electric Company (CPUC, 1981). In fact, the decision in this case was remarkable for the broad range of issues discussed other than the questions of monopoly and competition. Among the most delicate of all these issues were the questions of equity and fairness.

Fairness questions have dominated many discussions of utility conservation programs. The economic framework which was developed to analyze these programs address such cross-subsidization issues directly. In Section 6.2 this framework will be reviewed in some detail. Despite the logic of these concerns, it is reasonable to ask why so much is made about social equity in this context. Leonard Ross, the PUC Commissioner who led the majority implementing lifeline rates, made this case succinctly at the same 1980 symposium mentioned before.

> "Anyone who starts from the assumption that existing utility rates reflect 2500 years of Western concern for equity and justice and the only deviation is how you finance a .... conservation program is living in a world of dreams or bias."

While it is certainly true that traditional rate-making is not a model of equity and justice, conservation programs do tend to increase the ways in which costs could be distributed unfairly. The basic problem is that not all customers will have the opportunity to participate in these programs. Low-income customers in particular may not benefit directly. Even if existing utility rates also have regressive effects, that should not be reason enough to reject concerns that conservation can exacerbate society's inequities. It is also possible that the unprecedented change in role for the utility induces the perception that something must be wrong or unfair. Many consumers and their political representatives find it hard to believe that utilities which formerly promoted consumption, now actually want to reduce their own sales. We will see in Section 6.3 that the nature of regulation does induce some bias into the structure of utility conservation programs.

Finally, we include a discussion of current research issues in Section 6.4. The utility role in conservation is still not well understood. There are many unsettled planning, evaluation and regulatory aspects to these programs.

6.2 Basic Framework of Analysis

Economic analysis of utility conservation programs is unusually complicated. Useful expositions of the relevant factors are given by White and Fiske, et al. It will be convenient to divide our discussion into one part devoted to evaluation criteria, a second part focusing on measurement issues, and a third part on current research. We will begin with evaluation criteria, where the basic issues emerge from the generic fundamentals of increasing marginal cost conditions under embedded cost regulation.

In an unregulated industry equilibrium output would not be expanded if marginal cost could not be recovered with marginal revenue. If costs were increasing, prices would be raised correspondingly. For regulated electric utilities, it is typically the case that marginal costs are not reflected in rates. Incremental output under these conditions is unprofitable, i.e., the cost of capital cannot be earned. The social allocation of resources is equally unsatisfactory because there is "excessive" consumption. One way to illustrate this situation is to examine the benefits of conservation, and how they are distributed when avoidable marginal costs exceed average revenues. White gives a useful discussion of this, starting first from the social perspective.

The benefits to society from conservation are positive when the resource costs of increased user efficiency are less than the cost of new utility supply. Formally we may write

$$\text{Net Social Benefit} = \text{Supply Marginal Cost} - \text{Conservation Cost.} \qquad (6\text{-}1)$$

As long as consumer prices are less than the long-run marginal cost of supply, the consumer benefit of conservation will be less than the net social benefit. In this situation, the utility rate payer gets that part of the avoided cost benefit of conservation which the conserving consumer does not get. This can be expressed as

$$\text{Net Ratepayer Benefit} = \text{Supply Marginal Cost} - \text{Avoided Retail Rates}, \quad (6\text{-}2)$$

and

$$\text{Net Conserving Customer Benefit} = \text{Avoided Retail Rates} - \text{Conservation Cost}. \quad (6\text{-}3)$$

Together Eqs. (6-2) and (6-3) can be substituted into Eq. (6-1) to show how the social value of conservation is distributed, i.e.,

$$\text{Net Social Benefit} = \text{Net Ratepayer Benefit} + \text{Net Consuming Customer Benefit}. \quad (6\text{-}4)$$

To encourage the consumer to invest more in conservation than would be justified by the benefits under average cost pricing Eq. (6-3), the utility could provide incentives that would return some of the social benefits to consumers.

The essence of the utility's intervention into the conservation investment decision of consumers is some financial incentive justified by the previous argument. The logic of this argument suggests that Eq. (6-2), the net ratepayer benefit, defines an upper bound on the size of the incentive the utility should offer. While this is certainly true from a distributional point of view, it is not necessarily true from a resource allocation or societal point of view. It is possible to have a situation in which utilities offer such large incentives that some ratepayers are injured by conservation. This follows because ratepayers provide the revenues which fund these incentives. Therefore where incentives are provided we must re-write Eqs. (6-2) and (6-3) as follows

$$\text{Net Ratepayer Benefit}_{ucp} = \text{Supply Marginal Cost} - \text{Avoided Retail Rates} - \text{Conservation Incentive} \quad (6\text{-}5)$$

$$\text{Net Conserving Customer Benefit}_{ucp} = \text{Avoided Retail Rates} - \text{Conservation Cost} + \text{Conservation Incentive} \quad (6\text{-}6)$$

We use the subscript "ucp" to denote the case of a utility conservation program involving incentives. The net social benefit is still the sum of ratepayer and consumer benefit. Even if Eq. (6-5) < 0, i.e., ratepayers are injured, the social benefit may be positive. The evaluation question centers on whether we require only positive social benefits, i.e., Eq. (6-4) > 0, or positive ratepayer benefits as well, Eq. (6-5) > 0.

Utilities which first initiated conservation incentives tended to require both positive social benefits and ratepayer benefits. This is essentially a strict Pareto optimality rule. The rationale for this is equity related. Eq. (6-5) is often referred to as a non-participant cost-effectiveness test. The ratepayer who does not invest in conservation is discriminated against if Eq. (6-5) < 0. There has been substantial debate over this issue. Some have argued that if the ratepayer loss from conservation is small, then their interest is not unduly damaged. This is like Merrill's concept of strong Pareto optimality where small differences are suppressed.

Another critique of the non-participant test is the demographic/sociological analysis of discrimination in utility conservation programs. Conservation incentives typically involve cost sharing between the utility and the participant consumer. This may be in the form of favorable financing, cash rebates or rate discounts. In all cases the participant consumer must come up with the cash or the credit to finance the major part of the efficient appliance or weatherization installation. Low income consumers and renters commonly lack either the resources or the incentives to make these investments. Why should a tenant improve the landlord's property? How can a low-income consumer benefit from a loan subsidy, if he cannot qualify for credit? These segments of the population will be systematically discriminated against even by a utility conservation program which passed the non-participant test. Such programs can be nothing other than middle class subsidies which will be funded disproportionately by the poor. Therefore they represent regressive taxation in the guise of economic efficiency.

These arguments have often found a sympathetic ear among regulators reviewing utility conservation programs. One response has been the targeting of low-income consumers for special direct action programs. In such cases the utility installs weatherization or other conservation devices, bearing the total cost of such measures. These efforts will almost certainly fail the non-participant test. This may either be limited by the size of the program, or offset by other less costly incentives. We will see examples of such "cross-subsidization" in the utility's conservation portfolio when we examine the case of Southern California Edison.

In practice, the regulator will often settle for a "not too large" net rate-payer loss from utility conservation programs. What the toleration level is for this is difficult to specify. It does highlight, however, the importance of measurement for both costs and benefits. To examine these issues it will be useful to refer to the White and Fiske, et al. papers in detail. White speaks from the perspective of a company in which coal-fired generation represents the marginal cost, and the goal of conservation is primarily to reduce energy consumption (kWh). Fiske focuses on capacity savings through load management. In his case the fuel base is oil and gas. Let us begin with White.

Table 6-1 (from White, 1981) estimates avoided cost components and lost revenue from conservation in the long run. The accounting is done using a mixture of levelized and escalating cost streams. The coal plant capital cost of 27.31 mills/kWh is based on the assumption of a 75% capacity factor (= 6570 hrs/year) and implies annual fixed costs of $179/kW (levelized). The pre-tax cost of capital White used is 17.1%, which implies a total capital cost of the plant equal to $1049 per kW. This may be somewhat low, and the capacity factor may be somewhat high. At a 60% capacity factor, the levelized cost would be 34 mills/kWh. Avoided T and D is assumed to occur with a lag of four years. This is clearly an estimate. The present value of these avoided costs is reduced by the lag. The category called "dry-hole risk" represents the avoided risk of investing in supply projects which may never materialize. Recall Table 3-1 in which the national totals for cancelled power plants are given. The value chosen for this cost is also an estimate, and a very imprecise one at that. To these three level cost items, White adds operating costs at escalating nominal values. It is interesting to note that White's "peaking" category, which corresponds to part of the conservation capacity savings, is very low valued. This suggests that load managemnt will not be particulary interesting to this utility.

Table 6-1

COMPONENTS OF AVOIDED COSTS
IMMEDIATE LONG-RUN MARGINAL COST SAVINGS
(Nominal Mills/kWh)

Year	Coal Power Capital	Coal Plant Operating	Peaking	Wheeling	Transmission & Distribution	Dry Hole Risk	Losses	Total Avoided Costs	Lost Revenue
1981	27.31	21.40	1.97	.75		2.73	5.07	59.23	42.4
1982	27.31	23.22	2.12	.81		2.73	5.26	61.45	48.2
1983	27.31	24.99	2.26	.87		2.73	5.46	63.62	49.6
1984	27.31	26.88	2.42	.92		2.73	5.66	65.92	52.1
1985	27.31	28.81	2.57	.98	5.81	2.73	5.87	74.08	56.8
1986	27.31	30.79	2.74	1.05	5.81	2.73	6.08	76.51	60.5
1987	27.31	32.78	2.90	1.11	5.81	2.73	6.30	78.94	62.7
1988	27.31	34.83	3.07	1.18	5.81	2.73	6.52	81.45	65.9
1989	27.31	36.92	3.24	1.24	5.81	2.73	6.75	84.00	71.9
1990	27.31	39.07	3.42	1.31	5.81	2.73	6.98	86.83	77.8
1991	27.31	41.42	3.61	1.38	5.81	2.73	7.23	89.49	80.2
1992	27.31	43.91	3.82	1.46	5.81	2.73	7.50	92.55	81.5
1993	27.31	46.56	4.03	1.54	5.81	2.73	7.79	95.77	82.4
1994	27.31	49.32	4.25	1.63	5.81	2.73	8.09	99.14	89.4
1995	27.31	52.23	4.49	1.72	5.81	2.73	8.40	102.69	96.9
1996	27.31	55.26	4.73	1.81	5.81	2.73	8.73	106.38	99.1
1997	27.31	58.42	4.98	1.90	5.81	2.73	9.07	110.22	107.6
1998	27.31	61.78	5.24	2.00	5.81	2.73	9.43	114.30	115.8
1999	27.31	65.23	5.51	2.11	5.81	2.73	9.80	118.50	199.5
2000	27.31	68.78	5.79	2.22	5.81	2.73	10.19	122.83	125.5
2001	27.31	72.50	6.08	2.32	5.81	2.73	10.59	127.35	131.8
2002	27.31	76.43	6.39	2.44	5.81	2.73	11.01	132.12	138.4
2003	27.31	80.57	6.71	2.57	5.81	2.73	11.46	137.16	145.3
2004	27.31	84.94	7.04	2.69	5.81	2.73	11.93	142.45	152.6
2005	27.31	89.55	7.40	2.83	5.81	2.73	12.43	148.08	160.2
2006	27.31	94.41	7.77	2.97	5.81	2.73	12.95	153.95	168.3
2007	27.31	100.31	8.15	3.12	5.81	2.73	13.50	160.14	176.7
2008	27.31	104.91	8.56	3.28	5.81	2.73	14.08	166.68	185.6
2009	27.31	110.60	8.99	3.44	5.81	2.73	14.69	173.58	194.9
2010	27.31	116.60	9.43	3.61	5.81	2.73	15.33	180.82	204.6
Present Value								760.5	670.6

To measure the balance between Total Avoided Cost and Lost Revenue, White adds the annual cost components and then present values the thirty year cost and revenue stream. This is legitimate as long as the levelized cost components were levelized using the same discount rate as is used to present value the sum. The formal property White relies upon is

$$\sum_j PV \quad \sum_i b_{ij} + C_j \quad = \quad \sum_j PV \quad c_j + \sum_j PV \quad \sum_i b_{ij} , \qquad (6\text{-}7)$$

where

- j = index for years (rows),
- i = index for cost components (columns),
- c_j = levelized cost elements,
- b_{ij} = nominally increasing cost elements,
- PV = present-value operator.

Eq. (6-7) just says that the present value is the same if we add up the rows first and then present value the columns (left hand side), compared to present valuing the columns first and then adding.

Up to now we have been assuming instantaneous adjustment to the long run cost (with the exception noted above for lagged avoided T&D cost). In terms of Figure 5-3, it is as if the long run cost would be incurred in a lump next year. White also examines the effect of various supply adjustment lags and other arrangements on avoided cost. The point of these calculations is that unless the utility can find a market for its incremental power plant under construction, conservation will cause an under-recovery of the plant's capital costs. Thus avoided cost is lower in these cases than the immediate adjustment scenario of Table 6-1. Thus avoided cost benefits depend critically on timing and measure to a large degree the balance of supply and demand.

Avoided cost is far from the only uncertain quantity in the measurement of quantities in Eqs. (6-1) to (6-6). Perhaps the most crucial quantity in the entire exercise is the load impact of a particular conservation measure or program. Here the Fiske et al. paper shows considerably more sophistication than the White paper. PG&E actually measures the load response to air-conditioner cycling instead of relying upon engineering estimates. Air-conditioner cycling means simply that the utility turns off the appliance for some fraction of each hour to reduce aggregate power demand. The meassurement issue is determining the size of the reduction. This can be particularly important for load management programs where timing and magnitude are critical. The benefits of load management are concentrated into a small number of peak hours of the year. It is useful to examine the PG&E estimation carefully to see what factors are involved.

PG&E develops regression equations to explain the consumption of air-conditioning customers during the cycling period as well as before and after it. The customers are not end-use metered, but rather their total consumption is broken into 2 or 6 hour periods. Each period's consumption (kWh) is regressed against temperature and dummy variables for cycling and time of day. The sample includes both households with and without cycling devices. The coefficient of the dummy variable for cycling customers divided by the number of hours per period gives the kW load impact of the program. Fiske estimates both kW reductions during cycling (-1kW/customer) and increases during the post-cycling period (+0.45kW/customer). Because the value of the former outweighs the cost of the latter, the program is productive.

PG&E's cost-effectiveness analysis follows the general lines indicated in Eqs. (6-1) to (6-6). The main interesting features are empirical or judgmental in nature. When PG&E assesses the avoided costs associated with load management, they appear to allocate avoided T&D to the benefit side. This is certainly clear in our Table 4-2 which is designed to assess the cost-effectiveness of programs such as this one. Fiske's exposition is unclear on this point. If White's assumption is correct, however, that T&D costs are avoided only with a lag, then PG&E is over-estimating benefits. A reduction in benefits would primarily affect the rate-payer or non-participant interest. Indeed, it is the current assessment of PG&E that costs of cycling exceed benefits for ratepayers (Testimony of L. Baldwin, PG&E CPUC Appl. No. 82-12-48, Ex. PG&E -14, Table 1). Nonetheless PG&E recommends such programs on the grounds of their cost-effectiveness to society as a whole.

A last area of ambiguity or uncertainty associated with utility conservation programs involves the size of inceetives. These can be difficult to calculate if they are interest rate subsidies, because you must know the terms of the loan repayment. Originally utilities proposed zero-interest, delayed repayment loans which were only due when the original owner sold the house. These were both very costly and uncertain since you did not know when such sales would occur. White, for example, assumes a 7 1/2% year period on average. It is now more common to rely on 4 or 5 year amortization, such as the PG&E weatherization financing plan (CPUC, 1981).

6.3 Portfolio Considerations

The more difficult problem with incentives is to know how much is enough to induce the desired level of participation. This is not a well-defined problem, but there is a certain amount of evidence suggesting that the range of variation is large. To illustrate this concretely, it is useful to refer to another situation, the conservation program of the Southern California Edison Company (SCE). The differing size of incentives relative to conservation benefits can be analyzed by looking only at the change in utility revenue requirements associated with the various programs. This set of accounting rules is sometimes called the "utility perspective." It is related to the social costs in the following way

$$\text{Net Social Cost} = \text{Net Utility Cost} + \text{Net Participant Cost} \qquad (6\text{-}8)$$

where the change in total revenue requirement is defined as the utility cost. Notice that for a load management program with special rate incentives there is no difference between the utility cost and the social cost, since the participant pays nothing. Where the participant shares the cost, these concepts will differ. Table 6-2 shows the different relationships between utility cost and benefit of the various conservation programs proposed by SCE in 1981 and 1982.

The programs listed in this table come from two separate applications by SCE to the CPUC. Although they were not adopted in detail as presented here, the data are representative. Inspection of the program elements aggregated to this level shows an order of magnitude difference in the benefit-cost ratios. The most productive programs are characterized by the relatively small size of the utility incentive compared to customer investment in conservation. The Commercial and Industrial Audit Program typically underwrites about 10% of the customer costs. When these consumer costs are added in, the social benefit cost ratio is only about 2.5 to 1 instead of 25 to 1 from the utility perspective. Similarly the efficient refrigerator incentive program underwrites about 15% of consumer cost, so that the total social benefit-cost ratio in this case is also about 2.5 to 1. By comparison all the load management programs have about a 2.2 to 1 benefit-cost ratio. In this case since all costs are paid by the utility, there is no difference between this perspective and the social perspective.

Table 6-2

1983 TOTAL SCE PROPOSED PROGRAM - UTILITY PERSPECTIVE
(Millions of 1983 Dollars)

	Cost	Benefit	Benefit/Cost
1. Commercial and Industrial			
a) Conservation (Audit + Incentives)	28	696	
b) Load Management	18	32	
Total	46	728	
2. Residential			
a) Conservation			
1) ZIP/CIP	18	54	
2) Rate Case	17	58 (?)	
b) Load Management	28	68	
Total	63	180	
TOTAL BUDGET COMMITMENT			
Complete Program	109	908	8.3
3. Selected Elements			
a) Total Load Management	46	100	2.2
b) ZIP/CIP Refrigerators	1.5	23	15.3
c) C & I Audits (= 1a)	28	696	24.9
4. Total Program Sensitivity			
a) Without C & I Audits	81	212	2.7
b) Without C & I Audits and Residential Information Programs Fail	81	154	1.9

The principal problem associated with Table 6-2 is to understand what contributes to the structure of the program as a whole. One way to pose this problem is to ask why SCE allocates such a large fraction of the total budget to load management (42%) when the benefits produced are such a small fraction (11%)? To attempt an answer to the question, we will try to account for the uncertainties associated with the Table 6-2 estimates. It will also be important to consider the shareholder interest in these programs explicitly as well. These two factors have been more or less neglected in the cost-effectiveness accounting framework. Let us begin with the uncertainty issue.

To understand the sources of variability in the benefits estimated for SCE's or any utility conservation program it is convenient to decompose the benefit term as follows

$$\text{Conservation Benefit} = \text{Annual Load Impact} \times \text{Lifecycle} \times \text{Value per Unit.} \qquad (6\text{-}9)$$

Each term in Eq. (6-9) can be uncertain. Unless the load impact is measured, estimates will have some unavoidable error associated with them. Certain programs, such as information dissemination, are almost impossible to measure. Even if an annual load impact can be determined to within a reasonable tolerance, the persistence or duration of the effect may be uncertain. Eq. (6-9) uses the term "lifecycle" to indicate the number of years the load impact is expected to last. Residential appliances have reasonably well known lifetimes, so the uncertainty with respect to lifecycle may be minimal for applicance efficiency programs. Conservation practices which have more of a behavior element can be of very uncertain duration. Even conservation hardware may be prematurely removed as occupancy or use patterns change. Finally, there is a substantial difference between uncertainties in the value of energy and capacity, particularly in the case of an oil and gas fuel based utility like SCE. The recent history of oil prices on the world market suggests a standard deviation of real price that is about 30% of the mean. Gas turbine costs, the typical proxy for capacity value shows only about a 10% standard deviation. This means that capacity savings are less uncertain per unit of value, than oil and gas based fuel savings. These three uncertainties are evaluated qualitatively in Table 6-3 for three representative programs.

The Table 6-3 summary suggests that load management benefits are on the whole less variable or uncertain than other programs. This greater certainty allows for somewhat lower benefit-cost ratios. Perhaps an equally important facter, however, is recip-

Table 6-3

UNCERTAINTY MATRIX

	Annual Load Impact	Lifecycle	Value per Unit
Information Dissemination	large	large	kWh; $\sigma = 30\%$
Appliance Efficiency	small		kWh; $\sigma = 30\%$
Load Management		moderate	kW; $\sigma = 10\%$

ient of the benefits. Capacity savings associated with load management are essential in the case of SCE to produce net positive ratepayer benefits. One illustration of this is Figure 6-1 which shows the difference between avoided energy costs and lost revenues estimated by SCE (ZIP/CIP) and by the CPUC staff (Czahar). When a capacity value of roughly 20 mills/kWh is added to these estimates, the ratepayer benefit identity switches from negative (as shown in Figure 6-1) to positive.

Another illustration of this is found in Table 6-4. Here SCE's ZIP/CIP program is summarized from three different perspectives. In general, non-participants get a small share of the benefits from each element or lose. When fixed overhead costs of administration are added, the non-participants would be losers except for the load management benefits. Only here do the participants receive relatively little, and the non-participants capture the major portion of the benefit.

One less thoroughly discussed reason why the rate-payer or non-participant perspective gets so much attention in the conservation progam evaluation literature is that the shareholder's interest is substantially identical with it. This can be illustrated in the following manner. Suppose there were no conservation. If demand increased one kWh, the fuel cost would be automatically recovered through the utility's fuel adjustment clause. If peak load increased one kW and the utility had to recover the capital investment cost through rate increases, there would be a risk that the full cost of capital would not be earned. Thus the capital minimization strategy of utility investment favors load management expenditures. Recall Eq. (3-23) says that where the utility's market to book value ratio is less than one, shareholders want to limit investment. A load management program which can be "expensed" instead of "capitalizing" helps achieve this. (For a formal analysis of the capitalizing vs. expensing decision, see Linhart, et al. (1974) paper, which concludes that where investor returns are less than the cost of capital, expensing will be favored by shareholders).

As a final note on the shareholders ambiguous attitude toward conservation we must observe the use of cross-subsidies in the design of the ZIP/CIP program. Figure 6-2 shows how the various program elements fall out with respect to incentive size (x-axis) and ratepayer benefit (y-axis). The mandatory load management program of Table 6-4 is labelled AC Cycling here. Since it is mandatory the incentive is zero. Now observe the Heat Pump Furnace. This item has over 40% of consumer cost being subsidized and involves a net ratepayers cost of about $1000 for each unit installed. Why then promote

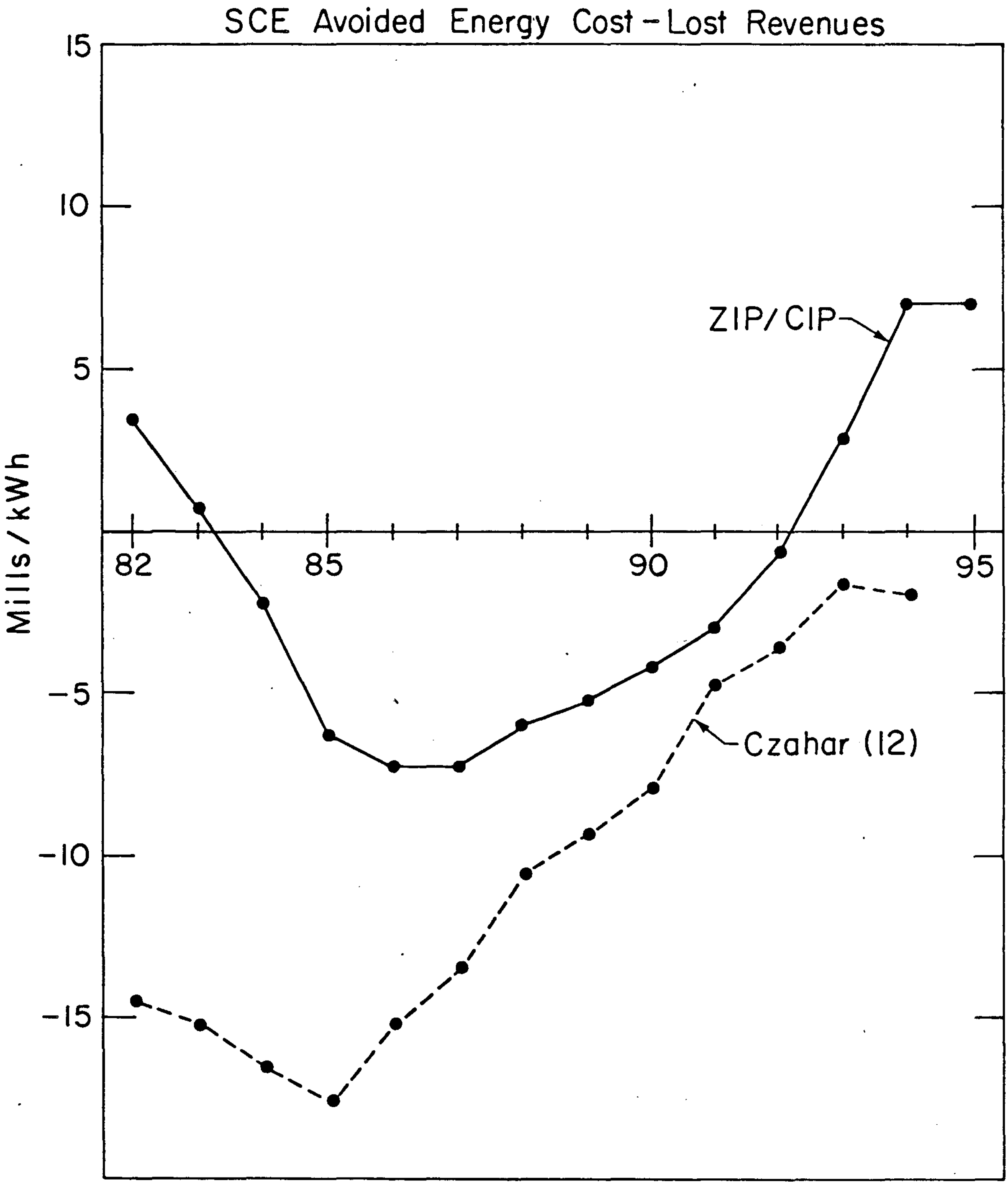

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Figure 6-1 SCE avoided energy cost - lost revenues

Table 6-4

SCE ZIP/CIP: DISTRIBUTION OF BENEFITS
PRESENT VALUE OF LIFE CYCLE SAVINGS
(Thousands of 1983 Dollars)

	Utility	Participant	Non-Participant
Measure Type			
Building Shell			
Improvements	1,874	1,502	- 4
Appliances			
Heat Pumps	4,048	3,048	- 325
Cooling	26,181	19,562	515
Refrigerators	23,125	15,133	1,305
Load Management	2,769	2	2,769
TOTALS	57,997	39,243	4,257
Fixed Costs	- 4,201		-4,201
Net Benefit	53,796	39,243	56

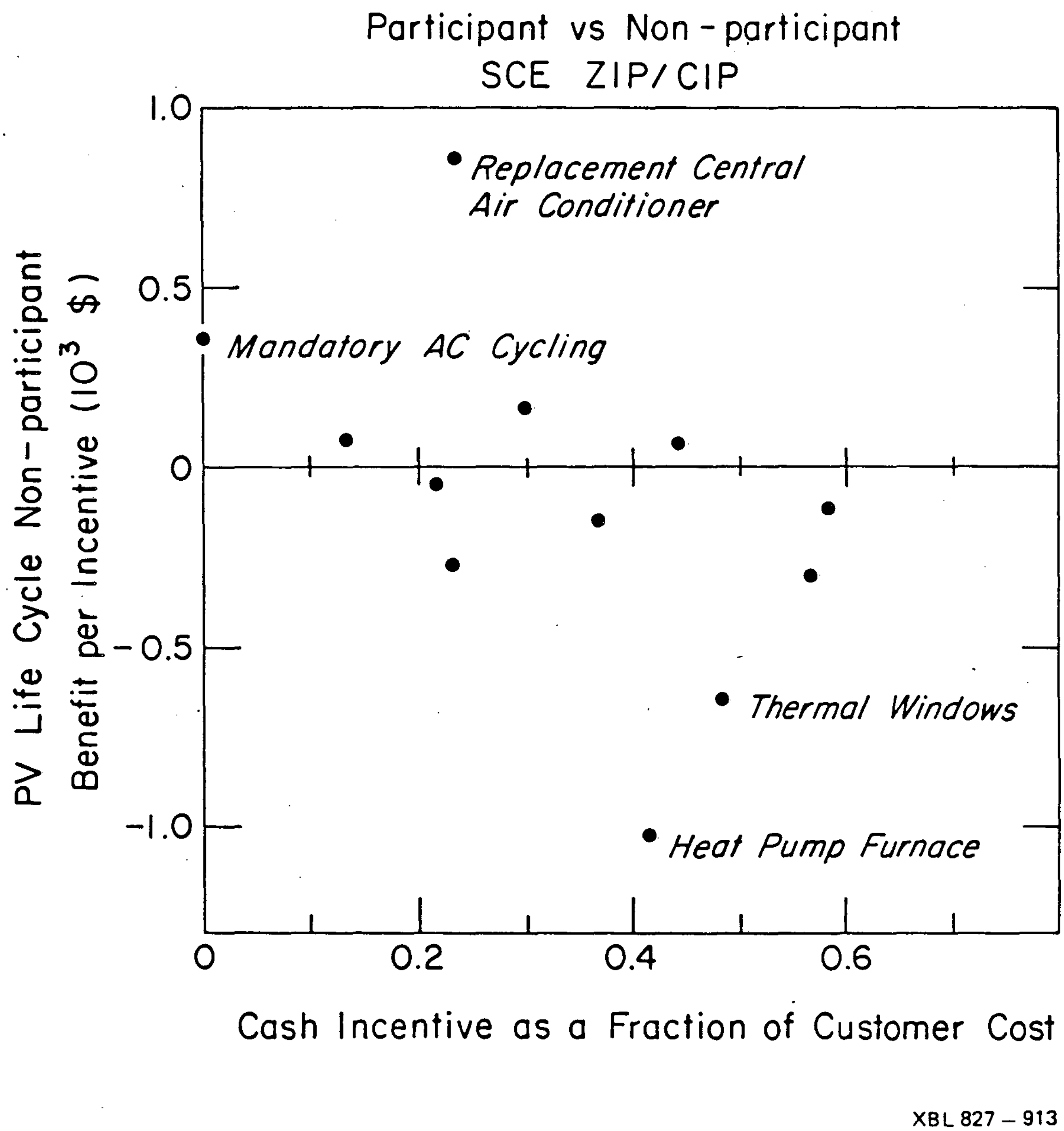

Figure 6-2 **Participant versus non-participant, SCE ZIP/CIP**

this? Is it really conservation? While it is impossible to give conclusive answers here, it is plausible to suggest that SCE is using the ZIP/CIP program to hedge against "too much" conservation by promoting load building activity as well. In the long run, electric heat pumps represent one of the few available technologies that might significantly increase consumption of electricity by residential customers. Should cost conditions warrant it, utilities might find it profitable to market the heat pump aggressively. In some regions of the country this is already done (these are principally coal fired utilities with much excess capacity and relatively low short-run marginal costs). SCE can be thought of as building up a small customer base for heat pumps, giving the utility the option of aggressive marketing in the future. Here the interest of shareholders and ratepayers diverge in the short run at least. To achieve this market foothold for the heat pump, SCE imposes substantial costs on non-participant ratepayers. These are then hidden in the overall program; subsidized by other more productive elements.

Thus the role of utility conservation programs remains ambiguous. The economic rationale for this activity rests largely on assumptions about future cost structure that are uncertain. As a "production" strategy for utilities conservation is at best novel and perhaps only a temporary accommodation to unfavorable conditions. It would be a happy co-incidence if shareholder interests and customer interests could both be served by conservation as they were once served jointly by growth. This unity of interest is not necessarily likely in the long run. Moreover, the cost conditions necessary for this result might also induce structural changes more generally in the organization of the electric utilities. After all, if costs are increasing in the long run, perhaps the entire basis of the natural monopoly has been eroded in a permanent way.

The questions raised by utility conservation programs strike at the very core of the principles of public utility regulation. Given the changes in cost structure over the past decade, it becomes necessary to ask whether the traditions of regulation and the more recent adaptations are compatible. To answer these questions we must examine the theory of natural monopoly more carefully. These theoretical issues are raised in Chapter 7.

6.4 Current Areas of Research

Because conservation is both a relatively new subject and a difficult one for planners, there is much which remains to be learned. A useful way to understand the current limits of analysis is to survey the research agenda. This section will illustrate the problems associated with and disagreements about the cost-benefit framework outlined above.

The basic problem for conservation planners is that it is hard to know how much demand reduction is possible and economic. The total potential is the sum of many small actions whose cumulative effect is large. The aggregation of individual measures is difficult because there may be technical interactions among measures and complicated economics. One approach to the aggregation problem is the "conservation supply curve" (Meier, 1983). This formulation conveots conservation capital costs into a cost per unit of energy saved by assuming (1) performance per unit, (2) lifetime, and (3) a discount rate to determine a capital recovery factor. Having achieved the transformation to cost per unit, then some estimate of total potential market is needed. With such estimates then a total potential "supply of conservation" can be arranged on an increasing cost basis as normal supply curves are drawn.

There are, of course, many problems with this approach. The transformation of conservation capital costs to a unit basis requires estimating uncertain quantities. The choice of lifetime and discount rate in particular can express either a long-run social perspective or a more short-run consumer perspective. The shape of a given curve will change depending on the choice of perspective. There are also ambiguities surrounding the estimated performance per unit of a conservation measure. Some of these problems are measurement difficulties involving the variability of consumption patterns. Others are evaluation problems. Even if consumption variability can be controlled for, it is not clear that measured savings in a given situation can be fully attributed to a particular conservation program.

The evaluation issue has been discussed most extensively by Hirst and associates. For many conservation programs the kind of rigorous load impact testing described by Fiske has not been done. Especially in the case of kWh impacts, it is important to account for price induced demand reductions. One must also normalize for climate variations, self-selection of program participants and other factors. But of all these effects, price is the most important and difficult to understand. The problem is deep here because of the conceptual confusion between the "conservation as supply" framework and the micro-economic perspective that conservation is a demand response induced by price. Hirst tries to solve this be using a gross versus net theory. Put simply let us imagine two customer groups D_a and D_b and two time periods. The difference between the customer groups is that D_a participates in a conservation program. The gross program impact, GI, is then given by

$$GI = D_{a1} - D_{a2} \tag{6-10}$$

But if price increases then some part of GI would have happened anyway. This can be found by looking at the suitably normalized consumption changes of D_b. Let us call this MR (for market response); then MR is given by

$$MR = Db_1 - Db_2 \tag{6-11}$$

and then

$$\text{Net Impact } NI = GI - MR \tag{6-12}$$

The basic problem is that MR is very difficult to measure and its conceptual relation to GI is not clear. MR includes both a substitution effect which is a long run stock response and therefore comparable to GI, but also an income effect. The income effect is much harder to relate to GI. To separate the mix of long and short run effects in both GI and MR is also difficult.. Therefore, calculating NI is quite uncertain. All that can be said in general is that because we expect $MR > 0$, then we also expect $NI < GI$. Ford (1983) among others points out that it is really only effective to subsize NI. Therefore the subsidies to GI include a redundant element. It would be better then to target subsidies only to the less cost-effective region of the conservation supply curve, conditional on inducing customers to purchase the more cost effective measures themselves. Southern California Edison's C&I Audit Program has such a feature in it, but this is atypical.

Another way to express why the Hirst paradigm is difficult to implement is that the price elasticity of demand implied or embodied in the estimate of MR is itself quite complex. Again the issue is the substitution versus the income aspects. Standard micro-economic theory suggests that elasticities are a function of the consumer's budget share for the commodity. Empirical estimates of this relation in the long run are shown in Figure 6-3. The general trend is clear but the estimates differ widely. This figure suggests that distributional issues are fundamental to conservation program evaluation. The budget share of electricity varies with income level, being higher for low income customers. The demand for conservation, as well as the demand for energy depend on both the current and future distribution of income. To date most methods of estimating these demands do not incorporate distributional considerations.

The one principal exception to this trend is the REEPS model (or Residential End-use Energy Planning System) based on the work of McFadden and associates. This model simulates the household demand for appliances based on surveys of existing holdings and a behavioral model of the purchase decision. The model is primarily designed to forecast electricity demand for residential customers. It is also useful to assess the impact of certain conservation programs. Because it is structured to represent different income groups explicitly, REEPS is a uniquely valuable tool for assessing distributional issues. Its main drawback is its very substantial data requirement based on a fine level of disaggregation. Another approach to the distributional aspect of demand and conservation behavior is analysis of sales frequency distribution data such as that discussed in Chapter 4. This approach is new but promising.

Finally there are a number of regulatory issues which are still far from being settled. These include the difference between conservation in a growing versus a no-growth utility. An explicit treatment of this issue is embodied in the Florida Public Service Commision cost-effectiveness reporting format (1982). The question of rate treatment for conservation costs is also a matter of some contention. Utilities have shown a preference for expensing these costs instead of capitalizing them. The general reasons for this preference are consistent with Linhart's classic analysis of this choice. The basic reason is just "capital minimization" as discussed in Sec. 3.4. Counter-examples such as the guaranteed return for PG&E's ZIP program are not explained by this theory however.

It is likely that conservation will remain problematic. Although clearly a demand-side behavior, it substitutes for supply side activities. Hence, there is a tendency for planners to put the "conservation resource" into the framework of supply analysis. This transformation is not unambiguous or straight forward. Furthermore, as we shall see in

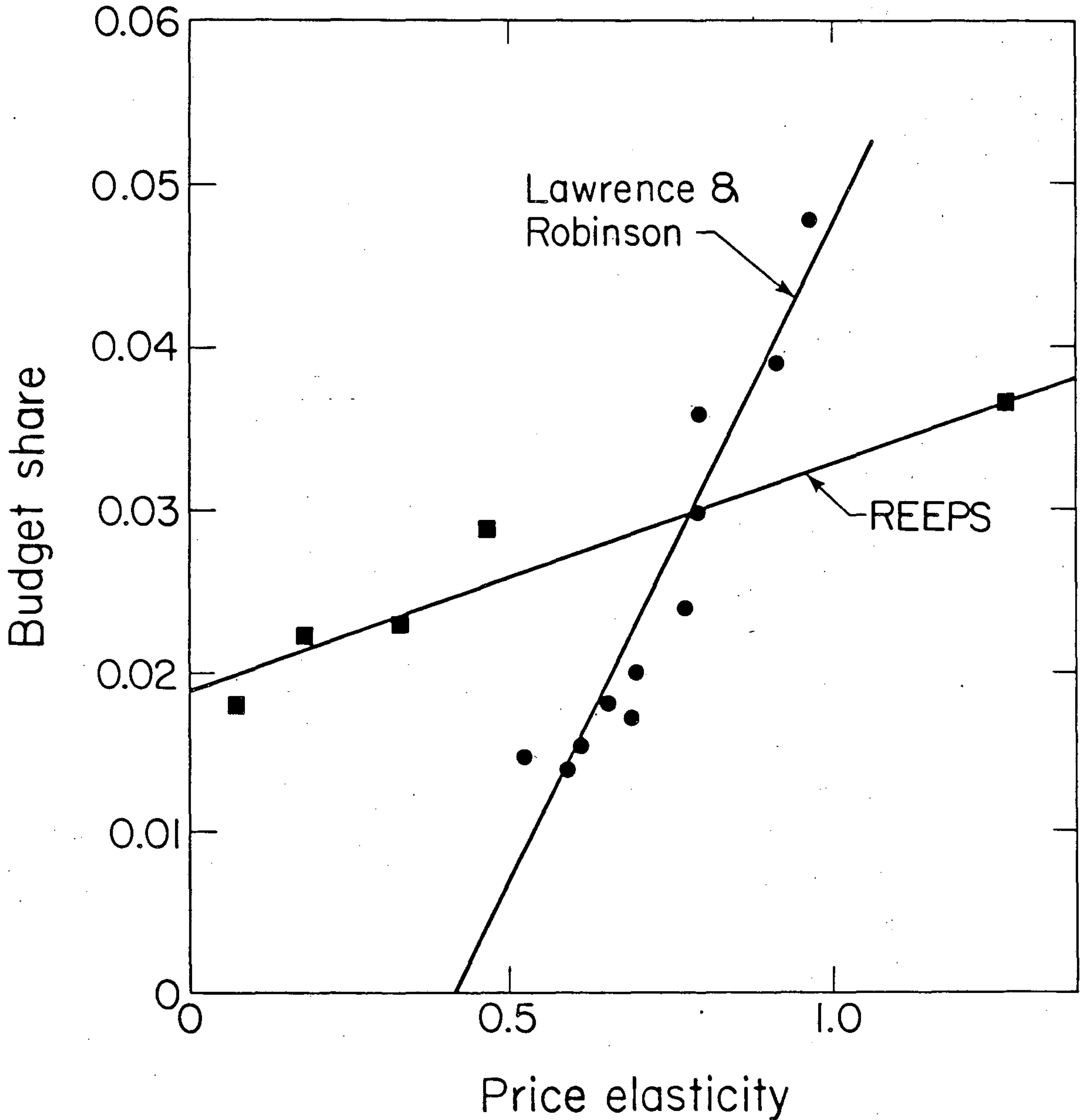

Figure 6-3 **Elasticity as a function of consumer budget share of commodity**

Chapter 7 the utility has an ambiguous attitude toward conservation. At some point it will not be in the shareholder's interest to diminish the market by reducing demand. To understand this conflict we need to understand the role of conservation in the overall structural problems of the electric utility industry. This means re-examining the theory of natural monopoly.

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Chapter 7

THEORETICAL PERSPECTIVE

7.1 Introduction

In this chapter we develop a theoretical perspective on the developments we have surveyed to ask where the electric utility industry is going in the future. We first review the theory of natural monopoly. In its modern form this theory indicates that there are cost configurations which are still natural monopolies even though costs generally rise with output. At some point, however, natural monopoly breaks down. The certain test for this breakdown is the entry of other firms into the market. Entry means not just the appearance of other firms, but their long run viability. Thus in electricity the mere existence of QF's does not mean that the market is not a natural monopoly. Only the long run survival of QF's means that.

To put the problems we are interested in in a new light, it is useful to translate then into the language of uncertainty and instability. The political and economic upheavals of the 1970's clearly de-stabilized the electric utility industry. Conditions which used to be predictable like demand and cost became uncontrollable, uncertain and volatile. Under these conditions inflexible supply projects such as nuclear and coal power plants exacerbated the difficulties. We will develop a simple example due to Sharkey illustrating these conditions.

The advantage of the stability language in addition to its realism is the natural way in which regulation is characterized. The regulator's service to society is providing stabilization to unstable markets. This is particularly clear in the area of agriculture, where government authorities buffer producers and consumers from price and production fluctuations. We will argue that it is also a useful way to characterize regulation of electricity. Students of administrative processes have observed that stabilization is the effect of regulation operating primarily through procedural delays. Actors in the drama consciously use this feature to achieve policy goals. But stabilization services can be ambiguous in themselves. The "regulatory lag" of delayed price adjustment will favor producers when cost is declining, it favors consumers when cost is increasing.

Most students of regulation focus on the issue of what determines regulatory policy. Critics of regulation often argue that decisions always favor producers. The regulator is "captured" by the industry. We will argue a somewhat different perspective. In essence, the theory is simply that regulators serve that interest which benefits most from stabilization actions. To develop this point of view we adapt some simple characterizations of the value of stability to the electric utility context. We use these tools to distinguish the producer from the consumer interest. This framework accounts for the "pro-consumer" bias of utility regulation during the 1970's and can be used to predict a shift in policy back toward producer interests.

The stabilization framework also allows formulation of strategic alternatives for the electric utility industry. If the cost structure is fundamentally unstable even though generally increasing, what should the traditional firm do? To answer this question, we estimate where the producer value of stabilization is greatest for certain generic production strategies. It turns out that "unregulated" production benefits most from stabilization compared to central station regulated production or utility conservation programs. The latter turns out to be ambiguous. If conservation can bring the utility cost structure back to the sustainable monopoly region, then its competitive strategic value is great because this is equivalent to driving small power producers out of the market. The risk of "too much" conservation is that the utility ends up with excess capacity. It will then have won a battle, but not gained much in the process.

The value of stabilization to "unregulated" production, together with the theory of unsustainable natural monopoly suggests that the structure and number of firms in the electric utility industry will change. It may, however, be misleading to label these changes deregulation. Although more competition will be introduced in the market for power generation, the traditional firm is unlikely to disappear. Transmission and distribution remain natural monopolies. There are still economies of vertical integration with generation. Instead of old firms disappearing we will more probably see new entrants and new roles for the traditional firm.

We begin the discussion with a review of the theory of natural monopoly in Section 7.2. Sharkey's example of an unstable market is given in Section 7.3. The stabilization theory of regulation is applied in Section 7.4. Future directions are sketched in Section 7.5.

7.2 Theory of Natural Monopoly

The standard definition of a monopoly equilibrium is that the monopolist maximizes profit by choosing a price that yields the optimal output. The classical illustration of this process in a single product market is Figure 7-1. The monopoly output is maximizing revenues minus costs. The revenue function can be expressed as the product of the inverse demand function p(q) (the line D) and the quantity q. This may be written

$$\text{Maximize } \; p(q) \times q - C(q), \tag{7-1}$$

where

C(q) is the total cost function.

Since p and q are related through the market demand function, we can just as easily view the process as finding an optimal output q_m. Solving the first order condition leads to the result that when $q = q_m$

$$p(q) + q \frac{dp}{dq} = \frac{dc}{dq} . \tag{7-2}$$

The left hand side of Eq. (7-2) is just the marginal revenue MR, and the right hand side is the marginal cost, MC. The shaded area represents the "welfare loss" of monopoly, because every unit of output between q_m and q_c is valued by consumers more than the cost of production. Regulation typically forces a lower price corresponding to q_c, thereby expanding output, lowering profit and eliminating the welfare loss.

Figure 7-1 is too simple a representation to account for many of the complexities of monopolies such as electric power. Among the difficulties are (1) multiple demand curves (corresponding to customer classes with different price elasticities), (2) multiple outputs (capacity and energy are not the same commodities), (3) uncertainties and non-linear prices, and (4) the public goods aspect of utility service. All of these factors influence both the definition of a natural monopoly and the empirical issue of whether a particular industry has these properties.

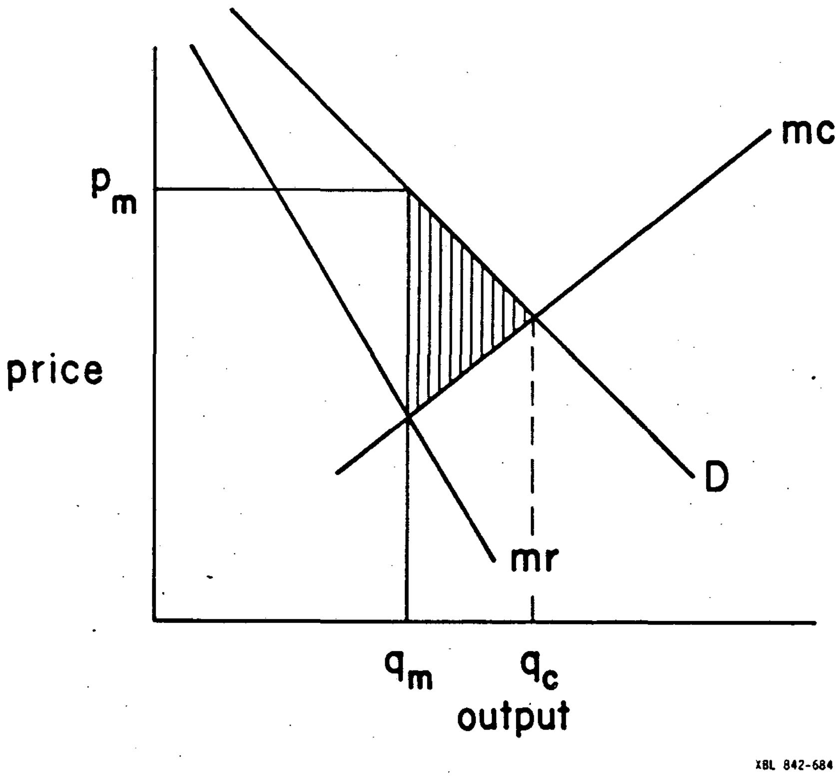

Figure 7-1 Price versus output

Many of these issues arise from the existence of scale economies or increasing returns phenomena of other kinds. An electric power system can typically serve many customers with diverse demands more efficiently than atomized or totally decentralized production. In doing this, however, many constraints exist which prevent simple pricing or output rules from being formulated. Some commodities are produced which cannot be easily priced. Reliability is an example of this. All consumers benefit from reliability but to different degrees. Since reliability is like a public good and cannot be "decomposed," everyone consumes the same "amount" of it, at least at the bulk power level. Consumers cannot reveal their true preference for this commodity since it is not easy to experiment with the acceptability of various quantities of reliability. Sharkey's discussion of the Lindahl equilibrium for public goods raises the issue of a consumer's willingness to reveal his true preference if his price for this good will be proportional to that preference (assuming he knows it). This is the familiar "free-rider" problem.

Even within the realm of more conventional commodities, scale economies are ubiquitous. There are many ways to define this concept, but the modern notion of sub-additivity of the cost function is the most general. This concept is defined formally by the property

$$C(y) < c(x) + C(y-x) \text{ for } o < x < y \tag{7-3}$$

where

$c(q)$ = the total cost function for output q.

Eq. (7-3) says that a cost function is sub-additive if the sum of costs for two output levels produced separately is always greater than the cost of producing the sum of the two output levels. This notion includes the case of declining average cost but is more inclusive. This can be illustrated by considering a cost function with global scale economies. Let us define global scale economies by the following property

$$C(\lambda q) < \lambda C(q) \text{ for } \lambda > 1, q \geqslant 0 . \tag{7-4}$$

To show that Eq. (7-4) defines average cost as a decreasing function of output, just divide both sides by λq. Then we get

$$\frac{C(\lambda q)}{\lambda q} < \frac{C(q)}{q}, \tag{7-5}$$

which says that unit costs go down on the average with increasing output. Sharkey uses the property defined in Eq. (7-5) to show that global scale economies imply cost sub-additivity. For $q>x$ then

$$\frac{C(x)}{x} > \frac{C(q)}{q} \quad \text{and} \quad \frac{C\ (q-x)}{q-x} > \frac{C(q)}{q}$$

Therefore we can add $C(x)$ and $C(q-x)$ as follows

$$C(x) + C(q-x) > C(q) \left[\frac{x}{q} + \frac{q-x}{q} \right] = C(q) \ ,$$

which is the definition of sub-additivity.

Cost sub-additivity provides a natural definition for the notion of cross-subsidy which is so important in public utility regulation. The idea is simply to compare the prices charged to a particular customer or group of customers with the "stand alone cost." If this group is asked to pay as much or more than the stand alone cost of providing it service, then there is no subsidy. As long as the cost function is sub-additive, then subsidy-free prices can be found. This can be seen simply by re-arranging the terms of Eq. (7-3). Let $q_3 = q_1 + q_2$ then sub-additivity implies

$$C(q_1 + q_2) < C(q_1) + C(q_2),$$

or

$$C(q_1 + q_2) - C(q_2) < C(q_1). \tag{7-6}$$

Eq. (7-6) says that the cost of serving any group of customers alone exceeds the incremental cost of service when the group is part of a larger whole.

The importance of the sub-additivity notion is that it extends to situations involving increasing average cost. An example of such a situation is illustrated in Figure 7-2. Here the cost function is sub-additive up to the quantity q^*. Beyond that there are no increasing returns, i.e., $2\ C\ (q/2) < C(q)$. The quantity q_o represents the point at which the cost function $C(q)$ becomes increasing in average cost. The slope of the line through the origin is falling for levels below q_o, and rises after that level. This slope is just average cost, $C(q)/q$.

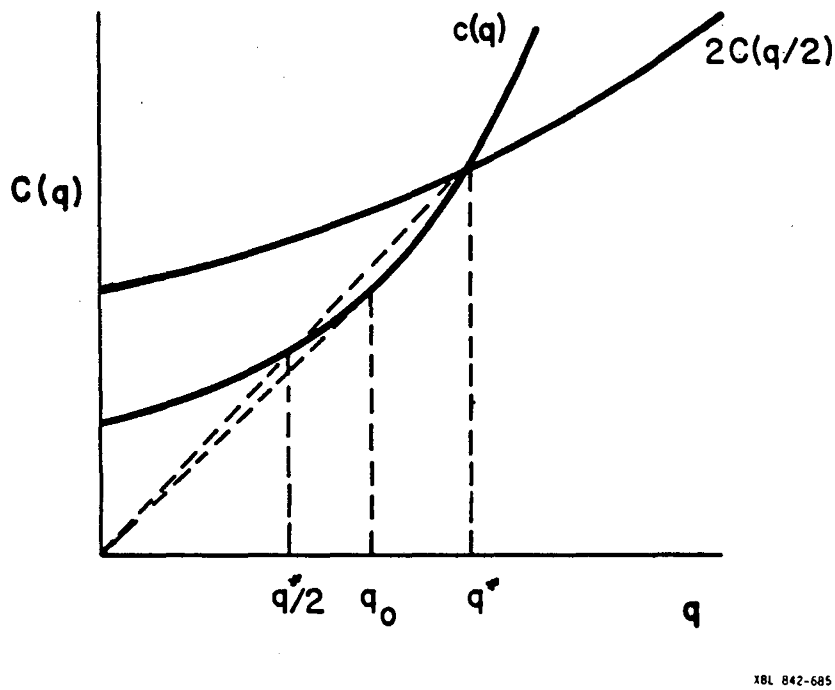

Figure 7-2 c(q) versus q

The importance of the region between q_o and q^* is that it represents a cost structure in which although costs are increasing, natural monopoly conditions still obtain. This possibility was not treated explicitly in the literature until recently. It has considerable relevance for the electric power industry today. We have seen that costs are definitely going up on the average and in the long run. The critical question is whether this process has proceeded to the point where subsidy-free prices can no longer be constructed, i.e., the cost function is not still sub-additive.

In practice, such questions are difficult for a number of reasons. One rule of thumb favored by economists for constructing discriminatory prices which are still efficient is called the Ramsey pricing rule. The basic idea is that departures from marginal cost pricing are still efficient if all outputs are in the same proportion as they would have been if pricing were done at marginal cost. This notion formalizes the existence of two or more outputs (which also may be construed as customer classes) called q_1 and q_2. We can write the demand functions as follows

$$q_1 = D(p_1),$$

$$q_1 = D(p_2). \tag{7-7}$$

The Ramsey rule for departing from marginal costs c_1 and c_2 is that the following ratio holds

$$\frac{D_1\ (P_1)}{D_1\ (C_1)} = \frac{D_2\ (P_2)}{D_2\ (C_2)} \tag{7-8}$$

Equation (7-8) indicates that P_1 may depart more from C_1 compared to P_2 and C_2 if the demand for the first good is less elastic. A formal rule for achieving this result in the case of independent demands is given by

$$\frac{P_i - C_i}{P_i} = \frac{-k}{n_i}, \quad i = 1,\ 2 \tag{7-9}$$

where

n_i = elasticity of demand of good i,

and

k = constant.

Figure 7-3 illustrates the logic of the Ramsey rule. To curtail demand from q_2 to q_1 requires a greater increase of p_1 over p_2 for inelastic markets compared to elastic ones. For increasing cost industries such as electric power, Ramsey pricing implies that large users (who are typically more elastic) will get smaller rate increases than small residential users, who are less elastic.

Ramsey pricing is related to the notion of cost sub-additivity because demand elasticity is related to stand alone cost. In the limit, a large user is elastic because he can always produce his own power, that is, his potential for substitution is complete. Therefore to keep such customers in the system, the utility must discriminate in their favor. At some point, this can no longer be done. Either the price is not sufficiently favorable to retain the elastic customer, or it is no longer worth it to the inelastic consumer to subsidize the elastic class. At this point natural monopoly breaks down.

It is difficult to apply much of this theory to real industry situations. The theory is couched at such a general level that it is difficult to translate it into the terms of analysis used at the empirical level. One development of this approach in the direction of completeness is the extension of the definition of cost sub-additivity from single product markets to multi-product ones. Here the issue often turns on whether there are economies of joint production or cost complementarities between the outputs in a multi-product firm. It is possible, of course, that dis-economies could exist as well. An academic example of a joint production dis-economy is the combined eduation of lawyers and philosphers. The latter must be taught to pursue only the truth. This proclivity is not efficient for producing the former.

The main result of the theory generalized to multi-product cases is that natural monopolies (i.e., cost functions which are sub-additive) may not be sustainable in the long run. An unsustainable monopoly (or industry structure) is one in which entry is possible. The central question posed by this analysis is whether electric power is still characterizable as a natural monopoly, and if so, is it sustainable? In all likelihood the answer will turn out to be that if the cost function is still sub-additive, entry is indeed possible. Therefore the equilibrium industry structure either will include many firms, or there is no equilibrium at all.

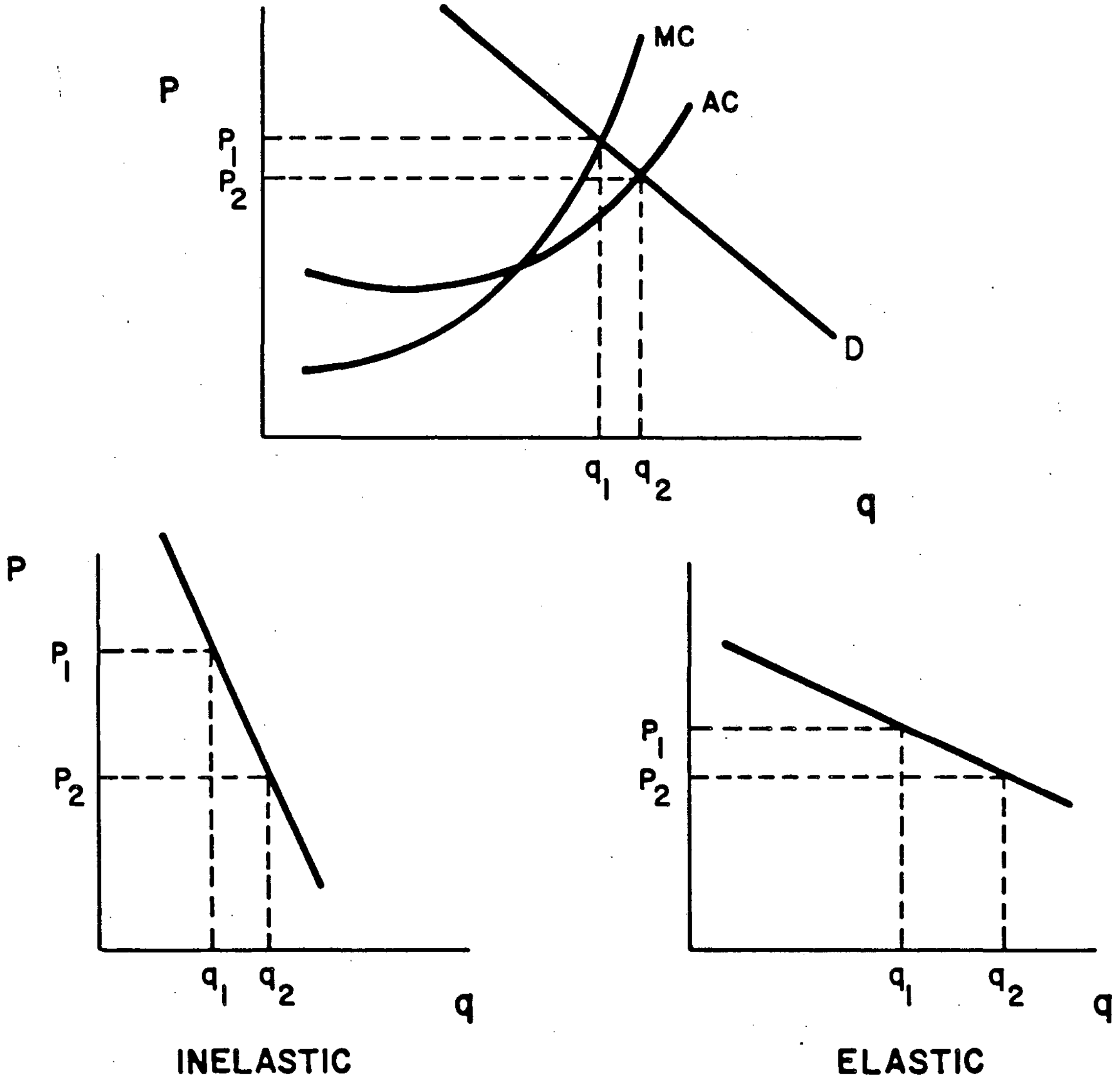

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Figure 7-3 Price versus elastic and inelastic q

To pose these questions with any specificity requires a more detailed view of the production process than we have seen from the theory so far. Sharkey's example of an unstable market is a good step in this direction.

7.3 Example of Market Instability

Sharkey poses these problems in the language of game theory. He uses a notion of the "core" of a particular game to define when a natural monopoly is "sustainable." By sustainability, again is meant whether the natural monopoly firm can deter entry by other firms in its market. As an empirical fact, entry can only be deemed to exist if firms which attempt to enter can actually persist and avoid bankruptcy. Thus the mere existence of small power producers does not mean that the natural monopoly in electricity has been proven unsustainable. It is necessary that these firms survive over time, i.e., recover the cost of their capital investment. To test for this in an abstract way, Sharkey defines a certain co-operative game called "welfare maximization." The players are all consumers <u>and</u> all possible combinations of consumers. The role of firms is reduced to the passive function of merely representing particular consumer coalitions.

In the language of game theory, "solutions" correspond to the notion of equilibrium more commonly used in economics. The core of a game is a special kind of solution in which the welfare of players cannot be improved in whole or in part without damaging some individual. Thus the core is essentially the notion of Pareto optimality. The basic result used by Sharkey is that if the coalition of all consumers is a solution to the welfare maximization game in the presence of a natural monopoly cost function, then the core is non-empty and the monopoly is sustainable. These conditions again boil down to the existence of Ramsey prices which can simultaneously satisfy the revenue requirement exactly and still be less than the cost of substitution for <u>any</u> coalition.

These conditions are very strong, particularly when the cost function is sub-additive but not decreasing. Large, elastic customers or other demand-side constraints can cause the core to be empty when output must cover the whole market. (Alternatively where the market is large relative to scale or scope economies.) To illustrate this concretely, Sharkey introduces an example of a market with random demand where scale economies are not sufficient to provide for a non-empty core. The cost function consists of a fixed component f and a component that varies with output q by a constant amount cq. Formally the cost function can be written

$$C(q) = f + cq. \tag{7-10}$$

It is further assumed that cq can be wholly avoided if the firm chooses to produce no output. Notice that average cost is declining for this function since

$$\frac{C(q)}{q} = \frac{f}{q} + C$$

decreases as q increases.

Sharkey assumes that demand is completely random. It is characterized by a drawing from a uniform probability distribution in which every customer is of the same size and is equally likely to demand one unit of output. Each unit can be sold for a price $= b > c$. To choose an optimal plant capacity under these conditions, it is useful to examine Figure 7-4. The line b_z is the total revenue function for any output z. If we let t = the number of customers, then t also represents the total demand. Let us define output and monopolist's surplus for any realization t of demand.

The demand $t = {}^{cq}/b$ represents the first point at which operating the plant does not induce a loss. If t is less than this point then revenues are less than avoidable cost, so no production occurs. For any $t > q$ the producer's surplus $S = (b-c)q$ since q is the full capacity of the plant. The total expected surplus is just the shaded area in Figure 7-4 which can be written as

$$S(q) = \int_{\frac{cq}{b}}^{q} (bt - cq)dt + (1 - q)\ (b - c)q\ . \tag{7-11}$$

The optimal q will maximize Eq. (7-11). Sharkey calculates this optimal size to be $q^* = {}^{b}/\ (b+c)$.

Now suppose that the firm decides to operate two plants $q_1 + q_2 = q^*$. The total surplus will increase in the manner shown in Figure 7-5. The increased surplus comes from the added flexibility of being able to serve low levels of demand that could not be economically served with a single plant.

For $t < q_1$, there will be a break even point at $cq_{1/b}$ where it becomes economic to operate plant q_1. For $t > cq_{1/b}$ output will be constrained to q_1 until t reaches the break

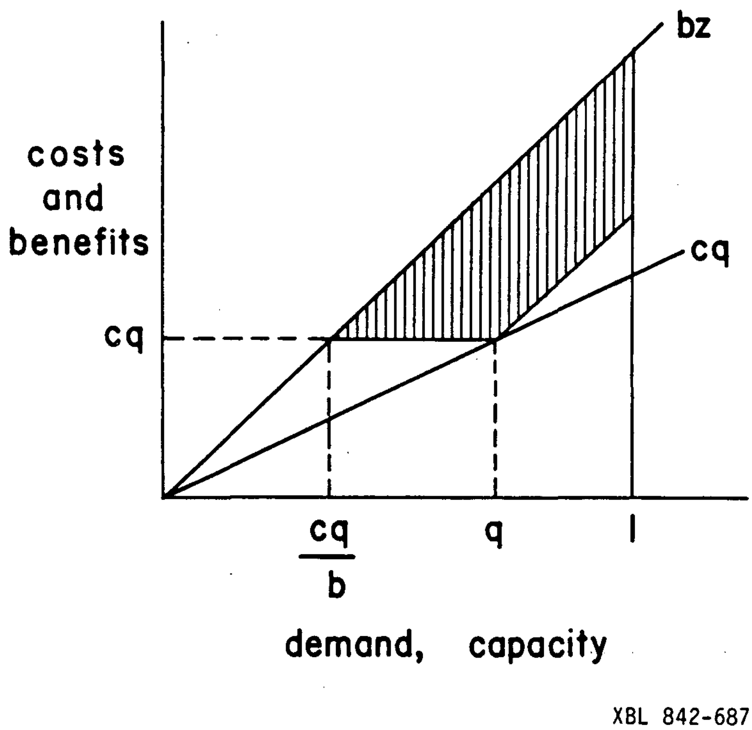

Figure 7–4 Costs and benefits versus demand, capacity

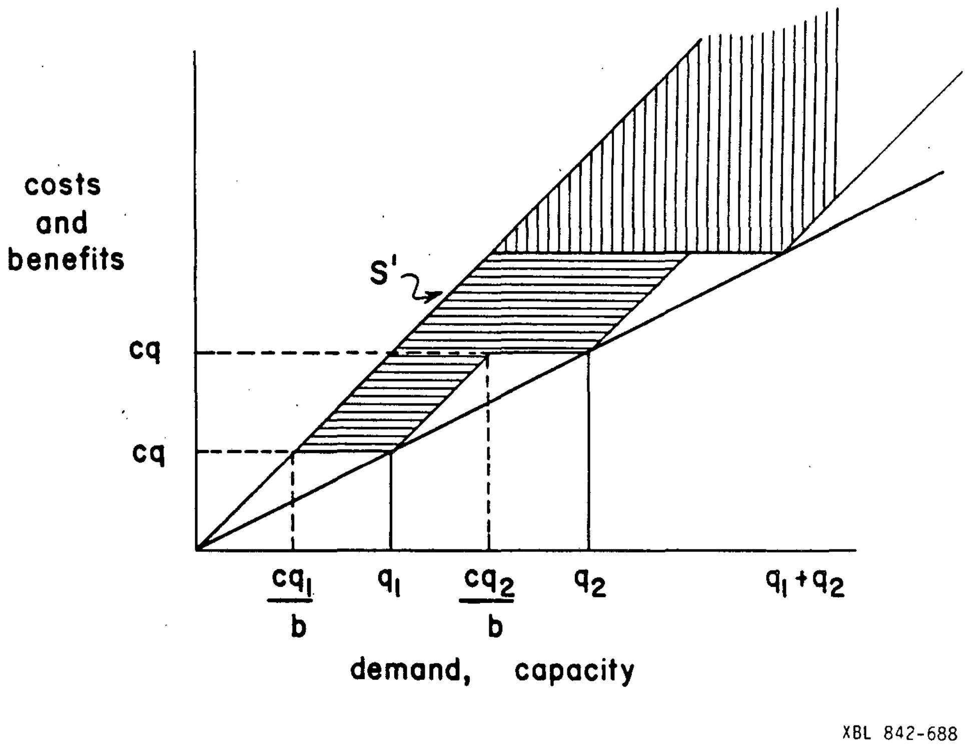

Figure 7-5 Costs and benefits versus demand, capacity

even point for operating plant q_2. This will occur at q_1. For t greater than this value only q_2 operates until cq_2/b when both plants operate. At $t > q_1 + q_2$ we have the same situation as in Figure 7-4 for $t > q$. The economics of multiple plant operation involve trading off the additional surplus S' (the horizontally shaded area) against the added fixed cost, i.e., the scale economy at the plant level. Formally the two plant case is preferrable if

$$(f_1 + f_2) - f^* < S' \tag{7-12}$$

where

f_i =fixed cost for plant of capacity i,

f^* =fixed cost of q^*.

Sharkey then goes on to argue that if multiple plant operation is economic for one firm (i.e., Eq. (7-12) is satisfied), then there is room in the industry for multiple firms. With a multiple-firm industry structure we can compute the cost to serve any coalition of customers using the framework of Figure 7-5. This is shown as C(t) in Figure 7-6. Using this cost function C(t) one can define a characteristic function $V(t) = bt - C(t)$. This function is bounded above by $(b - c)t$, the "operating income" of the industry. It is shown in Figure 7-7.

We can now investigate the core of the game designed to maximize net surplus V(t). This is done be defining an average surplus function V(t)/t. Sharkey then cites a major result from game theory which provides a characterization of stable or sustainable industry structures.

Theorem

The core of the welfare maximization game is non-empty if and only if

$$\frac{V(t)}{t} \geqslant \frac{V(S)}{S} \quad \text{for all } s \leqslant t.$$

From the definition of the surplus function, the condition of the theorem is only satisfied for declining average cost, i.e.,

$$\frac{C(t)}{t} \leqslant \frac{C(s)}{s} \qquad \text{for all } s \leqslant t.$$

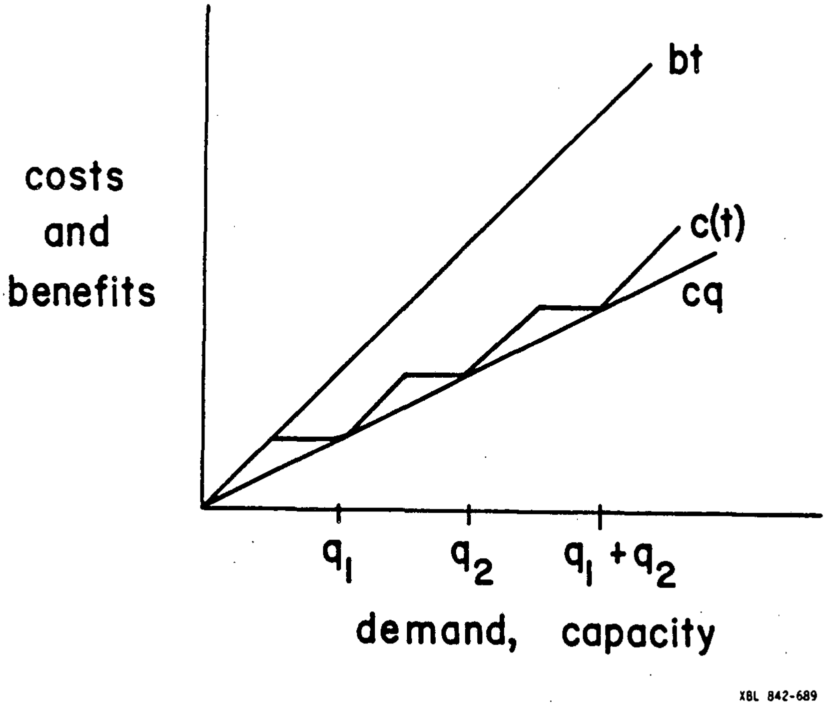

Figure 7-6 Costs and benefits versus demand, capacity

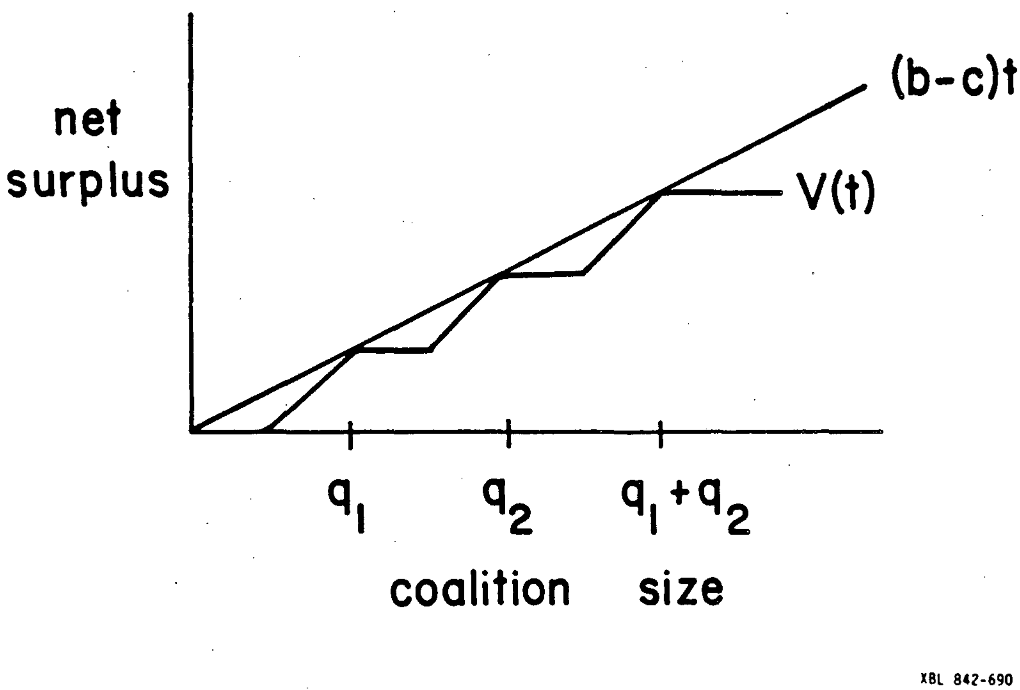

Figure 7-7 Net surplus versus coalition size

Given the flat regions of the cost curve illustrated in Figure 7-6, it is apparent that the two firm industry is not stable.

This result indicates that the original intuitions about natural monopoly and declining average cost were not frivolous, but actually quite robust. The modern theory has identified a region in the cost structure where natural monopoly exists, but in a fundamentally unstable way. The precise nature of the instability illustrated in this example is fairly representative of conditions in the electric power industry today. The supply/demand balance cannot be maintained in light of fluctuating or uncertain demand and inflexible supply side increments. Declining average costs, on the other hand, always implies smooth and "convex" adjustment of supply and demand. There is literally no "room" in the cost structure of the industry for a small low-cost producer. Therefore the natural monopoly can be maintained against entry by other producers. We are clearly not in such a situation, so we must face the complex problems posed by industry instability.

It is at this point that a theory of regulation becomes necessary. What are we to do about unsustainable natural monopolies? Where does the public interest lie in regulating industries of this type? What will regulators do in these situations? To answer these questions requires a wholly different conceptual framework. We must have both an explicit account of what regulation can offer when markets are unstable, and a behavioral theory of regulation in practice. We will sketch these elements briefly. The basic framework we adopt for the first question is based on the theory of commodity price stabilization. Electricity is compared to unstable commodity markets. The role of the regulator is analogous to an agricultural stabilization authority. Our behavioral model will be adapted from the University of Chicago school.

7.4 Stabilization Theory of Regulation

The basic analogy underlying this theory is that regulators function like stabilization authorities in agricultural commodities markets. The existence of marketing boards, price support mechanisms or production quotas are all evidence of the pervasive role of government intervention in agricultural commodities markets. This intervention is deemed necessary to help control randomness of both supply and demand conditions. Both consumers and producers benefit from the reduction of risk that is achieved. We will argue that energy markets also exhibit the supply, price and demand uncertainties characteristic of commodity markets. The regulator is thought of as a stabilizing agency whose services can be used both by producers and consumers.

The theory of regulator policy we will pursue is based on the political equilibrium model of Peltzman. In this model the regulator "sells" his services to various political coalitions, choosing that coalition which maximizes "support" for a particular policy. In the Peltzman model the regulator's "service" is a wealth transfer. In our version of this approach the "service," will be more precisely characterized as stabilization. This will mean any kind of price or quantity stabilization. These actions will result in welfare changes, but the nature of such changes requires some analysis. The view of regulation as stabilization is also expounded in Owen and Braeutigam (1978).

In the Peltzman model the regulator's decision criterion is somewhat vague. Maximizing "support" makes some intuitive sense of the political aspect of regulation, but it is not a concept that is easily amenable to measurement. We will work with a more transparent notion that is directly connected to our specification of the regulators service. The basic concept is the value of stabilization. We assume that regulators provide stabilization services to consumers or producers in proportion to how much each party values this service.

We will end up paying most of our attention to producers as a way to model the investment strategies available to electric utilities in the current unstable market structure. To take full account of the utilities' dilemma, however, we must take explicit account of the world market for fuels. It is this market which initiated the disturbances that have made the electricity cost function increase. With respect to these prices the utility is a consumer, just like any other price-taking buyer. There is no domestic regulatory policy which can permanently stabilize fuel prices. Attempts to achieve this will be shown to have been only wealth transfers.

Let us begin with a brief recap of the price behavior of energy terms subject to differing degrees of regulation during the 1970's. Table 7-1 collects estimates of the coefficient of variation (CV) of energy prices subject to various amounts of regulation. The CV is just the ratio of the standard deviation to the mean of a price series sample. The CV of unregulated oil prices approximates that of other widely traded commodities. Newbery and Stiglitz estimate a real price CV of 26% for cotton, 31% for cocoa and 58% for sugar. Another representation of the real price variation of oil is given in Figure 7-8.

Table 7-1

CV OF ENERGY PRICES 1974-80

	Nominal	Real
Unregulated Oil	.53	.32
Fuel Oil and Coal	.38	.18
Piped Gas and Electricity	.25	.08

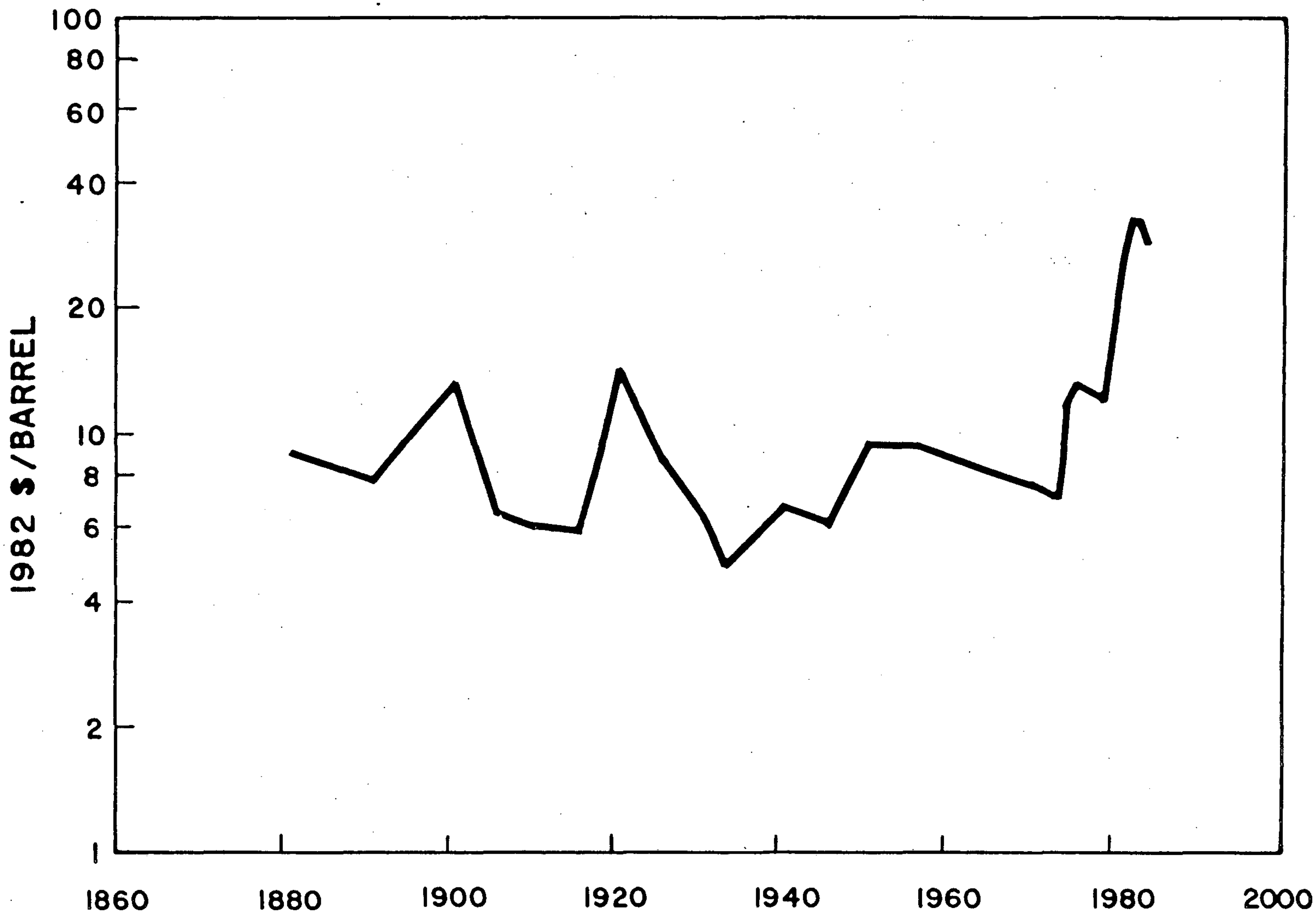

Figure 7-8 Oil prices versus time, 1860 - 2000

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Table 7-1 shows that as the degree of regulation increases the CV of energy prices goes down. This data illustrates the proposition that consumers received price stabilization benefits from regulation during the 1970's. We will estimate the value of that stabilization below. For now, however, it is important to contrast this data with the changes in utility shareholder income during the same period. Table 7-2 gives estimates of the mean and CV of real ROE for utility shareholders before and after the first oil price shock.

Table 7-2 illustrates that shareholder returns went from a high mean low variability level before 1974 to a low mean high risk level after that period. These data together with Table 7-1 suggests that utility regulation during the 1970's transferred energy price risk from consumers to producers. Investors in electric utility shares typically experienced little risk in the period between 1945 and 1974. This stability reflected the sustainable natural monopoly conditions of the time. The economic turbulence of the 1970's was inescapable, however, and regulatory policy effectively placed the burden of this on the producer.

To understand why this occurred and what the future prognosis is, we need an explicit account of the value of stabilization. For this purpose we rely on a simple expression for the consumer value of stabilization derived by Newbery and Stiglitz. The basic idea is that price stabilization reduces consumer income risk in proportion to (1) income variability, (2) price variability, (3) the correlation of price and income, and (4) the consumer's "taste" for risk. Formally this can be written as

$$B = -\rho \sigma_p \sigma_I R, \qquad (7\text{-}13)$$

where

σp =CV of real consumer prices,
σI =CV of real income,
ρ =correlation coefficient of price and income,
R =coefficient of relative risk aversion.

The benefit B is expressed as a fraction of stabilized expenditure on the commodity in question. The CV of prices and incomes are just the quantities estimated in part in Tables 7-1 and 7-2. Clearly the value of stabilizing varies directly with each. The

Table 7-2

ELECTRIC UTILITIES MEAN ROE AND CV

	Mean Real ROE	Real CV
1970-73	5.7%	.16
1974-81	2.5%	.76

correlation coefficient tells you how much price stabilization will affect income. If income increased with prices (positive correlation), the value of stabilization could be negative. The only interesting case occurs when income goes down as price goes up (negative correlation). This is always the case where we are concerned. The most difficult term in Eq. (7-13) is R, relative risk aversion.

Relative risk aversion is an elasticity of marginal utility. It is defined with respect to a utility function U and an income (or wealth) variable Y as follows:

$$R = \frac{-Y\,U''(Y)}{U'(Y)}, \qquad (7\text{-}14)$$

where primes denote derivatives. The form of this definition is constrained by technical features of utility functions (see Arrow, 1970). The basic idea is that preferences with respect to risk change with income. The second derivative of the utility function captures the rate of change of marginal utility. This must be normalized to $U'(Y)$ because utility functions are only defined up to a linear transformation. To make this ratio dimensionless we multiply by Y. Since $U''(Y) < 0$ when the consumer is risk averse, and $U'(Y) > 0$ (income is always desirable) a negative sign is added by convention to make $R \geqslant 0$.

On theoretical grounds Arrow argues that $R \sim 1$. For the simple case of a logarithmic utility function $U(Y) = \log Y$, it is easy to see that $R=1$. Other cases are more complex. The most interesting issues are empirical. What behavior illustrates risk aversion? How do risk preferences change with the level of wealth or income? The evidence reviewed by Newbery and Stiglitz indicates that for low income farmers risk aversion increased as income declines. With increasing prospects for starvation, farmers are less willing to take chances. A practical upper bound in such situations appears to be $R=2$. Conversely, risk neutrality means $R=0$.

Let us now apply the framework of Eq. (7-13) to the history and prospects for regulatory policy in the electric utility sector. The data collected in Tables 7-1 and 7-2 are necessary for this exercise, but not sufficient. In particular we need estimates of σ_I for consumers and ρ for both consumers and utility shareholders. For illustrative purposes we rely upon estimates made by Kahn (1982). It is immediately apparent that the notion of a homogeneous "average" consumer is irrelevant, and that σ_I and ρ will vary substantially across income groups; ρ, for example, is a function of budget share which varies with income. We will focus on low-income consumers. These are likely to place the greatest value on stabilization. We collect parameter estimates and the corresponding benefit estimates in Table 7-3. We provide a basic estimate for each group based on 1981 conditions, plus a variation which represents the likely 1974 situation.

The base case in Table 7-3 expresses concretely the risk transfer imposed by regulation in the 1970's. Because the consumer price variation is small, there is little additional benefit even to the low-income consumer of additional stabilization. If prices to consumers had not been stabilized, and had reflected the world market ($\sigma_p = .3$), then consumers would derive substantial value from stabilization. At the time of the first oil price shock, regulators undoubtedly perceived the utility's ability to bear risk as greater than that of consumers. If we use the pre-1974 value of σ_I in Eq. (7-13), to the utility shareholder B falls by almost a factor of 5. Similarly, the regulator contemplating the consumer's position in 1975 if costs were completely passed through would perceive a greater stabilization value for consumers than shareholders (case 2 vs. base case). Thus the principle that regulation stabilizes on behalf of the party who receives the greatest benefit accounts for past behavior. The base case results for the situation in the 1980's suggests that the pendulum must swing back in favor of producers. Given this hypothesis, it is useful to ask what particular form of stabilization is in the producer's interest. To understand the issues, we need a model of the producer benefit from stabilization.

Newbery and Stiglitz derive a stabilization value expression for producers which complements Eq. (7-13), but is considerably more complex. The general procedure is to find a monetary sum that the producer would be willing to pay to reduce income risk to some specified level. The calculation proceeds by equating expected utility in the unstabilized case with the expected utility of stabilized income minus the stabilization monetary equivalent B. The relevant income variable is total revenues, i.e., price times quantity. Solving the algebraic equation yields the following expression

$$\frac{B}{\bar{Y}} = \frac{\Delta\bar{Y}}{Y} + 1/2R\,\Delta\,\sigma_y^2\,, \qquad (7\text{-}14)$$

where

$\bar{Y}$ = expected total revenue in the unstabilized case,

$\Delta\bar{Y} = \bar{Y}_s - \bar{Y}$, where $\bar{Y}_s$ = expected total revenue

Table 7-3

CONSUMER VALUE OF INCOME RISK STABILIZATION

	Low Income Consumer		Utility Shareholder	
	Base Case	Case 2	Base Case	Case 2
σ_p	.08	.3	.3	
σ_I	.30		.76	.16
ρ	-0.8		-0.7	
R	2.		1.	
B	.038	.144	.160	.034

after stabilization,

$\Delta \sigma_y^2$ = difference in $(CV)^2$ of total revenue after and before stabilization.

The first term in Eq. (7-14) is called a tranfer benefit, since any change in average total revenue for producers is matched by an equal change for consumers. The second term is the efficiency or risk benefit. It measures the welfare increase of reducing producer risk.

Eq. (7-14) can be quantified in particular cases by making some assumptions about the shape of the underlying distributions. The most tractable case involves using the lognormal distribution for output and total revenue (income). The essential properties of the lognormal distribution are shown in Figure 7-9. Figure 7-9 shows that lognormal variates always take positive values. The usual case is positive skewness (case a) where the mean is substantially above the median. A shape such as case (a) is plausible to use for income distribution, and this function is often used for that purpose. Utility output has also been shown to exhibit positive skewness (Kahn, 1979). Case (b) will turn out to represent the price distribution. This will conveniently represent the tendency toward high prices (i.e., more probability mass above the mean than below it). Positively skewed output implies negatively skewed prices in this case because of price elasticity, i.e.,

$Q = P^{-\varepsilon}$, for elasticity ε assumed positive by convention.

If Q is log-normally distributed as in case (a), then $p = Q^{-1/\varepsilon}$ will show the shape of case (b).

Using these assumptions, Newbery and Stiglitz derive the following expression for the case of complete stabilization with repsect to B_T, the transfer benefit

$$B_T = \frac{\Delta \bar{Y}}{Y} = 1/2 \ (\varepsilon * - 1) \ \sigma_p^2 \ . \qquad (7\text{-}15)$$

Inspection of Eq. (7-15) clearly shows $B_T < 0$ for $\varepsilon < 1$. This means that if demand is not very elastic stabilizing prices benefit consumers because customers will end up paying less frequently at high prices for more or less the same quantity. Conversely, where elasticity is high, producers benefit from reducing the frequency of very high prices since the sales loss is more than proportional to the price change.

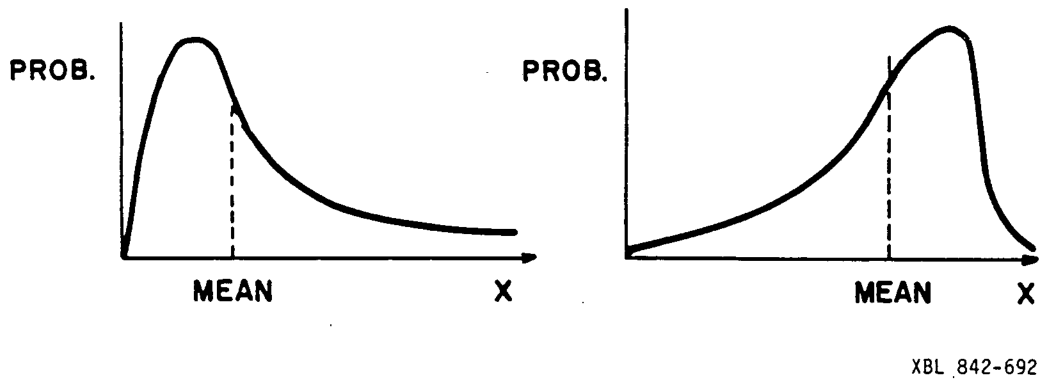

Figure 7-9 Log normal density function

Eq. (7-15) has a natural generalization to the case of partial instead of complete stabilization. Suppose that partial stabilization reduces the CV of prices to a fraction (1-Z) of its original value. Z measures the degree of stabilization, with Z=0 corresponding to none and Z=1 representing perfect stability. Then Eq. (7-15) can be written

$$B_T = 1/2\ Z\ (\varepsilon - (2-Z))\ \sigma\ p^2 \qquad (7\text{-}16)$$

The effect of this generalization is to change the point at which B_T changes sign. Figure 7-10 illustrates the effect of the parameter Z on B_T. The basic trend shown here is for partial stabilization is to decrease the absolute magnitude of B_T, but to increase the value of price elasticity at which $B_T > 0$.

Figure 7-10 is useful for analysis of the transfer benefits associated with utility conservation programs. Generally speaking producers lose in these transfers unless the market elasticity is high ($\varepsilon > 1$) and stabilization is substantial ($Z \sim 1$) . There may be submarkets of utility service in which these conditions obtain. One example might be residential electric space heating. Utilities estimate long-run elasticities of 1 or more in this sector. Promotional rates for this market can be construed as stabilization policies which prevent transfer losses or imply tranfer gains.

This case is one in which high elasticity is given, and rate incentives provide stabilization. Additional conservation programs have the effect of increasing the elasticity. Weatherization financing or appliance rebates essentially accelerate the consumer response to price. As our cost-effectiveness studies indicated the benefit to producers depends upon general rate-making policy (the avoided cost minus lost revenue criterion for example). In general, the regulator chooses a stabilization policy first through rate levels and tariff design. Conservation programs do not impact these decisions directly. Instead conservation just increases elasticity within a given stabilization framework.

In terms of Figure 7-10, the parameter Z is typically chosen by the regulator. Table 7-1 indicates that the value chosen during the 1970's was high, between 0.6 and 0.8. Assuming a price elasticity ε = 0.5. Z = 0.7 and σ_p = .32, then B_T = -0.028; i.e., the transfer loss is about 2.8% of revenue. Conservation programs can reduce this loss (by increasing ε), but to a lesser extent than policies which de-stabilize prices in general. This can be shown by examing the derivatives of B_T with respect to Z and ε. These are shown in Eqs. (7-17) and (7-18), i.e.,

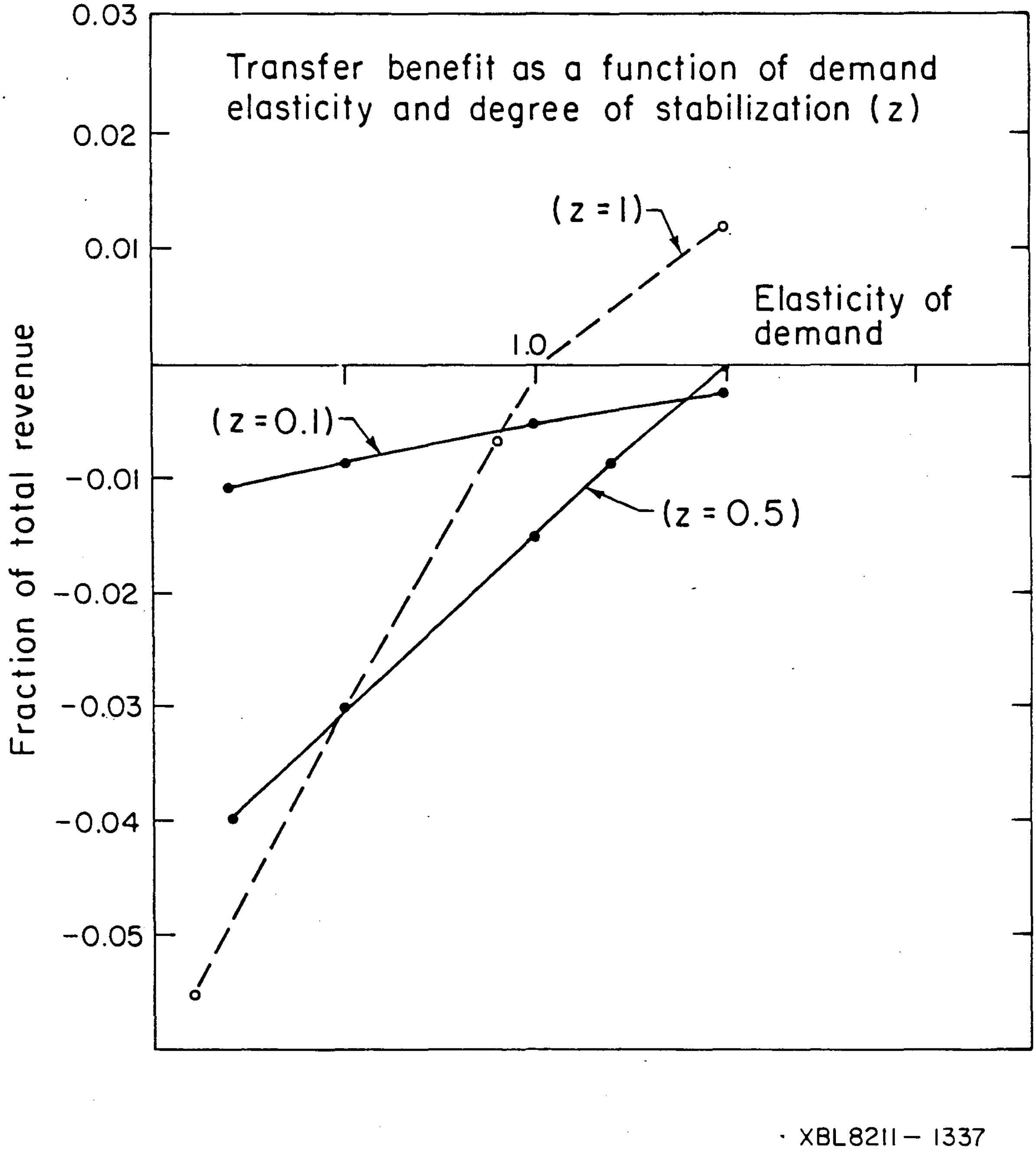

Figure 7-10 **Transfer benefit as a function of demand elasticity and degree of stabilization**

$$\frac{\partial B_t}{\partial \epsilon} = 1/2 \; Z \; \sigma_p^2 \, , \tag{7-17}$$

and

$$\frac{\partial B_T}{\partial Z} = (1/2\varepsilon - 1+z) \; \sigma_p^2 \tag{7-18}$$

The absolute magnitude of $\frac{\partial B_T}{\partial Z}$ is greater than $\frac{\partial B_T}{\partial \varepsilon}$ as long as $Z > 2- \varepsilon$.

These results indicate that with respect to transfers, utility conservation programs compete with de-regulation or de-stabilization of prices. This competition can be made more explicit by considering the producer's investment strategies and choices. These choices are best analyzed by considering the risk benefit term in Eq. (7-14). Producers typically retain the risk benefit. It is, after all, a form of stabilization designed to encourage investment. The producer will know the price or quantity he needs stabilized to reduce investment risk in a particular circumstance. Thus for "business-as-usual" regulated utility production the inclusion of CWIP in rate base is an appropriate stabilization scheme. We will investigate the value of stabilization (not its form) for various utility production strategies. To do this systematically we need an analogue to Eq. (7-16) for the risk benefit, B_R. Newbery and Stiglitz derive such an expression for the case of log-normally distributed supply and demand uncertainty. Their expression for the risk benefit in this case is

$$B_R = 1/2 \; RZ \left[(2 - Z) \; \sigma_{po}^2 + 2 \; r_{\sigma\sigma po} \right], \tag{7-19}$$

where

σ = CV of output,

σ_{po} = CV of unstabilized price,

r = correlation co-efficient of log P on log Q,

and

z = degree of stabilization.

It is useful to illustrate the sensitivity of Eq. (7-19) to parameter values. Figure 7-11 is helpful in this regard. It shows that the sign of the parameter r is the most signifi-

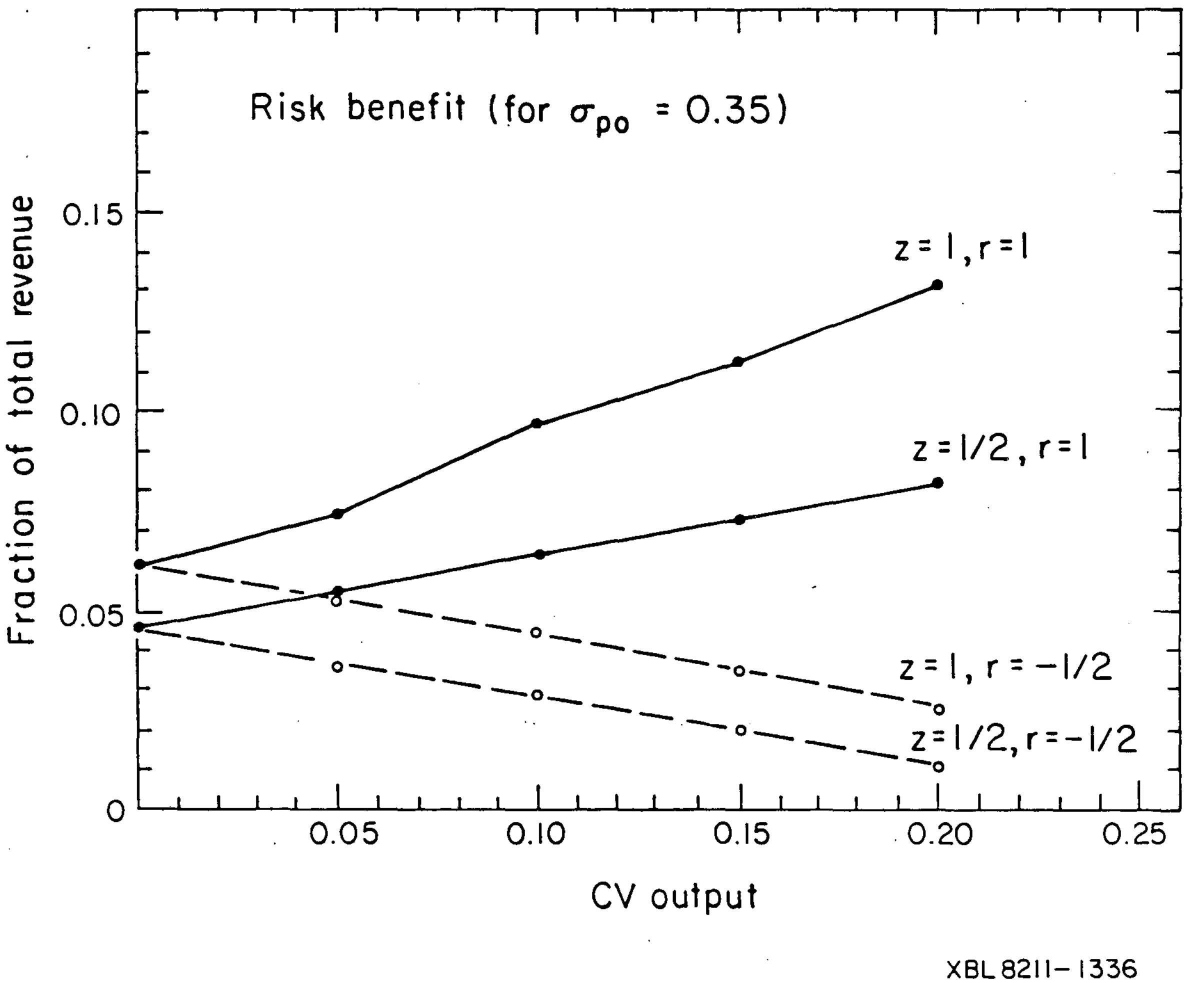

Figure 7-11 **Fraction of total revenue versus risk benefit**

cant contributor to variation in the magnitude of B_R. This parameter is similar to the price elasticity of the market. When it is negative, then the market itself is stabilizing income to some degree because fluctuations in price or quantity are offset by the "elasticity" adjustment. If price goes up, quantity goes down; therefore their product (i.e., income) stays relatively stable. Similarly in the case of price going down. The case of $r > 0$ means that income fluctuations are not damped by the market, but are exaggerated. In this case the value of stabilization is great.

To analyze producer preferences, we examine B_R for different producer roles where different parameter values are relevant. It is clear, for example, that utility conservation programs must have $r < 0$, since they are elasticity enhancing. To model supply side production strategies, we distinguish a "business-as-usual" role from the role of unregulated producer. The latter can be thought of as a Qualifying Facility under PURPA, or an unregulated utility subsidiary in this role. There is evidence that utilities are interested in this possibility, so it deserves general treatment. Examining the unregulated producer role will also allow us to quantify the competition between deregulation and utility conservation programs which our analysis of the transfer benefit revealed.

Table 7-4 summarizes the parameter values we will use in Eq. (7-19). These are crude estimates and imply the need for sensitivity analysis. Nonetheless the values are plausible if not precise. Let us begin with the parameter $r = \text{corr}(\log p, \log Q)$. We have already argued that $r < 0$ for utility conservation programs. The absolute magnitude should approximate the price elasticity. We test $r = -1.0$ and $r = -0.6$. For unregulated production we expect $r = 1.0$. The regulated producer should have $r > 0$ also. Kahn has estimated a value of $r = 0.8$; we test that and $r = 1.0$.

The CV of output should be measured at the "plant" level for all alternatives. For central station power plants (the regulated producer) one can estimate the CV of plant capacity factor. A recent statistical study of this variable for new coal plants identified 60% as the mean, with a high = 80% and a low of 38% (Perl, 1981). Assuming this range covers two standard deviations implies CV = .15. We adopt this as our base case. If the high and low span only 80% of the probability, then CV = .25. The CV of output for unregulated production is harder to estimate. Some technologies like wind or hydrogeneration could have CV = .30. Cogeneration, on the other hand, might be 2%. For simplicity we assume CV of output is similar for both supply roles, regulated and unregulated.

Table 7-4

CV PRICE AND OUTPUT FOR VARIOUS PRODUCERS AND CONSERVATION PROGRAMS

	CV Price	CV Output	r = low (log p, log q)
Regulated Producer	CV Coal = .18	Base = .15	0.8 - 1.0
Unregulated Producer	CV marginal Price = .35	Same as regulated producer	1.0
Utility Conservation Programs	CV marginal Price = .35	Less than regulated producer	-.6 - -1.0

The output of utility conservation programs must be measured in the aggregate because it is the aggregate supply/demand framework in which their value must be assessed. It has been argued that these programs should be more predictable than supply project output. There are, however, many unsettled measurement problems associated with utility conservation programs. Even if they were resolved, there is very little evidence on the CV of output. We will assume that the CV in this case is less than for supply roles, and test for sensitivity.

The CV of unstabilized prices should be the marginal utility cost in all cases. For conservation and unregulated production the CV of oil prices is a good proxy. Statistical studies of nuclear power plant capital costs also reveal a real price CV in excess of 30% (Komanoff, 1981). The case of a coal plant (regulated production) is somewhat different. The unstabilized price can be thought of as the fuel itself, or in the case where the coal plant displaces oil, then it is the net of oil and coal price instability. In either case the numerical value is about the same.

Table 7-5 summarizes the stabilization risk benefit results. It is clear from this that unregulated production is the most favored role. The stabilization value is greatest here under any of the listed assumptions about the CV of output. This is a plausible result because this case represents putting an "excess profit tax" ceiling that is associated with conventional regulation..

The competition between utility conservation programs and traditional production depends on parameter values. If the CV of conservation "output" is small enough, then it is the favored alternative. On the other hand, if this parameter is large, then conservation is not only less attractive, it may even be harmful. An unpredictable conservation program may increase the supply-demand imbalance, thereby increasing producer income risk.

This suggests that the modularity or incremental nature of conservation program output may turn out to be its most important feature. The key question at this stage is to what degree the "output" can be controlled.

Table 7-5

RISK BENEFIT FOR GENERIC PRODUCTION ROLES AND DEGREE OF STABILIZATION

		z = 1		z = .05	
		r = 1.0	r = 0.8	r = 1.0	r = 0.8
Regulated Producer	σ = .10	.034	.030	.021	.019
	σ = .15	.043	.038	.026	.023
	σ = .25	.061	.052	.035	.030
Unregulated Producer	σ = .10	.096		.064	
	σ = .15	.113		.064	
	σ = .25	.149		.090	
		r —1.0	r = -0.6	r = -1.0	r - -0.6
Utility Conservation Programs	σ = .05	.044	.051	.037	.045
	σ = .10	.025	.040	.029	.036
	σ = .020	-.009	.019	.011	.025

7.5 Future Prospects

It now appears that no simple dichotomy exists between de-regulation and business-as-usual for the electric utilities. It is clear that more competition exists in the market for electricity generation, and that conservation will be a powerful force in the long run. These forces tend to de-stabilize the utility. The two basic questions facing the industry are: What should management do about this this? and, What is a socially desirable regulatory policy?

The value of regulatory stabilization for small power production has been shown to be quite large. This suggests that QF's in the long run may find a permanent place as producers. Utilities have only two choices in this area. They can fight or they can join. One way to fight QF's is with conservation. If the utilities can manage demand reduction properly, they reduce the value of QF production and hence its market share. This is a risky strategy, however, since too much conservation can induce an unprofitable "excess capacity" situation. The alternative is to join the QF industry by becoming "unregulated" producers themselves. This option has been authorized in New York and is under discussion in industry and government circles (Newmark and Cooper, 1984). It would probably involve a change in PURPA, but that is no major barrier if a policy consensus exists.

It is the policy issues, however, which are most indeterminate. We have characterized the electricity market as uncertain and unstable. This makes it harder to discern a clear direction of evolution. Moreover, it suggests that conditions may vary regionally depending on variations in the supply and demand balance. The job of regulation is harder now that shareholder and consumer interests are more in conflict than they were when costs were declining. From the consumer perspective, for example, large scale conservation might be the least cost alternative. It is unlikely that shareholders and managemeet would willingly shrink the market with such a strategy. This is particularly true where the utility's large customers are leaving the system to become QF's.

The policy outcome will be determined largely by local economic and political conditions. It is not clear what the stable or sustainable configuration of electricity supply and demand will be, or indeed, if there is just one such outcome.

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