RESIDENTIAL BASELINE INVERTED RATES
ANALYSIS OF THEIR APPLICATION IN WASHINGTON STATE

Prepared For

The Washington State Senate
Committee on Energy and Utilities

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March, 1981

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EXECUTIVE SUMMARY

The Pacific Northwest has long enjoyed electric rates that are among the lowest in the Nation, based on inexpensive power generated by the region's enormous hydroelectric system. However, the region's major hydro resources have been nearly fully exploited, and regional demand for electrical energy has outstripped the hydro system's capacity. The region's utilities have embarked upon an ambitious program to construct nuclear and coal-fired power plants to meet growing demand. However, many of these plants are experiencing lengthy delays and tremendous cost overruns.

As a result, consumers in the region face rapidly escalating electricity bills and almost certain electricity shortages in the coming decade. There is general agreement that conservation and certain renewable energy applications represent the only option for avoiding impending electricity shortages. Furthermore, there is considerable evidence that many conservation actions can "provide" energy much more cheaply than new nuclear or coal-fired plants.

However, a number of institutional obstacles stand in the way of the timely and widespread adoption of cost-effective conservation measures. This report examines one such obstacle--traditional electric rate structures for residential customers.

Further, this report evaluates a number of alternative rate structures according to three traditional ratemaking criteria and in light of the increasing cost conditions facing the region's utilities.

The results of this analysis may be briefly summarized as follows:

(1) Traditional declining block rate structures, which provide decreasing prices per kwh as consumption increases, are inappropriate during times of increasing costs. Declining block rates mislead consumers by indicating that costs <u>decrease</u> as consumption <u>increases</u>, when the opposite is true.

These misleading prices cause consumers to make uneconomic or inefficient decisions regarding fuel choice, electrical energy use and conservation. That is, declining block rates encourage wasteful use of electric energy in times of increasing costs.

(2) Electric rate structures based on average costs--flat rate structures--also encourage inefficient use of electric energy during times of increasing costs. Although not as misleading as declining block rates, flat rates based on average costs also mislead consumers by indicating that costs remain relatively stable as consumption increases.

(3) Pure marginal cost rate structures, which would price all electric energy at the cost of energy from new energy sources, would lead to economically efficient decisions regarding the choice of fuels, the selection of heating and cooling equipment and appliances, and choices between energy use and conservation measures. However, pure marginal cost rates would result in considerable excess revenues for utilities, severe cost increases for consumers, and would require some mechanism for distributing excess revenues back to consumers.

(4) A baseline inverted rate structure would result in more efficient (e.g., less wasteful) use of electricity, while avoiding the problem of very large excess revenues to utilities. A baseline inverted rate structure would price the initial or "base block" of electrical energy at the cost of inexpensive hydroelectric power to the utility. Electric energy consumed in excess of this base block would be priced at a level more closely approximating the marginal cost of electric energy; that is, the cost of power from new thermal power plants. Such a rate structure would provide the vast majority of consumers with more accurate price signals by pricing energy consumption over the base block closer to its marginal cost and closer to the cost of alternative fuels.

A baseline inverted rate structure has been successfully adopted by Seattle City Light. In addition, the Washington State Utilities and Transportation Commission recently promulgated an order requiring all investor-owned utilities to adopt baseline inverted rate structures at subsequent rate orders. Presently, Puget Power has adopted a baseline increasing block rate structure under the state UTC's order.

Simulations developed for this report and presented in Chapter 4 indicate that, under assumptions consistent with the results of empirical research, baseline inverted rates will result in significant long-run electrical energy savings. Even under "worst case" (and least likely) assumptions, slight decreases in electrical energy use will result. These simulations also indicate that some minor adjustments in the rate structure may be necessary during an implementation phase to ensure that total revenues cover but do not exceed a utility's total costs.

CHAPTER 1: INTRODUCTION

As newspaper headlines and rapidly escalating electric bills testify, the Pacific Northwest has embarked upon a new era in the generation of electric power. The region's major sources of inexpensive hydroelectric power have been almost fully exploited, and the utilities in the region have embarked upon an ambitious and costly program to construct nuclear and coal-fired generating facilities. This transition to a new era has been characterized by considerable debate about the shape of the region's electric energy future. Many of the region's utilities argue that additional nuclear and coal-fired capacity will be needed in the long run to meet growing electrical demand in the region.[1]

Others argue that there are numerous conservation measures and alternative energy sources that are both more cost-effective and environmentally sound than new nuclear or coal-fired facilities. They also argue that these conservation measures and alternative energy sources can be implemented before new central generating facilities can be brought on-line.[2]

However, there is general agreement on both sides of the debate that something must be done over the short term to avoid electrical shortages during the 1980's.

This report will examine the effect of electricity rate structures on the demand for electricity, to identify how electric rate reform can contribute to solving the region's short and long term electric energy problems. The remainder of this chapter lays out the regional context for examining the role of electric rate structures. Chapter 2 discusses the objectives of, and concepts and issues fundamental to, electric rate design. A number of alternative rate structures are then evaluated in terms of the various objectives of rate design. This evaluation suggests that an inverted residential rate structure is the most appropriate for both meeting traditional utility objectives and the current problems facing the region. Chapter 3 begins with a brief summary of the existing residential rate structures of electric utilities in Washington. This chapter concludes by examining in greater detail inverted residential rate structures adopted in Washington and in other parts of the country. Finally, Chapter 4 presents and evaluates a proposal to adopt an inverted residential rates structure in this state.

1.1 Historical Context

Historically, the energy situation in the Pacific Northwest has been shaped by two important features unique to the region. The most important of these is the tremendous hydroelectric potential of the region's river systems, estimated at 40% of the hydro potential of the entire nation.[3] The second feature is the unique institutional arrangement that has evolved between the federal government and public and private utilities to harness the region's hydroelectric potential.

The Bonneville Power Act, enacted in 1937, set the stage for the development of the unique institutional structure in the Pacific Northwest for the generation and distribution of electric power. (16 U.S.C. 832-832D.) The Act created the BPA and authorized it to work with the Bureau of Reclamation and Army Corps of Engineers to construct hydroelectric facilities and generate and market power from these facilities.

Since that time, the region's hydroelectric capacity has grown to about 24,250 megawatts, representing about 78% of the region's total generating capacity in 1978. The 33 dams of the Federal Columbia River Power System accounted for about 46% of the total hydroelectric capacity, with public and private utilities providing the remainder.[4] From the first days of its development in the late 1930's through the late 1960's, the capacity of the region's hydroelectric system was generally in excess of regional demands. This factor, coupled with technological progress, led to a situation characterized by what economists call declining marginal costs. That is, excess capacity and economies of scale in generation and transmission provided a situation where increases in total electricity sales led to decreasing costs per unit (kwh) of electricity.[5] In this situation, all consumers could benefit from increased electricity sales through lower costs per kwh. Thus, utilities typically adopted "declining-block" rate structures designed to promote electricity consumption by pricing additional blocks of electricity at declining rates.

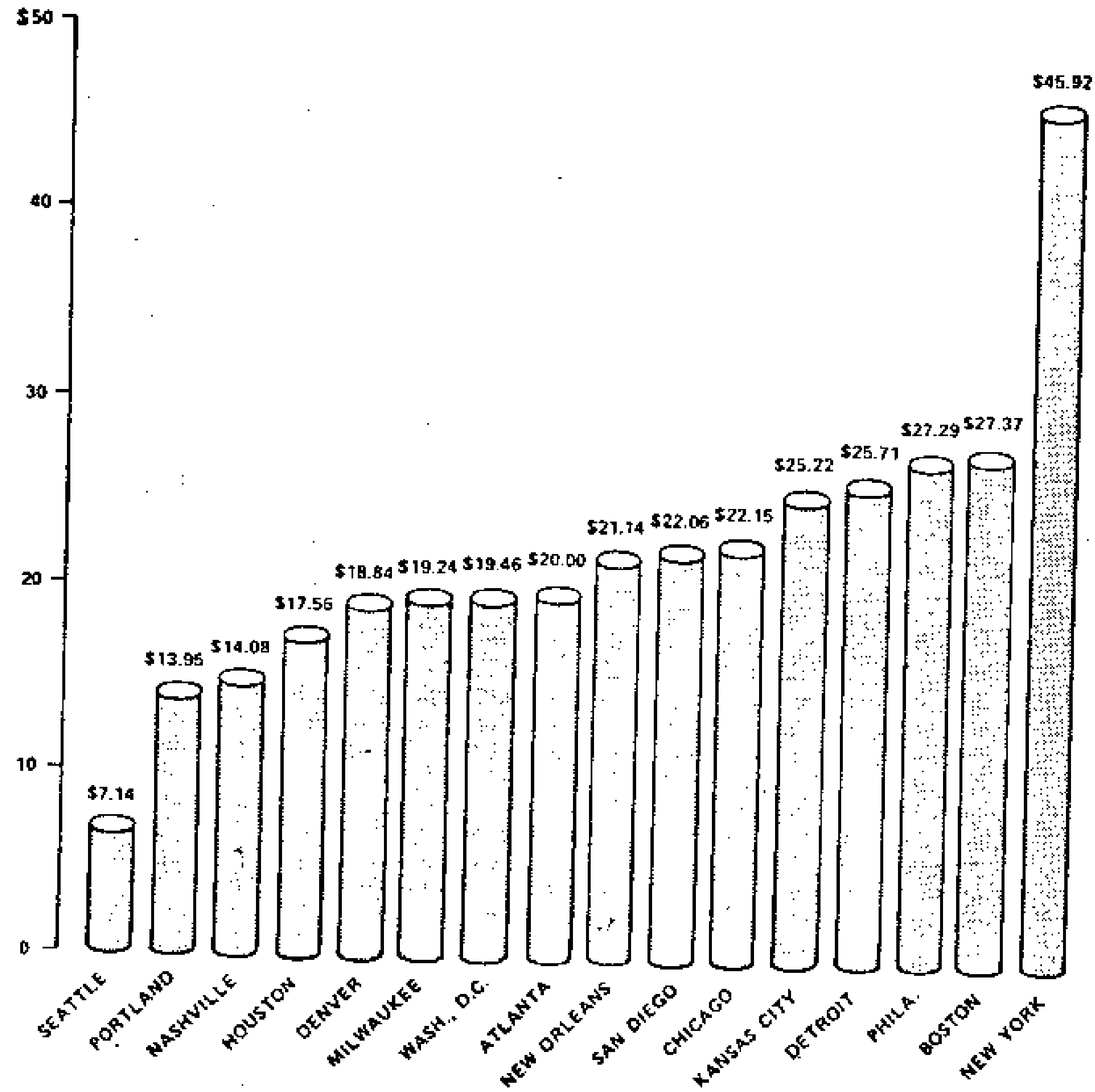
The region's unique combination of natural resources and institutional arrangements provided electricity rates that were, and continue to be, among the lowest in the nation. This is illustrated by Figure 1-1, which shows the average cost of 500 kwh to residential users in 1977 in selected cities across the U.S. These low costs have, in turn, led to high levels of electric energy consumption in the region. This is illustrated in Figure 1-2, which shows average annual residential electrical consumption in cities across the U.S. Note that the two cities with levels of consumption comparable to those in Seattle or Portland (Nashville and Houston) both also have relatively inexpensive electricity and high air conditioning loads in summer. Indeed, the figures shown for Seattle and Portland are likely to understate average residential consumption in the region because the proportion of recent residential construction (the vast majority of which is heated electrically) is likely to be much higher outside the city limits of relatively built-up cities like Seattle and Portland. Additionally, the low cost and availability of electric power in the region has over the years led to a high concentration of industries that use large amounts of electric power. Foremost amonst these is the region's aluminum smelting and refining industry, which currently accounts for about one-third of total national capacity in that industry[6] and consumes about one-fourth of the total electricity generated in the region.[7]

1.2 Current and Future Trends

The electrical supply situation in the region began to change dramatically in the late 1960's. At that time, most of the region's major sources of hydropower were fully developed, while demand was projected to grow very rapidly during the decade of the '70's. The utilities' response to this situation was the formulation of the hydro thermal power program (HTPP)

FIGURE 1-1

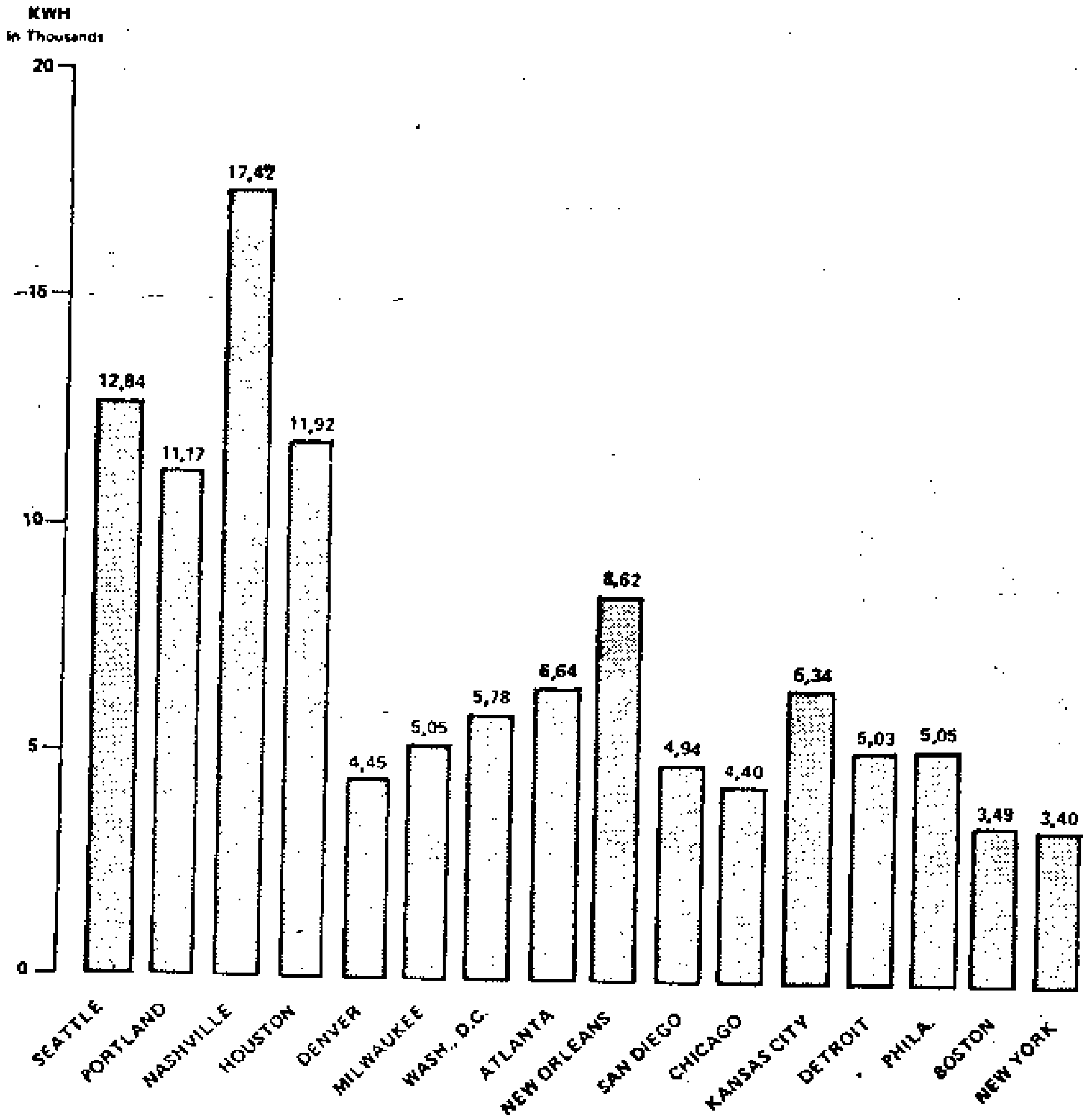
COMPARATIVE ELECTRIC BILLS FOR SELECTED CITIES
(JANUARY 1977 BILL FOR 500 Kwh RESIDENTIAL USAGE – TAXES INCLUDED)



Source: TVA

FIGURE 1-2

COMPARATIVE AVERAGE ANNUAL ELECTRICAL CONSUMPTION FOR C.Y. 1976 - RESIDENTIAL USAGE



SOURCE FEDERAL POWER COMMISSION

in 1968. Originally, the program envisioned the construction of 20 nuclear and 2 coal-fired plants to meet the projected rapidly increasing demand for electricity in the region by 1990.[8]

Events since 1968 have dramatically altered the HTPP. Some plants, like the proposed Skagit and Pebble Springs nuclear plants, have been effectively blocked by environmental and safety concerns. The nuclear plants under construction, WPPSS units 1-5, have experienced dramatic cost overruns and lengthy delays.[9] Finally, the rate of growth in electricity demand during the 1970's was much slower than it had been forecast in the previous decade.[10]

One important legacy of the 1970's will be dramatically higher prices for electric energy in the region. Much of the recent and future price increases will be necessary to pay for the five WPPSS nuclear plants. The estimated cost of constructing these plants has increased by 160%, and has a 80% chance of going even higher.[11] In 1979, the Bonneville Power Administration increased the wholesale cost of power by 90%, much of which was attributable to increased costs due to three of the WPPSS plants. The revenue requirements, adjusted for inflation, of many of the participating utilities in the WPPSS plants will double from 1978 to 1990 in order to pay for the power generated by these facilities.[12]

In addition to substantially higher electrical costs, the region faces a high risk of electrical energy shortfalls in the 1980's. This, too, is due in large part to the lengthy delays in construction of the WPPSS plants. In each of the next ten years, critical water conditions would cause available electrical energy supply in the region to fall below projected regional demand. Indeed, a shortfall is almost certain to occur at sometime during the next decade.[13]

1.3 Challenges Facing the Region

These trends in electrical energy price and supply present citizens and policymakers with a number of important challenges. First, what can be done to avoid, or minimize, the potential social and economic disruption of shortfalls in electrical energy supply in the coming decade? Second, what actions can be taken to minimize the social and economic disruptions of rapidly increasing electrical energy costs? Finally, what changes should be made in the institutional setting within which electrical energy is produced, distributed and consumed, to encourage the decentralized decisonmakers in this setting to develop the most efficient--least cost--mix of energy sources (including conservation) for meeting regional energy demands?

It is generally acknowledged that conservation--using electricity more efficiently to obtain the same benefit out of a lower level of consumption--holds considerable promise for meeting the challenges facing the region in the coming decade and beyond. The potential for using electricity more efficiently, without "freezing in the dark", is substantial. A recent BPA survey indicates that there are many conservation actions that are clearly cost-effective relative to the cost of energy from new power plants, that have not been undertaken in Washington homes.[14]

There have been several analyses of residential conservation potential in the Northwest. One recent study identified a potential for saving 821 average megawatts per year by the year 2000 in the state of Oregon through weatherization, heating system retrofits (including solar), water heating efficiency improvements, and improved new building practices in the residential sector alone.[15] The vast majority of this potential is relatively inexpensive compared to the cost of energy from new plants. Extrapolating the Oregon estimates to Washington yields almost 1,400 average megawatt savings per year by 2000, almost the equivalent of the output of two 1,200 megawatt capacity power plants.

The NRDC report referenced earlier estimates that, by 1995, the electrical energy savings potential of cost-effective residential conservation and solar measures is about 2,700 average megawatts per year.[16]

If conservation has such potential and is so attractive economically, why is it apparently so difficult to implement? There are a number of reasons. Most stem from the fact that conservation actions are decentralized, requiring thousands of decisions by thousands of individual consumers. In making these decisions, the consumer faces many factors: uncertainty about what should be done and how; difficulty in financing; competing demands for his or her dollar; and, of primary importance for this study, <u>misleading market signals</u>.

The pricing of electricity in the Northwest has historically been based on averaged costs, melding the costs of expensive and inexpensive resources. When there is no significant difference in the cost of various resources, this practice is not critical. When, however, differences in the costs of existing and new resources are large, as is the case today, melding these costs masks the true cost of consumption from the consumer. Individual consumers will make decisions between conservation actions and increased consumption that are economically rational from the individual consumer's point of view, but that are economically inefficient from the perspective of the state or region as a whole.

The purpose of this report is to examine the ways in which electric utility rate reform can contribute to meeting the challenges facing the region by promoting economically efficient conservation. Certainly, rate reform does not represent a panacea for the region's electrical energy problems. However, this report will show that rate reform can contribute in an important way toward their solution.

The focus of this report is restricted in two important ways. First, only residential electrical rate structures are examined: commercial and industrial rate structures are beyond the scope of this report. Second, this report describes, but does not analyze, the effect of peak load (either seasonal, or time-of-day) rate structures. As described in Section 2.3, peak load rate structures are less appropriate in the Pacific Northwest than in other regions of the country.

FOOTNOTES TO CHAPTER 1

[1] Pacific Northwest Utilities Conference Committee (PNUCC), West Group Forecast of Power Loads and Resources: July 1980-June 1991. Supplement 1. (July, 1980), p. 3.

[2] Cavanagh, Ralph C., Lawrie, Mott, J. Rodger Beers and Terry L. Lash. Choosing an Electric Energy Future in the Pacific Northwest: An Alternate Scenario. Washington, D.C.: U.S. Department of Energy, (August, 1980).

[3] Bonneville Power Administration (BPA), The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System: Summary Report. Portland: U.S. Department of the Interior, (August, 1977), p. 1.

[4] BPA, Final EIS: The Role of the Bonneville Power Administration in the Pacific Northwest Power Supply System. Washington, D.C.: U.S. Department of Energy, (December, 1980), p. I-12.

[5] Lee, Kai N. and Donna L. Klemka with Marion E. Marts. Electric Power and the Future of the Pacific Northwest. Seattle: University of Washington Press, (1980), p. 41.

[6] BPA at 3, p. 44.

[7] BPA at 4, p. II-4.

[8] BPA, A Ten-Year Hydro-Thermal Power Program for the Pacific Northwest. Portland: U.S. Department of the Interior, (1969).

[9] Washington State Senate Energy and Utilities Committee (WSSEUC), WPPSS Inquiry, Vol. I. Olympia, Washington, (January 12, 1981).

[10] Washington State Senate Energy and Utilities Committee (WSSEUC), Energy: Transition to the '80's--Energy Legislation, 1980. Olympia, Washington, (N.D.), p. 20.

[11] WSSEUC at 9, pp. 2-3.

[12] WSSEUC at 9, p. 14.

[13] WSSEUC at 10, p. 22.

[14] Elrick and Lavidge, Inc. Pacific Northwest Residential Energy Survey, Vol. I. Executive Summary. Prepared for the BPA and PNUCC, (August, 1980), pp. 2-3.

[15] Oregon Alternative Energy Development Commission, Future Renewable. Final Report. (September, 1980), p. B-3.

[16] NRDC at 2, p. 24.

CHAPTER 2: CONCEPTS, ISSUES AND ALTERNATIVES IN ELECTRICAL RATE STRUCTURES

As previously noted, the rapidly escalating cost and projected shortfalls of electrical energy in the Pacific Northwest necessitate a re-evaluation of traditional rate structures. This chapter discusses a number of concepts and issues of crucial importance for such a re-evaluation. This discussion provides a framework which is then used in evaluating a number of alternative residential rate structures. The results of this evaluation show that an inverted residential rate structure will best meet the challenges of escalating cost and potential shortfalls facing the region.

2.1 Ratemaking Objectives

Electrical utilities have traditionally been regarded as belonging to the class of what economists call "natural monopolies", and have since their earliest days been subject to government regulation of rates to protect the public interest. The three primary objectives which have traditionally guided the utility ratemaking process have been summarized as: (1) the revenue requirement objective, (2) the fair cost apportionment, or "equity", objective, and (3) the optimum use, or "efficiency", objective.[1] Of these, the revenue objective is paramount. This objective requires rates to be set at a level sufficient to cover costs and, for investor-owned utilities, yield a "fair" rate of return on the utilities' invested capital. Rates should allow a utility to remain financially solvent but prevent it from realizing "excessive" profits. A corollary objective is "revenue stability". That is, the rate structure should not lead to changes in consumption that would lead to large and unpredictable fluctuations in revenue.

The goal of the second criteria, fair cost apportionment, is "equity". That is, rate structures should be set to provide a "fair" distribution of costs. Two somewhat overlapping notions are inherent in traditional definitions of rate equity. The first notion is that rates should be cost-based. That is, the rate that each customer is charged should be directly related to the costs that are imposed on the utility system in providing service to that customer. However, there is growing debate over the question of what definition of "cost" is most appropriate for ratemaking purposes. Traditional utility analysis has held that rates should be related to the "imbedded" or average costs of serving a particular class of consumers. (See Section 2.3 under Flat Rates.) However, it is impossible to calculate the "true" average costs of serving a class of consumers, much less an individual consumer. The measurement of some costs is simply too complex to be practical. Moreover, there is simply no way of allocating some costs associated with overhead and jointly provided services other than in an arbitrary manner.[2] An emerging body of thought among rate analysts and economists holds that rates should be related to marginal costs. This is further discussed below under the efficiency criterion, and in Section 2.3 under Marginal Cost Rates.

A second notion in traditional definitions of equity is that "no customer class should subsidize another". This has been traditionally applied to the relationship of rates between classes (i.e., the residential class should not subsidize the commercial or industrial classes and vice versa). Again, difficulties in defining and allocating costs make the real-world application of this concept somewhat arbitrary.

Finally, the optimum use objective requires rates to promote an efficient allocation of resources. According to economist's formal definition, an efficient allocation of resources is achieved at that level of production where the cost of producing an additional unit of a good (marginal cost) is equal to the revenue that can be obtained from the sale of that good (marginal revenue). In the field of utility regulation, the efficiency criterion traditionally has meant that rates should encourage the most efficient use of utility resources, e.g., promote high load factors, and use of a utility's least expensive resources. In times of excess hydro capacity, declining block rates promoted additional energy use, greater load factors, and lower costs for all customers. That is, given excess capacity, costs per unit of ouput were decreasing, and declining block rates helped approximate an efficient allocation of resources. However, the region's excess hydro capacity has now vanished, and costs per unit of additional output are increasing. Therefore, the efficiency rationale for declining block rates no longer holds. Thus, more recently, the efficiency criterion has been re-interpreted to mean that rates should also be designed to discourage wasteful or excessive consumption.[3] It is not growth in demand per se that is discouraged, but inefficient growth--growth induced from consuming electrical energy at a price less than it costs society to produce.

It is impossible for any one rate structure to completely maximize the three objectives of (1) adequate revenues, (2) efficient allocation of resources, and (3) fair cost apportionment. One reason is that these ratemaking objectives are in partial conflict. For instance, rates which are concerned only with tracking past costs and distributing them in an "equitable" fashion among customers will conflict with the objective that rates encourage optimum use (that is, efficient allocation of resources). Similarly, pure marginal cost pricing would maximize the efficiency objective, but violate the revenue objective by allowing utilities excess profits in times of increasing costs. Further, as noted above, some of these ratemaking objectives are of a very elusive, nebulous character. For instance, if you were to ask an accountant, an economist or an engineer to define "costs" or "fair cost apportionment", you would probably get three different answers.

Under these conditions, the "best" utility rate can only be derived by a series of tradeoffs--hard choices between the revenue objective, the efficiency objective, and the equity objective. A general rule of thumb is that the closer a rate design comes to meeting <u>all three</u> objectives, the closer it approaches an optimum design. In reality, different weights or levels of importance are likely to be attached to the different objectives and their relative priorities are likely to change as conditions change. As the cost of electrical energy rises, and shortfalls become increasingly likely, it is appropriate that the efficiency objective receive greater emphasis.

2.2 The Price Elasticity of Residential Electricity Demand

The concept of "price elasticity of demand" is crucial for an understanding of the potential impact of alternative rate structures on the demand for electrical energy. This section explains the concept of "price elasticity of demand", or price elasticity, and discusses a number of factors of critical importance for interpreting the relationship between price elasticity and rate reform. Finally, this section summarizes the results of empirical research on the price elasticity of residential demand for electric energy.

Price elasticity is a term used by economists to describe and measure the responsiveness of the demand for any good to changes in the price of that good. Mathematically, it is the percentage change in the quantity demanded divided by the percentage change in price: (% Change Quantity)/(% Change Price). The following example shows how elasticity is determined: Suppose that 10 units of good x are demanded at a price of $4.00 each, but only 8 units of good x are demanded if the price of x increases to $5.00. In other words, demand decreases by 20% in response to a 20% increase in price. In this case, the price elasticity of demand is (-20/20) or -1. This means that a one percent increase in the price of good x will cause a one percent decrease in the quantity of x that is demanded. For "non-status" goods, the "law of demand" holds that price elasticity is always a negative value or zero. That is, the quantity of a good demanded will either decrease or remain constant as its price increases, assuming all other factors are unchanged. Demand is termed "inelastic" if elasticity is a value from zero to -1, and "elastic" if elasticity is -1 or greater. However, it should be understood that the terms "inelastic" and "elastic" are arbitrary descriptive terms of much less importance than actual elasticity values themselves.

Both economic theory and research suggest a number of factors that importantly influence the price elasticity of residential electrical energy demand. These include the price of substitute fuels (natural gas and oil), the level of income of consumers, and time. Time is important in two ways. First, given the existing stock of heating and cooling systems and appliances, electrical energy use varies by season and time of day to provide a number of different services (heating, cooking, hot water, lighting). Each of these services may have a different price elasticity at different times. These considerations are important for the analysis of peak load pricing, which will not be considered here.

Time also enters into considerations of elasticity in a second important way: It is the element that distinguishes short-run from long-run responses.

Short-Run vs. Long-Run Elasticity

Any discussion of elasticity must acknowledge the influence of time on patterns of consumer behavior. Consequently, considerations of the price elasticity for electricity should acknowledge the distinction between short-run and the long-run responses. In the short run, customers can respond to a price increase only by reducing the use of their existing capital stock of appliances and heating and cooling equipment. For example, an electric heating customer can turn down his thermostat but is not likely to switch to another primary fuel source or retrofit his house in a day, week, or perhaps even a year in response to an increase in electricity prices. Consequently, the effects of price on consumption are somewhat restrained in the short run.

However, in the long run, changes in usage <u>and</u> capital stock are possible; customers can use less electricity but also change their appliance and equipment mix so that less electricity is needed to accomplish the same tasks. This gives each customer a wider range of responses to an increase in the price of electricity. For example, in the long run, an electric heating customer can respond to an electricity price increase not only by turning down his thermostat, but also by varying his appliance stock, weatherizing his house, installing a heat pump, or switching to another primary and/or supplemental fuel source (wood, gas, etc.). Because of the ability of each consumer to vary both usage and capital stocks, long-run price elasticity generally is much greater than short-run elasticity.

There is no precise definition of short run and long run. However, major changes in the stock of large appliances or heating systems do not seem likely in less than a three to five-year period.

Estimating Elasticity

Estimates of price elasticity are derived by statistical analysis of available data on price and consumption. Properly specified statistical analysis will estimate the short-run and long-run price elasticity of electricity demand while accounting for differences in consumption due to factors like weather, income and family size. Two types of raw information may be used in statistical analysis: (1) time-series data, or (2) cross-sectional data.

Time-series data are observations of a single customer group (e.g., residential consumers or the state) over a period of time (usually several years). A time-series study of the elasticity of demand for electricity might relate changes in kwh consumption of a large group of customers from 1970-1975 to changes in the price of electricity. Time-series studies have the advantage of analyzing actual changes--they represent the demonstrated response over time of customers to price increases. However, given data usually available, they have the disadvantage of only showing year-by-year or strictly short-run responses to electricity price increases. Adjustments can be made which allow for the lagged or long-run response of consumers to electricity price increases but, without considerable data, these adjustments can lower statistical reliability. Another disadvantage of time-series studies is that information on some important factors affecting consumption may be limited or non-existent over the period of years in which a study is done; this may act to bias study results.

By contrast, cross-sectional data are observations of a wide group of customers at one point in time. In this sense, cross-sectional data can well be described as a "snapshot" of consumption as opposed to time-series data which "track" consumption. A cross-sectional study of elasticity might try to relate the consumption of residential customers in 50 states in 1980 to the different prices which they paid for electricity. Cross-sectional studies have the advantage of being able to draw a data base from extensive, intermittant sources of information like census reports. They also can be used to predict long run responses to an increase in energy prices more easily than time-series data. However, cross-sectional studies by their very nature are not as dynamic as time-series studies.

Studies of the Price Elasticity of Demand for Electricity

It seems reasonable to agree with the recent judgment of one observer that the accumulated knowledge regarding the price elasticity of demand for electricity is "pretty good." There is no dearth of studies on the subject and existing studies have been exposed to rigorous review by sources within and outside of the utility industry.

One of the most extensive reviews of research to date has drawn the following general conclusions with regard to the price elasticity of electricity demand.[4]

-- The price elasticity of demand for energy for all customer classes is much larger in the long run than in the short run.

-- Over the long run, the demand for energy for all classes is price elastic.

-- The long-run price elasticity for electricity is roughly -1.0 for the residential class.

-- The short-run price elasticity for electricity varies between -0.15 and -0.30 for the residential class.

These conclusions are based on the results of numerous studies summarized in Table 2-1, and provide a general reference to the effect of price increases on residential consumption. However, these are aggregate figures for the U.S. as a whole, and may not account for a wide variety of factors--weather, socio-economic conditions, and end-use characteristics--which vary significantly from region to region. The use of these figures by any particular utility could misrepresent local values. Consequently, the report stressed that any elasticity values used for decision-making purposes should be derived on a regional or utility-system basis.

Thus, it is important to look at studies that have been conducted on a regional or local basis. The result of some recent studies of the price elasticity for electricity in Washington are summarized below:

Price Elasticity of Electricity -- Residential

Study	Scope	Short Run	Long Run
Mount, Chapman & Tyrrell[5]	Washington	--	-1.04
Energy 1990[6]	City of Seattle		
Single Family-Electric Heat		-0.36	--
Other Residential		-0.43	-0.61
SCL Econometric Model[7]	City of Seattle		
Single Family-Electric Heat		-0.46	-0.46
Other Residential		-0.72	-0.72

TABLE 2-1

PRICE AND INCOME ELASTICITIES FOR ELECTRICITY

Study	Data Type[a]	Data Vintage	Price Elasticity[b] Short-Run	Price Elasticity[b] Long-Run	Income/Output Elasticity[b] Short-Run	Income/Output Elasticity[b] Long-Run	Type[c] of Price
RESIDENTIAL SECTOR							
Houthakker (1951)	CS: U.K. Cities	1937-38	-0.09		1.16		M
Fisher-Kaysen (1962)	CS-TS: USA States	1947-57	-0.15	0.00	0.10	Small	A
Houthakker-Taylor (1970)	TS: USA	1947-64	-0.13	-1.89	0.13	1.94	A
Wilson (1971)	CS: SMSA's	1960, '66		-2.00		0.00	A*
Halvorsen (1972)	CS: USA States	1961	-1.18				M*
Anderson (1972)	TS: Calif.	1947-69	-0.58 ~ -0.77				A*
	CS: USA	1969	-0.84 ~ -0.90				A*
	CS: USA	1969	-0.77				A*
Halvorsen (1973a)	CS-TS: USA	1947-69	-0.26	-2.11			M*
Mount-Chapman-Tyrrell (1973)	CS-TS: USA States	1946-70	-0.14	-1.20	0.02	0.20	A
Anderson (1973)	CS: USA States	1960-70		-1.12		0.80	A*
Lyman (1973)	CS-TS: Area Served by Utility		-0.90		-0.20		A
Houthakker-Verleger-Sheehan (1974)	CS-TS: USA States	1959, 1965, 1970	-0.90	-1.02	0.14	1.64	M
Griffin (1974)	TS: USA	1951-71	-0.06	-0.52	0.06	0.88	A
Baughman-Joskow (1974)	CS: USA States	1969	-0.53 ~ -2.08[d]				A
Asbury (1974)	TS: USA	1959, 1965, 1970	-0.88 ~ -1.14				A
Acton-Mitchell-Mowill (1976)	CS: Small Geographical Areas	1972-74	-0.70				M
	CS-TS: Small Geographical Areas	1972-74	-0.34				M
Wilder-Willenborg (1975)	CS-Individuals	1973		-1.00		0.16	M*
Uri (1975)	TS: Monthly USA		-0.81	-1.66	0.04	0.12	A
Halvorsen (1975)	CS-TS: USA States	1960-70	-1.15	-1.52	0.51	1.62	M*
Lacy-Street (1975a)	TS: Area Served by Alabama Power Co.	1967-75	-0.46		1.87		M
Taylor-Blattenberger-Verleger (1976)	TS: USA States	1956-72	-0.07	-0.78	0.10	1.18	M
Chern (1976a)	CS-TS: USA States	1971, '72	-1.44[e]		0.82[e]		A

TABLE 2-1 Contd.

PRICE AND INCOME ELASTICITIES FOR ELECTRICITY

Study	Data Type[a]	Data Vintage	Price Elasticity[b] Short-Run		Price Elasticity[b] Long-Run	Income/Output Elasticity[b] Short-Run	Income/Output Elasticity[b] Long-Run	Type[c] of Price
RESIDENTIAL SECTOR (continued)								
FEA (1976)	CS-TS: USA Census Regions	1960-72	-0.18		-1.46	0.30	1.10	A
Lin-Hirst-Cohn (1976)	CS: States	1960, '70		-0.30[f] -2.63[g] -2.63[h] -1.05[i]				A
Halvorsen (1976a)	CS: States	1969			-0.97		0.71	M*

a — TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.
b — Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.
c — M refers to marginal price; M* to a theoretical model in which both average and marginal price elasticities are identical (price data was, however, either A or A*); A to an average price for electricity; and A* to an average price for a fixed amount of electricity.
d — These are "saturation" electricities and in general should be smaller than true price elasticities.
e — Combined residential and commercial sectors.
f — Saturation elasticity for food freezing.
g — Saturation elasticity for space heating.
h — Saturation elasticity for water heating.
i — Saturation elasticity for cooking.
j — Value is unity by the assumption.
k — Combined industrial and commercial.

Source: Edmunds, James A. A Guide to Price Elasticities of Demand for Energy: Studies and Methodologies. Oak Ridge: Oak Ridge Associated Universities. (August, 1978), Table 2, pp. 15-17.

Since there is such a wide divergence between long-run elasticity values in these studies, it is useful to consider these in some detail. Mount et al. is a cross-sectional study done in 1973 on aggregated data for the state as a whole. It contains two potential sources of error: First, as one study has noted, elasticity estimates "which are based on statewide experience may not reflect the demand response to be expected in any one utility area".[8] Second, Mount et al. used only the average price of electricity in estimating elasticity and numerous theoretical studies have shown that unless elasticity studies incorporate both the marginal and average price of electricity into their equations, the values for elasticity will be overstated.[9]

The Energy 1990 study was conducted in 1976 using time-series data from the Seattle City Light service area, so it avoided many of the distortions which are caused by aggregating data over a wide and dissimilar area. When the long-run elasticity figure was developed, there was some concern that it could have been understated because of "simplistic" assumptions concerning the distributed lag specifications which were used. (As has been mentioned, time-series studies primarily represent short run effects unless specifically adjusted or "lagged" to account for long run price effects.)

The last set of elasticity values are currently used in Seattle City Light's Econometric Forecasting Model. They have been derived from a time-series study of SCL's service area and are perhaps the best local estimate of elasticity since they represent hard figures grounded in actual utility experience. It is important to note that the estimating procedure used in the forecasting model does not distinguish between short-run and long-run price elasticities. Thus, the figures shown probably overstate short-run and understate long-run elasticities. Further, the price elasticity shown for all-electric customers is less than that for other customers--a result that is counter-intuitive. However, the price elasticity for "other households" is estimated to remain constant as the price of electricity increases, while the price elasticity for "all-electric customers" is estimated to increase with the price of electricity. That is, as electricity prices increase, so will the price-elasticity of all-electric customers. It is interesting to note that the elasticities derived by Seattle City Light are roughly similar to the elasticity figures of the Energy 1990 study.

Elasticity and Level of Demand

A factor which, until recently, has not been of concern in studies of demand for electricity is the relationship between price elasticity and the level of demand. The question here is whether or not elasticity varies as a function of an individual consumer's level of demand: i.e., is the demand of customers with high levels of consumption more or less elastic than the demand of those whose consumption levels are low? Until recently, this question has attracted little empirical study. The intuitive response is that, at least in the residential class, the demand of customers with low levels of consumption is relatively price *in*elastic compared to those with high levels of consumption. The reasoning is this: The loads of residential consumers with low consumption levels are primarily lighting and appliance use. The opportunities for reducing these loads are small. Conversely, those residential customers with high loads are typically space and water heating customers with significant opportunities to reduce load by either changing their source of energy, or by improving the efficiency of energy use--insulating, caulking, etc. This question has important implications for both the equity and efficiency considerations in rate design. There is some evidence to indicate that customers with higher usage levels have higher price elasticities of demand than lower use customers.[10]

Consumer Choice and Electricity

Besides knowing something about the magnitude of the price elasticity for electricity, it is important to discuss several questions about the nature of consumer behavior with regard to electricity: What triggers the consumer to cut consumption in response to an increase in price?

What signals do consumers attend to in making consumption decisions? These questions are concerned, at root, with the issue of whether consumers are influenced more by (a) their marginal price of electricity (i.e., the price they pay for additional levels of consumption), or (b) their average price of electricity reflected in their total electric bill.

For purposes of this discussion, marginal price means the price that a consumer must pay for the next kwh of electricity consumed. For example, suppose that a customer faces a declining block rate under which he is charged 2¢/kwh for the first 500 kwh's and 1¢/kwh for usage above 500 kwh's. If this customer uses less than 500 kwh's, the marginal price of electricity--the price that he must pay for one more kwh--is 2¢. Should he use more than 500 kwh's, the marginal price of electricity will be 1¢. It is important to differentiate between <u>marginal cost</u> and <u>marginal price</u> because these two terms will have a prominent place in a later discussion of rate concepts. Marginal price means the price a customer must pay for the next unit of electricity. Marginal cost is the total cost to the utility of producing one more unit of electricity.

The conclusions that can be drawn regarding the influence of (a) the marginal price, or (b) the total bill on consumption have broad implications for the way that utility rates should be designed. If consumption is determined by the marginal price, then careful attention should be given to both rate structure <u>and</u> the rate level, and rate structures which raise the marginal price of electricity (i.e., inverted rates) will induce conservation. However, if customers only pay attention to their total bill, then the rate structure (declining block, flat, inverted) has less of an impact on consumption. However, even if people only respond to total cost, rate structures can be designed to focus cost increases on those consumers whose demand is most elastic, typically thought of as those with high demands.

The Marginal Price Argument

Economist Lester Taylor has capsulized the "marginal" argument while commenting on the use of marginal versus average prices to determine elasticity for electricity: "The conventional view since Houthakker's earlier work is that a marginal price not an average price should be used in the demand equation, the reasoning being that the consumer, in achieving equilibrium, equates benefits with cost at the margin."[11]

Economic theory regarding consumer choice stresses that an individual will purchase any good until the marginal benefit of the last unit consumed equals the price paid for that unit (i.e., the marginal price). To use the electricity example, if the marginal price of electricity is 2¢ per kilowatt hour (kwh), each customer will use electricity until the value received from the last kilowatt hour (kwh) consumed equals the marginal price of 2¢.

If the marginal price of electricity were to increase to 5¢/kwh, each customer would cut back marginal consumption until the value received from the last kwh consumed would equal 5¢; former uses of electricity which were valued at less than 5¢/kwh would be eliminated.

The Total Bill Argument

The opposing side of the argument states that consumers make choices about electricity consumption on the basis of the average price of electricity--the total electric bill. The "total bill" argument was expressed by witness Swartzell (Puget Power) in the Utilities and Transportation Commission's generic rate hearings:

> "...our residential and smaller non-residential customers generally respond in a somewhat unsophisticated way to the world around them. I believe that customers are much more aware of the amount of their bill than the form of the rate they are charged."[12]

It is argued that consumers respond in an "unsophisticated way" to their utility bills for a couple of reasons: First, since electricity still comprises a small and insignificant portion of each customers total budget and since electricity prices in the Northwest have historically been so low, people simply do not pay attention to utility bills. Second, customers do not know--and are not interested in knowing--what the marginal price of electricity is. (As of this writing, no utility in the state prints its rate structure on customer bills.)

Existing Evidence

Existing empirical evidence tends to cautiously support the notion that a customer's marginal price--not the average price or total electric bill--is what determines electricity consumption. This has been tested as follows: In the past, most electricity customers were charged a declining block rate; that is, a rate which the charge per kwh decreased as electrical consumption increased. This rate (and all other rates) incorporate three types of charges: (1) a fixed charge which was paid regardless of consumption, typically called a customer or service charge; (2) a set of intramarginal charges or charges for electricity which was consumed up until the last block of electricity used; and (3) the marginal price--the price of electricity in the block where each customer's last kwh was consumed.

Recent econometric techniques have made it possible to compare elasticity for the marginal price of electricity with elasticity for the lump sum and intramarginal prices. If the total electric bill determines consumption, then the fixed charge and intramarginal charges should be statistically as important than the marginal price in influencing consumption.

A 1976 Rand study of the residential demand for electricity in Los Angeles determined that "the lump sum components of the declining block rate structure (customer charge and amount of payment above marginal price in preceding blocks) have a negligible effect on the amount of electricity consumed." Further, the study found that there was zero elasticity with regard to the fixed charge components of a customer's bill. That is, an increase in the customer charge would not influence consumption. One of the authors has concluded that these results "show that the marginal price is the driving force behind consumption."[13]

Another study done for the Electric Power Research Institute focused on the national residential demand for electricity from 1956-1972.[14] It termed the marginal price of electricity "highly significant statistically" in consumption decisions. Furthermore, it found the fixed charge component of customer bills "not nearly as important statistically as income or marginal price" in determining electrical consumption. It is interesting to note that this study was recently submitted in the UTC generic rate hearings by Dr. Frederick Wells, witness for P.O.W.E.R. (People Organized for Washington Energy Resources), as "strong empirical evidence that the marginal kwh electric rate is the factor which controls customers' decisions about energy use." Although the validity of that assertion was questioned by a utility witness, staff witness Gibson stated, "I would have to agree with Dr. Wells that <u>the bulk of the evidence indicates that the long run elasticities for marginal prices are significantly larger (in absolute magnitude) than the elasticities for what the authors characterized as 'fixed charges'</u>, that is, the combined effect of customer charges and intramarginal prices. This is what economic theory would lead us to expect...."[15] (Emphasis added.)

Finally, the Seattle City Light <u>Energy 1990</u> study found that electrical energy demand was considerably more responsive to marginal price than to average price. Thus, the marginal price elasticity of residential demand was estimated to be from -0.90 to -1.0, while the long-run average price elasticity was estimated as -0.61.[16]

2.3 Rate Design Alternatives for Washington

This section will discuss six alternative rate designs and evaluate them in light of the three ratemaking objectives (efficiency, adequate revenues, fair cost apportionment) discussed in the previous section. The alternatives will include:

- Declining Block Rates
- Flat Rates
- Marginal Cost Rates
- Baseline Inverted Rates
- Lifeline Rates
- Seasonal Rates
- Time-of-Day Rates

1. <u>Declining Block Rates</u>

A declining block rate prices successive blocks of kwh usage at lower per-unit prices. A typical declining block rate structure appears as follows:

Fixed charge	$5.50
Energy charge	
First 1500	2.2¢ per kwh
Over 1500	1.8¢ per kwh

(Source: Kittatas Co. PUD)

Declining block rates rose out of declining cost conditions which prevailed for the region's utilities until the 1970's. During this period, the costs of producing and distributing energy declined substantially due to the presence of significant economies of scale and improvements in technology. Consequently, the more energy that was produced, the less the per unit cost.

In this environment, declining block rates were "efficient". They were cost-based because, given excess capacity in a hydro-based system, an increase in consumption by each customer did result in a less than proportionate increase in the cost of service. Further, declining block rates met optimum use or efficiency criteria by providing consumers the correct signal about the cost of additional supply. In this sense, declining block rates arose in part out of marginal cost principles. For example, witness Swartzell (Puget Power) commented on this in the recent UTC generic rates hearing:

> "I think we have always recognized marginal costs in our rates, at least implicitly. Certainly, in the days when marginal costs were lower than historical costs, we signalled customers by the use of promotional rates for residential water heating and certain commercial uses."[17]

The conditions which once justified declining block rates simply no longer exist. Utilities now face increasing cost conditions: The cost of additional plant capacity is much higher than the cost of existing capacity. This is especially true in Washington where the potential for additional low-cost hydro resources has been largely exhausted and most incremental plant capacity will have to come from high-priced thermal plants. In 1979, the average cost of BPA hydro power (which is the main power source for most of the state's PUDs) was 0.4¢/kwh; while the long-run incremental cost of power--the cost of power from the scheduled WPPSS plant additions--can be estimated at about 4.5-5.5¢/kwh.[18] In other words, new power supplies are over ten times more expensive than old power. Under these conditions, there is no cost justification for declining block rates because system costs will not decrease as consumption increases.

On equity grounds, the declining block rate was justified in the past because it promoted consumption which in turn improved the utilities' system load factor; that is, it improved the ratio of average to peak load. An improved load factor resulted in lower system costs which could justifiably be passed on to large consumers. However, this reasoning is no longer appropriate. Utilities in Washington have been running very near capacity and possess extremely high load factors already. Furthermore it appears that load factors do not necessarily increase as consumption increases. Thus, large residential customers (who use electricity for space heating) can be expected to worsen the annual load factor because their heating demands add to the system peak in the winter.

In an environment where new resources are more expensive than existing resources, declining block rates also violate the fair cost apportionment objective by forcing stable customers to subsidize growing or inefficient customers. This is inequitable because the rates charged in the high consumption block are below the cost of service. Yet greater inequity occurs because declining block rates encourage some customers to increase consumption with the result that the utility must add additional expensive plant capacity and raise rates for all customers.

The strongest argument against declining block rates is that they violate the optimum use, or efficiency, criterion in ratemaking. In a time when the marginal costs of electricity are going up, a declining block rate tells a customer that costs are going down. The outcome is that declining block rates promote wasteful or inefficient consumption; that is, electricity usage which is valued below what it costs society to produce.

In a time of increasing costs, a declining block rate can seriously hinder the ability of a utility to meet its revenue requirement because it promotes consumption that involves expensive marginal costs which the utility cannot completely recover. As a result, the utility must either constantly adjust rates upward or undergo earnings erosion.

2. Flat Rates

A flat electric rate structure is a rate which charges a constant unit price for electricity consumption. The following is an example of a flat rate:

No fixed charge
All energy 1.17¢ per kwh

(Source: Cowlitz Co. PUD)

Flat rates have traditionally been average cost-based rates. They "meld" or average all power costs together and price electricity on an average cost per unit basis.

It is a fairly straightforward process to set the level of flat rates so that the revenue requirement is met.

In times of increasing costs, flat rates can be said to be more efficient than declining block rates, since they more closely reflect the marginal cost of electricity at higher levels of consumption. However, flat rates are not truly efficient because they do not reflect the cost of new resources--they do not provide a signal to consumers that cost will increase as consumption increases.

Flat rates distort and prevent allocative efficiency by melding or averaging historic costs together. From the standpoint of efficiency, future costs, not historic costs, are the most relevant. A consumer considering whether to put in electric water heating or electric space or whether or not to insulate should be concerned not only with what electricity costs are today, but what they will be in five or ten year after the decision is made. Flat rates which average high and low cost power reflect a past in which costs were decreasing, and in no way communicate to the consumer that in the future rate levels will rapidly increase as high cost resources are used to supply additional demand. This causes consumers to make inefficient choices--choices which would not have been made if rates reflected the increasing cost conditions of the future.

3. Marginal Cost Rates

Marginal cost may be defined as the cost of the scarce resources that are necessary to produce one more unit of any good. In the electric utility industry, marginal cost is directly associated with the next new block of plant capacity that is needed to supply demand. (This is also sometimes referred to as long-run incremental cost.) In Washington, the current marginal or long-run incremental cost of power is the cost of power from the WPPSS plants. A marginal cost rate structure would charge approximately 5¢/kwh (the cost of power from the WPPSS plants, plus the costs of transmission, distribution and administration; see footnote 18) as opposed to the 1¢ or 2¢/kwh rates charged currently.

The most compelling argument for marginal cost pricing is that it will indisputably fulfill ratemaking efficiency or optimum use requirements. To quote a witness at the recent UTC generic rate hearings, "There is no real argument about whether marginal cost pricing is right or wrong. If our goal is economic efficiency, it is almost definitional that the prices of commodities must reflect the marginal cost of supplying these commodities."[19]

The efficiency rationale for marginal cost pricing is as follows: In a free economy, consumers are allowed to make voluntary decisions on how much of each good to consume using prices as a guide. If prices do not equal marginal cost, they will guide consumers in a misleading way. When the price of any good is set below marginal cost, consumers will find it cheaper to consume additional quantities than it actually costs society to produce. This will lead to a wasteful and inefficient allocation of resources. Electricity is a prime example of this. In Washington, the marginal cost of electricity is about 5¢/kwh. However, electricity is generally priced near its average cost, which is approximately 1.8¢/kwh. This means that consumers are paying 1.8¢ for consumption that costs society 5¢ to replace. Economist Sally Hunt Streiter pointed out the implications of average cost pricing for Washington State.

> "According to the Washington Water Power Annual Report, 94 percent of new heating customers chose electric heating over gas. This, the company remarks 'is obviously due to misconceptions about supply and price'. But the misconception is not the customer's fault. He doesn't know that the company has to build Centralia or Colstrip or Skagit to meet his demands....
>
> The state of Washington so long blessed with hydro power is now at a point where its marginal costs of electricity are much higher than its historic costs, more so than anywhere else in the country, and unless recognition is made of this in setting electricity prices, the state will find itself in serious trouble."[20]

An argument can be made that setting residential rates at marginal costs would be equitable because (a) they are cost-based, and (b) there would be no subsidization among different residential customers because no group would pay less than the actual marginal cost of service.

A counter argument can be made that rates set at marginal costs are not equitable because they treat all customers the same, when in reality residential customers contribute differently to a system's marginal costs. This view of equity is based on the notion that those who cause increased demand (new customers, or old customers that increase their consumption) should pay the increased costs. Thus, a marginal cost rate will charge a new winter space heating customer a rate which equals "the actual cost of the service", but an electrical customer who has maintained steady or decreasing consumption for 10 years is held just as responsible for growth--and pays the same price per kwh--as the new customer.

Also, a direct move to marginal rates would cause abrupt and disruptive increases in the rates of all residential customers. This could be viewed as unfair because it violates a "good faith" notion of fairness by penalizing customers for appliance and fuel choices that were made in the past under a completely different set of cost assumptions.

The primary problem with marginal cost rates is that they violate the adequate revenue objective of ratemaking. During times of decreasing costs, marginal costs are, by definition, less than average costs, and marginal cost rates would not allow a utility to fully recover costs. During times of increasing costs, marginal costs will exceed average costs, so rates which are based on marginal cost will yield revenues greater than needed to meet the revenue requirement. However, there are ways that marginal cost rates could be adjusted to conform with the revenue objective. One solution would be for the state to impose a tax on the excess revenues and to use these funds to eliminate other existing taxes. This would return the revenue surplus to taxpayers in a way that would not stimulate electricity consumption. Of course, there would still be considerable resistance to this proposal on equity grounds. It could be argued that this proposal would result in large electrical energy users subsidizing large taxpayers.

The practical and administrative problems that exist with pure marginal cost pricing may prevent the revenue objective from being met. However, this should not preclude attempts to recognize marginal cost principles in rates. In times of rapidly escalating cost and inadequate supplies, efficiency is an important ratemaking objective. If marginal cost considerations are neglected in ratemaking decisions, the cost, in terms of inefficient use of scarce resources, will be high.

4. Baseline Inverted Rates

With an inverted or increasing block rate, the unit price of electricity increases as consumption increases. The following is an example of a baseline inverted rate:

Minimum bill	$1.50
First 480 kwh	.86¢/kwh
Additional kwh	2.30¢/kwh

(Source: Seattle City Light)

A baseline rate is a specific form of inverted rate which devotes the benefits of low cost resources (i.e., hydro power) to an initial "essential needs" block and recovers costs needed for more expensive resources in the price charged for consumption of electricity which exceeds that block. Lifeline rates also include an "essential needs" block of energy but at a price which may not necessarily relate to any reasonable measure of costs. Lifeline rates will be treated in a separate section as they differ significantly in purpose and structure from inverted rates.

The baseline inverted rate structure is peculiarly adapted to the Northwest where there is a large base of inexpensive hydroelectric energy, the benefits of which are being diluted by the addition of increasing amounts of expensive thermally-generated energy. The logic behind the baseline rate is this: by reserving a baseline quantity of energy for sale to residential consumers at a rate which is based on the low cost of the existing hydro power resource, the cost of new, expensive resources will have to be recovered in higher rates charged for consumption above the baseline. The effect is an inverted rate structure. These rates will then more closely approximate the marginal cost of new energy, thereby promoting economic efficiency.

If current marginal costs are greater than historic average costs, and marginal cost pricing is not feasible due to the revenue requirement, then optimum use can be more closely approximated by a properly designed inverted rate structure. In the Northwest, efficiency or optimum use arguments for inverted rates exist on the basis of price signals, the inverse elasticity rule, and economic considerations regarding the price of natural gas.

An inverted rate recognizes marginal cost principles by sending customers a proper price signal at higher levels of consumption. Specifically, it tells them that cost increases as consumption increases. Part of the problem with existing declining block or flat rate structures is that they send the wrong price signals for efficient resource use. Declining block rates, which tell a customer that costs decrease as consumption increases, are only appropriate when current marginal costs are below historic average costs. Flat rates, which signal customers that costs remain constant as consumption increases, are only appropriate from an efficiency perspective when marginal costs are equal to historic average costs.

Inverted rates are also supported by the inverse elasticity rule, which holds that in order to meet the revenue requirement, rates should be adjusted so that the percentage departure from marginal cost is inversely related to the elasticity of demand.[21] Put another way, the more elastic demand is, the closer its price should be to marginal cost. This, of course, assumes that high demand is more elastic than low demand, an assumption based on common sense and some empirical evidence.[22]

In Washington, elasticity of fuel and heating equipment choice is likely greater than the elasticity for other electricity use. That is, the new customer who must choose between electric and gas heating or electric resistance heating and a heat pump is much more price-elastic than the average residential customer (who has already made that choice). In this situation, it is efficient to move the price of electricity for space heating closer to marginal cost than the price of electricity for appliance needs. Moving the price of electricity for space heating closer to marginal cost also makes conservation more cost-effective. The potential for such conservation is considerable.

Utilities have, in fact, applied the inverse elasticity rule in this manner in the past. The following excerpt from a consultant's report for the Electric Utility Rate Design Study describes inverse elasticity pricing during a period of decreasing costs.

> "However, it was noted that where economies of scale and technical progress were reducing marginal costs, it would be feasible and economically efficient to offer service at marginal cost for those customers with very elastic use. In electricity, this was especially relevant for uses which were in direct competition with other fuels. It was essentially the policy which had been followed when the electric industry was vying for industrial consumers whose alternative was self-generation.... Electric heating rates based on (lower than average) marginal cost were supported because electric heat was assumed to be elastic compared with basic lighting use."[23]

In today's increasing cost environment, the inverse elasticity rule suggests that the end blocks of a rate structure (in which most space heating use falls) be priced higher than the beginning block (which is made up mainly of relatively inelastic lighting and appliance needs).

Comparisons with the price of natural gas also support the notion that inverted rates will lead to more efficient fuel use decisions. In Washington, natural gas, which is priced comparatively close to the margin costs approximately 2.13¢/kwh (taking into account conversion efficiency).[24] Although the price varies throughout the state, electricity for heating purposes is priced at approximately 1.0-2.0¢/kwh, while the marginal cost of electricity averages about 5¢/kwh and can reach about 8.5¢/kwh during the winter (using combustion turbines to meet peak demand). This is inefficient because customers are choosing between gas and electric heating using electric prices which represent only a fraction of marginal cost. This situation illustrates how an inverted electrical rate structure would encourage efficient fuel choices by pricing the tail block (the block in which space heating falls) at, or close to, marginal cost.

To meet the fair cost apportionment or equity objective of ratemaking a rate must do two things. First, it must be cost-based. Second, it must be structured so that no group of customers is subsidized by another group of customers. The baseline inverted rate meets both of these criteria. When energy supplies come initially from low cost hydro sources, and then from higher cost thermal sources, an inverted rate structure reflects this cost differential and can therefore be said to be cost-based.

With regard to the second criterion, a baseline inverted rate structure can be said to be equitable in the sense that customers with growing electricity demand over the baseline block are not being subsidized by customers with stable or declining demand. In order to satisfy the revenue requirement, inverted rates must be structured so that the vast majority of customers consume more than base block levels. Conversely, an inverted rate structure may be said to be equitable because customers that take actions to reduce energy consumption will realize savings in their electricity bills based more nearly on the actual cost of the energy saved.

Since inverted rates pass through low cost power at a low price, they avoid, or at least minimize, the revenue surplus problem of marginal cost rates. One argument against inverted rates is that they could lead to revenue instability by provoking a drastic customer response, or by making consumption and revenues extremely sensitive to the weather. At worst, it is contended that inverted rates could confront a utility with large blocks of excess power which are not needed due to conservation. On the other hand, existing estimates of price elasticity can give a rough idea of the demand response that could result (see Chapter 4). The experience of utilities in this state with inverted rates (although they have not been steeply inverted) is that they will allow utilities to recover adequate revenues. However, it is possible that some short-term rate adjustments may be necessary after inverted rates are implemented. Finally, if any utilities should happen to have supplies of surplus power as a result of inverted rates it does not appear that this would result in a revenue erosion because surplus power could likely find a ready market from either other utilities in the Northwest or from utilities in the Southwest.

The discussion to this point has ignored some potential problems with the baseline inverted rate structure. These are primarily administrative and political in nature and revolve around the problem of defining the baseline block of electrical energy. In other words, how should "essential needs" be defined? Should different baselines be established for different types of residential users (e.g., heating customers versus non-heating customers, single-family structures versus multi-family, existing heating customers versus new heating customers)? Should factors such as household size be taken into account, and so on? There are arguments to be made on all sides of these issues, generally involving trade-offs between administrative complexity and providing benefits for particular subsets of the residential class. As will be seen in Chapter 4, it is possible to define a (non-zero) essential needs level below which very few consumers fall. The problems involved here are difficult but not unsolvable.

5. Lifeline Rates

A lifeline rate provides low volumes of electric energy sufficient for "minimum needs" at a price which may be below any reasonable measure of the costs of providing that service. A lifeline rate differs fundamentally from an inverted/baseline rate in two respects: (1) a lifeline rate may not be cost-based while inverted or baseline rates are, (2) a goal of a lifeline rate may be to provide rate assistance to low-income customers while the primary goal of an inverted or baseline rate is to encourage the efficient allocation of resources. Indeed, lifeline rates are sometimes restricted to low income customers. The following is an example of a lifeline rate offered by a utility with high generation costs:

Customer charge	
0-240 kwh	2¢/kwh (this block is supplied below cost)
240-480 kwh	3.5¢/kwh
Over 480 kwh	8.8¢/kwh

(Source: Pacific Gas & Electric, California)

Lifeline rates finance the lifeline discount by charging higher prices for consumption above the lifeline block, so they allow the utility adequate revenues and thus satisfy ratemaking revenue objectives. In some applications, notably California, the rates of other customer classes have been revised to make up the revenues lost by the residential lifeline.

In a period of increasing costs, the optimum use objective dictates rates that equal marginal costs; if that is not possible, inverted rates provide the next best option because they raise prices at the margin of most customers' consumption levels to approximate marginal cost. In this context, a lifeline rate could be structured to meet efficiency objectives, and the extent to which a lifeline rate structure meets efficiency objectives would depend on the size and prices of the various blocks of electricity.

Certain types of lifeline rates are supported by the inverse elasticity rule. If the demand for electricity by customers that consume less than the lifeline amount is less price elastic than non-lifeline customers, and if the level of demand of most customers falls in the block priced at marginal cost, then such lifeline rates can be defended on efficiency grounds.

In 1975, Los Angeles instituted a lifeline rate which gave low income senior citizens a 50% discount on a beginning "basic needs" block of 360 kwh's. This discount was made up by a general increase in rates charged to all other residential customers. In 1979, a RAND study found that the lifeline rate produced a net decrease in electricity consumption because the low income senior citizens had a less elastic demand for electricity than other customers. In other words, the price increase faced by non-lifeline customers decreased their consumption enough to more than offset the slight increase in consumption by senior citizen lifeline customers. Thus, one result of the lifeline rate structure was an improvement in allocative efficiency for Los Angeles as a whole.[25]

In 1978, a lifeline discount rate was established for low income elderly in North Carolina. This rate was established expressly for efficiency reasons: Since the elderly poor were determined to be among the most inelastic users of energy, a lifeline rate would promote efficiency among customers with more elastic demand. To quote commission chairman Robert Koger, "It allows the North Carolina commission to move slightly towards marginal cost pricing in the residential sector without giving Duke (Power Company) a windfall profit."[26]

The argument that lifeline rates meet ratemaking equity objectives generally focuses on one of two standards of fairness. Lifeline rates may be judged to be equitable on the basis of a "good faith" standard of fairness (it is unfair to penalize customers for usage patterns which are based on past low rates) or on the basis of an "ability-to-pay" standard of fairness (utility rates, like taxes, should be based on a person's ability to pay). Neither of these standards has been part of traditional ratemaking notions of equity. Rather, utility rates have traditionally been called equitable when each customer is charged an amount equal to the cost of providing service to that customer. Thus, lifeline rates do not meet the traditional equity standard of ratemaking unless there are, in fact, lower costs which are incurred in serving lifeline customers.

6. Seasonal Rates

Seasonal rates are based on the concept of time-differentiated pricing; that is, they recognize variations in costs during different time periods. The following is an example of a seasonal rate:

Minimum charge	$4.00
Summer rate (April-August)	1.6¢/kwh
Winter rate (September-May)	1.84¢/kwh

(Source: City of Ellensburg)

In the Northwest, the greatest demand for electricity occurs during the winter due to the climate and the widespread use of electricity for heating purposes. In contrast, the output of the region's hydro system peaks in the spring and early summer due to the spring runoff and snow melt. This has implications for the cost of electricity. In the short run, a utility meets its winter peak by purchasing power from outside the region or running its least efficient plants. In the long run, a utility must add additional thermal and transmission facilities to meet the winter peak. As a result, electricity consumption is significantly more costly in the winter than it is in the summer.

Equity arguments regarding a seasonal rate take the following form: First, seasonal rates are cost-justified given the higher costs of service during the winter. Second, seasonal rates will prevent summer peaking customers from subsidizing winter peaking customers by charging winter customers a rate which reflects higher costs of service in the winter.

Seasonal rates have two implications concerning efficiency. First, they move towards marginal cost pricing by "signalling" the customer that additional consumption is more expensive in the winter than it is in the summer. Second, seasonal rates, in effect, increase the price of electric space heating and move space heating rates closer to marginal costs. Since space heating use occurs mainly in the winter, such a move would encourage efficiency in fuel choice and would be supported by the inverse elasticity rule.

Seasonal rates may also be supported on the grounds that they enable a utility to meet its revenue requirements, especially during the winter months. Bonneville Power Administration currently has seasonal rates: the power it sells to utilities costs 10% more in the winter than it does in the summer. Few utilities in the state "pass through" this difference to consumers and the BPA has pointed out that if utilities average the 10% winter surcharge into their residential rates they may experience cash shortages during the winter months when BPA rates are higher and cash surpluses in the summer months when BPA rates are lower.[27] While this has not been a serious problem to date, it could become more acute in the future if BPA increases the summer-winter differential.

Although seasonal rates have an important and useful role to play, they do not represent a complete substitute for a year-round marginal cost rate structure in the Pacific Northwest. Given the storage capacity and low peaking costs of the region's hydro system, electrical consumption during the off-peak season uses energy that could, at least in part, be available for peak season consumption. In technical terms, the constraint facing the region's system is not so much capacity as total energy.

7. Time-of-Day Rates

Time-of-day rates are a form of marginal cost pricing designed to improve a utility's load factor (i.e., to improve the ratio of peak to off-peak demand). Time-of-day rates price energy higher at certain times of the day when demand is greatest--this cuts down the need for expensive peaking facilities and lowers utility costs. Time-of-day rates have been a widely accepted rate innovation in many other parts of the country, but, briefly stated, they have less relevance for Washington's hydro-based utilities which are impacted more by marginal thermal costs than they are by peak costs.

There are few peaking costs associated with hydro power, and utility costs are currently increasing primarily because of the need of more expensive thermal power, and not from a poor load factor. If Washington's utilities should ever reach the point where peak to base fluctuations exceed the capability of the hydro system, then time-of-day rates may have some relevance. Until that time, there are greater benefits from rates which reduce overall consumption (and the need for thermal power) rather than rates which shift consumption from one part of the day to another but do not reduce overall consumption.

FOOTNOTES TO CHAPTER 2

[1] Bonbright, James. Principles of Public Utility Rates. New York: Columbia University Press, (1961), pp. 291-294.

[2] Ibid, pp. 294-301.

[3] Sacarto, Douglas M. Electricity Pricing and Demand. Denver: National Conference of State Legislatures (1978), p. 2. National Association of Regulatory Utility Commissioners (NARUC), Electric Utility Rate Design Study: Rate Design and Load Control (1977), pp. 32-39. Electric Power Research Institute (EPRI), Rate Design And Load Control: Issues & Directions. Electric Utility Rate Design Study. Palo Alto, (November, 1977).

[4] J.W. Wilson & Associates. Elasticity of Demand prepared for the Electric Utility Rate Design Study. (February 10, 1977), pp. 34-49.

[5] Mount, T.D., L.D. Chapman and T.J. Tyrrell. "Electricity Demand in the United States: An Econometric Analysis". Oak Ridge: Oak Ridge National Laboratory, ORNL-NSF-EP-49, (May, 1973).

[6] Mathematical Sciences Northwest, Inc. (MSNW). Energy 1990 Consultants Report--Vol. III, Loads and Resources Forecast, prepared for Seattle City Light: (February, 1976), p. 3.31.

[7] Seattle City Light, Power Management Division, A Forecast of Electrical Load for the Seattle Service Area for Years 1980 Through 2000. (March, 1980), pp. 38-39.

[8] J.W. Wilson and Associates at 4, p. 25.

[9] See Acton, Mitchell & Mowill; Residential Demand for Electricity in Los Angeles, Rand Corp., (1976); and Lester Taylor; "The Demand for Electricity: A Survey", Bell Journal of Economics, (Spring 1975).

[10] Pacific Gas and Electric Company, Energy Cost Adjustment: Status of Residential Elasticity Studies, submitted to the California PUC in response to Decision No. 91335, Application No. 60007, (N.D.).

[11] Taylor, Lester at 9, p. 78.

[12] Swartzell, Richard. Testimony before the Washington Utilities and Transportation Commission; Generic Rates Hearing; Cause U-78-05, p. 7.

[13] Acton, Mitchell & Mowill at 3, p. 51. Also, telephone conversation with Jan Acton (July 7, 1980).

[14] Taylor, L.D., G.R. Blattenarger, and P.K. Verleger. The Residential Demand for Energy. Lexington, Mass.: Data Resources, Inc. Prepared for the Electrical Power Research Institution. (January, 1977)

[15] Gibson, Wallace. Rebuttal testimony before Washington Utilities and Transportation Commission; Cause No. U-78-05. (October, 1979)

[16] MSNW at 6, p. 3.31.

[17] Swartzell at 12, p. 9.

[18] Calculated from estimated annualized costs of 45.6 mills/kwh in 1983 (current dollars) from WNP-2 as reported in Washington Public Power Supply System (WPPSS), WNP-2 Bond Statement (November, 1980). Assumed annual inflation rate from 1981 to 1983 of 10%/year, and transmission losses of 10%. The range is based on plant factors of 55% and 70%.

[19] Streiter, Sally Hunt. Testimony before Washington Utilities and Transportation Commission; Cause U-78-05. (April, 1979), p. 5.

[20] Streiter, Sally Hunt. Rebuttal testimony before Washington Utilities and Transportation Commission; Cause U-78-05, pp. 2-4.

[21] Levy, Yvonne. "Pricing Federal Power in the Pacific Northwest: An Efficiency Approach", Federal Reserve Bank of San Francisco Economic Review, (Winter 1980), pp. 3-26.

[22] Pacific Gas and Electric at 10, p. 21.

[23] National Economic Research Associates (NERA), Ratemaking, prepared for the Electric Utility Rate Design Study. (June 6, 1977), p. 49.

[24] This cost estimate is based on price of 45¢/therm and a conversion efficiency of 0.7.

[25] Sullivan, Timothy. The Los Angeles Senior Citizen Lifeline Electricity Rate. Santa Monica: Rand Corp., (January, 1979).

[26] Koger, Robert. "Is There Economic Justification for a Lifeline Rate?"; Public Utilities Fortnightly. (May 10, 1979), p. 17.

[27] Bonneville Power Administration (BPA), Draft Role Environmental Impact Statement, Appendix C, Power Marketing. (July 22, 1977), p. IV-235.

CHAPTER 3: TRENDS IN RATE STRUCTURES

This chapter provides a brief summary of existing electrical rate structures in the state, then discusses in greater detail the trend toward inverted electricity rate structures in Washington and ther states.

3.1 Overview of Rate Structures in Washington

The results of a recent committee survey of the status of utility rate structures in Washington are presented in Tables 3-1 and 3-2. These data reflect the rate structure existing in the spring of 1980. The results of the survey may be summarized as follows:

1. Flat rates are the most common residential rate structure in the state. Thirty-six utilities, or 63%, of the state's utilities employ flat rates.

2. Nine utilities in the state still employ declining block rates. This figure is understated, however, because many utilities have flat energy rates but high fixed charges; this makes the rates flat in name but not in effect.

3. Eleven utilities, or 20%, of the state's utilities employ inverted residential rates.

4. Two utilities, Ellensburg and Seattle City Light, have incorporated seasonal features into their residential rate structures.

3.2 The Trend Toward Inverted Rates

There has been a recent trend toward inverted rates, especially among hydro constrained utilities* in Washington and elsewhere. This section

*A hydro-constrained utility may be defined as a utility which relies heavily on hydroelectric facilities for its power supply, but is unable to expand hydro facilities significantly.

TABLE 3-1

RATE STRUCTURES OF UTILITIES IN WASHINGTON

Residential

Type of Structure	Utilities
Declining block rates	Eatonville and Fircrest Municipals; Kittitas County PUD, Pend Oreille County PUD, Skamania County PUD; Inland Power & Light, Lincoln Electric Coop, Orcas Power & Light.
Flat rates	Ruston, Centralia, Coulee Dam, McCleary, Milton, Tacoma, Richland, Steilacoom and Waterville Municipals; Benton County PUD, Clallam County PUD, Cowlitz County PUD, Klickitat County PUD, Douglas County PUD, Ferry County PUD, Franklin County PUD, Grant County PUD, Mason County PUD #1, Mason County PUD #3, Okanogan County PUD, Pacific County PUD, Snohomish County PUD, Wahkiakum County PUD; Alder Mutual, Benton REA, Columbia REA, Big Bend REA, Elmhurst Mutual, Lakeview Light & Power, Ohop Mutual, Nespelem Valley Coop, Okanogan County Coop, Parkland Light & Water, Tanner Electric; Pacific Light & Power, Peninsula Light & Power.
Declining block except for last block	Grays Harbor County PUD.
Increasing block	Cashmere, Blaine, Cheney, Port Angeles and Seattle Municipals; Chelan County PUD, Clark County PUD, Lewis County PUD; Modern Electric Light Company; Puget Sound Power & Light, Washington Water Power.

TABLE 3-2

UTILITY RATE STRUCTURES IN WASHINGTON

Residential

	Municipals	Mutuals-Coops	PUDs	Investor-Owned (Private)	Total
eclining lock	2	4	3	-	9 (16%)
lat rates	9	12	14	1	36 (63%)
eclining lock except ast block	-	-	1	-	1 (2%)
nverted rates	5	1	3	2	11 (20%)
					57 (100%)

will describe inverted rate structures that have been adopted by some utilities and present the reasoning behind the adoption of inverted rates. This section first examines actions taken by three Washington State utilities: Puget Power; Washington Water Power; and Seattle City Light. Then it will examine some other states which have moved toward inverted rates.

Seattle City Light

Since 1974, Seattle City Light has had a three block inverted rate structure for most residential customers. In a recent ratemaking position paper, City Light affirmed its support of inverted rates for residential customers because (1) inverted rates are cost-based when electricity comes first from "low-cost hydro resources" and then from "higher cost resources", and (2) inverted rates send the proper price signal to customers.[1]

Last summer, the Seattle City Council removed the fixed charge for electricity, instituted seasonal rates, and inverted the rate structure even more steeply. The new winter rate appears as follows:

Minimum bill	$1.50
No monthly service charge	
First 480 kwh	.86¢/kwh
Additional kwh	2.30¢/kwh

There are two interesting features about this rate that deserve attention. First, although average costs were used to determine the revenue requirement, the City Council attempted to incorporate marginal cost principles as much as possible in the rate structure. There are a number of different ways to design cost-based rates. City Light used a Marginal Cost of Service Study; that is, a study which determined "the time differentiated marginal cost of supplying energy to City Light customers."[2] This is an important decision because it shows that the state's largest consumer-owned utility has decided that marginal costs (the costs of supplying future electricity) as well as average costs (the historic costs of supplying electricity) are relevant to the ratemaking process.

The second interesting feature of Seattle's new residential rate is that the inverse elasticity rule was used to move the rates towards marginal cost pricing. This meant that Seattle tried to price elastic uses of electricity as close as possible to marginal costs, and inelastic uses were allowed to deviate from marginal costs in order to meet the revenue requirement. For instance, the rate charged for space heating (which generally occurs in the winter in usage above 480 kwh per month) was priced closer to the marginal cost of supplying electricity during the winter because the demand for space heating is much more elastic than other residential demands. The resulting price of electricity for space heating during the winter (2.3¢/kwh) has moved much closer to the equivalent price of natural gas heating (2.76¢/kwh). This will give customers who are making a decision between gas and electric heating--or customers contemplating a conversion to electric heating-the correct price signal on what it costs to supply their demand, and should result in improved efficiency among space heating customers.

Once the price of electricity during the winter was set at marginal cost, the monthly fixed charge was dropped and the summer rates were adjusted to allow the revenue requirement to be met. The reason that the monthly fixed charge was dropped was that demand with regard to the fixed charge is highly inelastic. Obviously a customer would not forego electric service unless the fixed charge was set at a very high level. Consequently, efficient resource use was promoted by removing the fixed charge and allowing the rates charged in the higher, more price elastic blocks, to approach marginal costs.

Washington State Utilities and Transportation Commission (UTC)

As required by the Public Utilities Regulatory Policies Act (PURPA) of 1978 (P.L. 95-617, 16 U.S.C.A. 2601, et. seq.), the UTC undertook in 1978 a comprehensive review of rate design and rate structure criteria.

In its decision and order issued on October 29, 1980 pursuant to this review, the UTC rejected the "lifeline" concept for rate setting. This decision was made on the basis that lifeline rates are intended to achieve social goals by subsidizing the cost of power for the "basic needs" of low-income customers, and that such social goals are not an appropriate function of the UTC. However, the UTC decided that the concept of baseline rates (and, implicitly, inverted rates) was appropriate in establishing rate structures for residential customers. The UTC based this decision on an acceptance of the inverse elasticity rule as applied to electrical energy demand, and the fact that the baseline rate would apply to all customers. Thus, the UTC ruled it would require all private electric utilities to adopt a baseline rate structure, where the base block of energy would fall in the range of 400 to 600 kwh per month.[3]

Puget Power and Washington Water Power

Puget Power and Washington Water Power, two investor-owned utilities regulated by the UTC, both have inverted residential rates, and, prior to the UTC "generic rate design" order, petitioned the UTC for permission to invert them even more steeply. Puget Power has asked for the establishment of a 400 kwh "basic needs" block above which the rate per kwh will be much higher. According to Puget Power's testimony "this will have the effect of inverting the rate more steeply and thereby, hopefully, encouraging greater conservation."[4] Washington Water Power has asked for a basic needs block of 600 kwh above which the rate will be inverted sharply. John Buergel, a rates accountant for Washington Water Power, testified that the change was necessary because "...residential electric customers are presently making decisions to install electric heat based on a price which does not fully reflect the actual cost of serving residential customers. The company believes that its rates should provide a distinct price signal reflecting the current cost of serving electric power. As I have stated earlier, the proposed rate design will encourage all residential customers to conserve in their usage of electric energy."[5]

California

In 1975, the California State Legislature adopted a bill which required the creation of inverted "lifeline" rates for residential users of electricity and gas. The lifeline amount varies by climate zone and end use characteristics; electric water heating lifeline, a space heating lifeline which varies by climate, and an air conditioning lifeline which varies by climate. At first, the establishment of the lifeline resulted in only mild rate inversions, but recent cost increases have elevated the rates above lifeline blocks. (See the PG&E lifeline rate example under Lifeline Rates in Chapter 2.)

It is hard to determine the impacts of California's lifeline rate on consumption because any conservation effect of the rate is mixed with the conservation effects of California's home weatherization programs, new building standards, and other conservation activities. One utility, Pacific Gas and Electric, analyzed the effect of the lifeline on consumption, and found "relatively stronger price responsiveness exhibited by those customer groups in the sample who have higher usage levels."[6]

The California lifeline rate has experienced certain administrative problems which may have acted to counter the conservation impact of the lifeline. First, each residential homeowner notifies his utility about what lifeline amounts he qualifies for. This allows people to receive lifelines which they may not be qualified for by misrepresenting facts. For instance, Pacific Power and Light determined that in one service area the number of customers receiving a lifeline space heating discount exceeded by 20% the actual number of space heating customers according to a random sample utility survey.[7]

Second, lifeline allowances are allowed for all vacation homes. Since the lifeline allowance will rarely be exceeded in a house which gets infrequent use, this is a disincentive to conservation.

Third, the California PUC has recently extended lifeline allowances to uses like air conditioning. This also reduces the incentive to conserve.

TVA

The TVA currently allocates the benefits of low-cost hydro power an initial 500 kwh block for residential customers. This has resulted in an imbedded cost-based inverted rate structure for almost all of TVA's residential customers. The following is a typical TVA rate:

Customer charge	$2.30
First 500 kwh	2.67¢ kwh
Additional kwh	3.11¢ kwh

(Source: TVA, Report on Ratemaking Standards)

The residential consumption of electricity in the TVA system decreased by 10% last year, but it is hard to tell how much of this decrease came from the rate structure, and how much came from TVA's ambitious conservation loan program.

Current TVA thinking is that inverted rates are desirable and in the future TVA plans to continue the inverted rate.[8]

Vermont

The State of Vermont currently employes a baseline rate. It has a limited amount of hydro power which it makes available for residential consumers. Consequently, the Vermont PUC has established initial blocks of 200-300 kwh for the state utilities in which the benefits of the cheaper hydro power are included. Power above the initial block is priced at what it costs from thermal plants. In addition, seasonal rates have been implemented for Vermont's largest utility. The existing baseline/seasonal rate has caused a sharp inversion in residential rates. The following is the winter residential rate structure of Vermont's largest utility.

Customer charge	$6.58
First 200 kwh	2.75 kwh
All additional kwh	7.19¢ kwh

(Source: Central Vermont Public Service Corp.)

This rate has acted to dampen the use of electric space heating. This rate has in effect made electricity a more expensive heating fuel than oil and has dampened the growth in electric space heating use. For instance, the Central Vermont Public Service Corporation, which has both seasonal and baseline rates reported only a 1% growth in the use of electricity in 1978-79. Ray Collender, a rate analyst for the Vermont Public Service Board, attributed this to the reduction in space heating usage due to the inverted rates. He also mentioned that the state's second largest utility does not have seasonal rates and has a considerably greater amount of space heating use, and a higher growth rate. In light of this experience, the Vermont Public Service Board has recommended that the state's second largest utility institute seasonal rates for residential customers.[9]

FOOTNOTES TO CHAPTER 3

[1]Seattle City Light, Position Papers for Ratemaking Standards, prepared pursuant to the requirements of the Public Utility Regulatory Policies Act of 1978, Section 111, (March, 1980), pp. 22-25.

[2]Memo from Harry Huggins, Legislative Auditor to Randy Revelle, "Residential Electric Rate Structure". (June 23, 1980), p. 13.

[3]Washington Utilities and Transportation Commission, Commission Decision and Order; Cause No. U-78-05. (October 29, 1980), pp. 20-21.

[4]Swartzell, Richard. Prepared testimony before Washington State Utilities and Transportation Commission; Cause U-80-10, p. 5.

[5]Buergel, John. Prepared testimony before Washington State Utilities and Transportation Commission; Cause U-80-13, pp. 3-4.

[6]Pacific Gas and Electric Company, Energy Cost Adjustment: Status of Residential Elasticity Studies, submitted to California PUC in response to Decision No. 91335, Application No. 60007, (N.D.), p. 21.

[7]Shue, John. Pacific Power and Light Company. Prepared testimony before Washington State Utilities and Transportation Commission; Cause U-78-05, p. 6.

[8]Telephone conversation with Roy Van Allen, TVA, (1980).

[9]Telephone conversation with Ray Collender, Vermont Public Service Board, (1980).

CHAPTER 4: APPLYING THE BASELINE CONCEPT

The evidence cited in the preceding chapters clearly support the concept of baseline inverted rates as means of providing the residential consumer with a more accurate price signal to encourage more efficient electricity use. The general arguments may be summarized as follows:

(1) The empirical research clearly shows the importance of the price elasticity of residential demand for electricity. Significant price increases can be expected to lead to a significant decrease in consumption. While there is some disagreement about how elastic demand is, there is no disagreement that elasticity is important.

(2) Long-run price elasticities are consistently greater than short-run elasticities. This indicates that over time, consumers have a significant ability to react to increased electricity prices by improving the energy efficiency of their homes, appliances and heating and cooling equipment and by turning to alternative fuels.

(3) Although the evidence is less overwhelming, it would appear that the demand of those residential customers who consume small amounts of electricity is less price elastic than the demand of those who consume large amounts of electricity. This conclusion has considerable intuitive appeal and is supported by other evidence. The small user's loads are generally limited to lighting and small appliance use. The opportunities for reducing these loads, short of curtailment, are minimal. The large residential user, however, is typically an electrical heating customer. As the data from the BPA survey of residential energy use indicates, a large percentage of electrically-heated Washington homes are not insulated and weatherized to economically optimal levels.[1] Similarly, as indicated by the data in Table 4-1, on the average, electric homes in Washington use considerably more electricity per annual degree day (a measure of the severity of the climate) than do all electric homes located in

regions with higher power costs.[2] This information indicates the large residential electricity user in Washington has a considerable potential for economically reducing electricity use.

(4) The evidence also indicates that the residential consumer makes consumption and conservation decisions on the basis of the marginal price rather than the average price (e.g., total bill) of electricity. This means that inverted rate structures will encourage more efficient electricity use. Efficient use should also be enhanced as utilities better inform their customers about the applicable rate structures as suggested in the PURPA "Information to Consumers" standards (Section 113(b)(3) and 115(5), Public Utilities Regulatory Policy Act of 1978). However, even if this were not the case, inverted rate structures are still potentially important in that they can be used to focus cost increases on that segment of demand which is most price elastic.

(5) Baseline rates <u>are</u> cost-based. The baseline concept has been attacked as not being cost-of-service based and, therefore, in violation of the fair cost apportionment objective. First, it must be again noted that the determination of cost of service is a highly arbitrary process which in all likelihood does not result in accurate cost apportionment. Even if it did, however, in a situation like that facing Washington utilities, it is quite possible to offer a baseline quantity of energy at comparatively low "cost-based" rates. This is because each utility has available to it a large block of energy from existing low-cost hydro power resources. Apportioning a fraction of this power to residential customers at a rate which reflects its cost of production and delivery can certainly be said to be a cost-based approach, even though this base block rate is less than average cost.

Having summarized these conclusions, it is important to examine the effect of adopting baseline rates on a typical utility. The key question is, how will total consumption and therefore utility revenues be affected by the adoption of baseline rates? This question is examined under different assumptions about how, on the average, customers will react to changes in rate structure.

COMPARISON OF ELECTRIC HEATING LOADS

CITY	UTILITY	ANNUAL HEATING DEGREE DAYS	SYSTEM-WIDE AVERAGE RESIDENTIAL USE	ELECTRIC HEAT CUSTOMER AVERAGE USE	ELECTRIC HEAT CUSTOMER AVERAGE USE PER HEATING DEGREE DAY
Seattle	Seattle City Light	4424	12,321	23,400	5.29
Tacoma	Tacoma City Light	4835	15,813	22,000	4.55
Olympia	Puget Power	5236	15,235	20,103	3.77
Spokane	Wash. Water Power	6835	14,427	26,000	3.80
Everett	Snohomish PUD	5347	21,283	27,000	5.05
Colorado Spr.	CO Spr. Municipal	6423	5,701	21,602	3.36
Wilmington, DE	Delmarva Power	4920	8,099	15,307	3.11
St. Paul, MN	Northern States Power	7966	6,879	20,350	2.55
Helena, MT	Montana Power	8129	7,308	22,500	2.77
Racine, WI	Wisconsin Electric	7635	7,187	18,689	2.45
Wichita, KS	Kansas Gas & Electric	4620	9,413	16,790	3.63

Source: All Electric Homes, U.S. Department of Energy; October, 1978

The Thermal Environment: Conditioning and Control, Burgess H. Jennings, 1978

A computer simulation was developed to provide an initial answer to this question. The input to the simulation is the monthly distribution of consumption (the number of kilowatt hours consumed by customers whose total demand is within a certain range) with an initial rate structure; the initial rate structure; the alternative rate structure to be evaluated; and the assumed price elasticity of demand. Elasticity may be constant or it may be a function of the level of demand. Consumers may be assumed to react to either the marginal price (rate) or total cost. The output of the simulation is a new distribution of consumption and associated revenues estimated to result from the new rate structure. It must be emphasized that the simulation does not yield a "prediction" of what demand and revenues will be. The simulation does not take into account population growth, growth or decline in the economy, or the myriad of other factors which affect total demand. It is a "ceteris paribus" simulation, assuming all other things to be equal. It is not a predictive tool, but it is useful for comparing the probable effect of alternative rate structures. By permitting the testing of a number of different assumptions about rate structure, elasticity, and consumer response, the simulation allows the analyst to compare with some confidence the range of results to be expected with alternative rate structures.

For this study, bill frequency data were obtained for a representative Washington utility, referred to here as "Skookum PUD" for purposes of confidentiality. These data show the number of customers whose total consumption is within certain kilowatt hours per month blocks and the total consumption of those customers.

The data analyzed were for a "typical" January and July. (In actual utility application, it would be necessary to analyze each billing cycle.) The rate structure to which these data correspond was flat with an energy charge of $.0132 per kilowatt hour and a $2.75 per month customer charge. If Skookum PUD had chosen to establish a baseline residential rate structure, what would that rate look like and what effect would it have on consumption and revenues?

The Winter Baseline

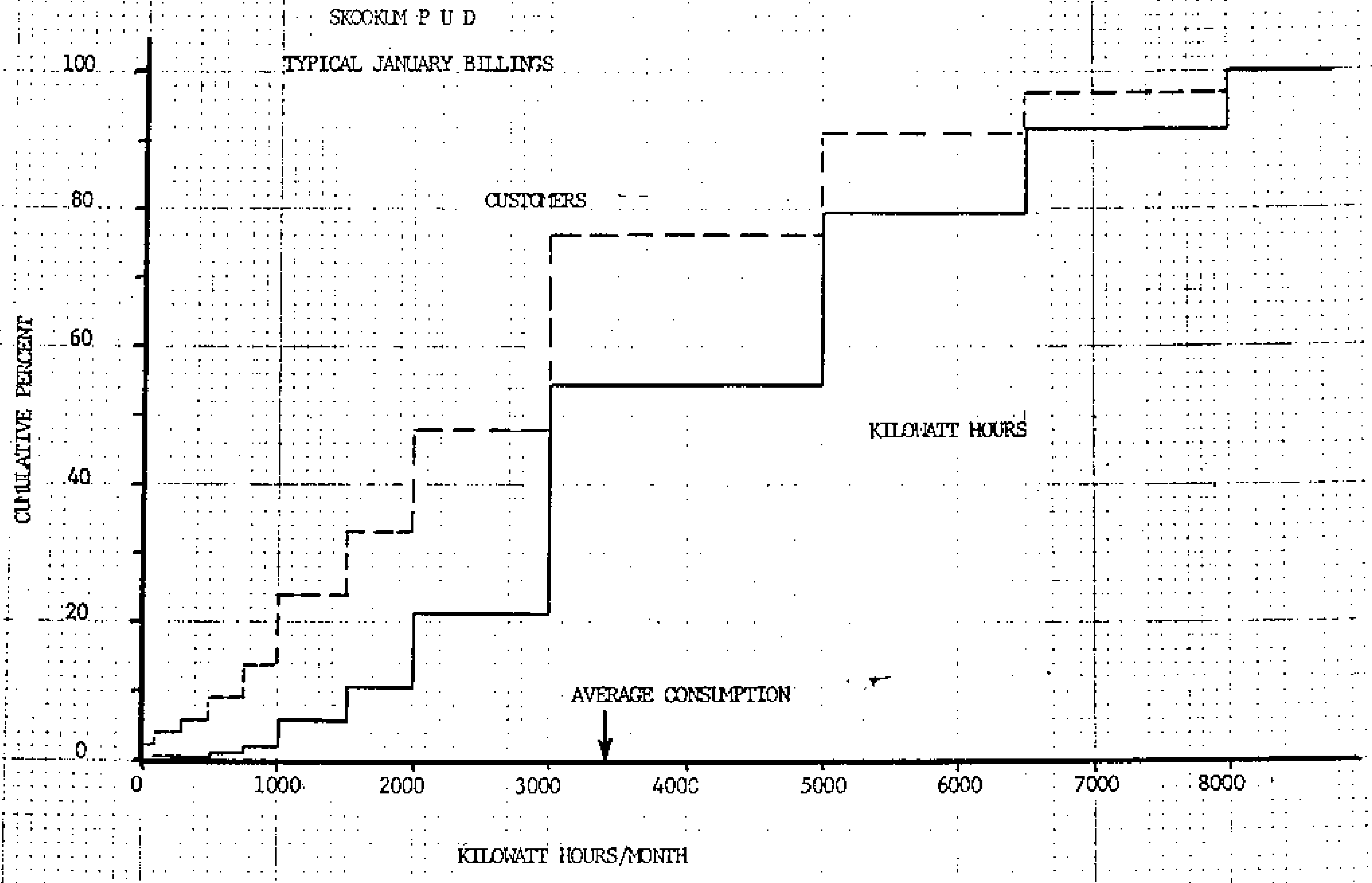
Design of a baseline rate structure begins with an examination of the utility's billings. Figure 4-1 shows the January billings in terms of the cumulative percent of consumption and customers. For example, this figure shows that approximately 21% of the total kilowatt hours were consumed by customers whose consumption was less than 3000 kilowatt hours. This group represented 48% of the total customers. Average consumption for the month was approximately 3400 kilowatt hours. From these figures, it is clear that Skookum PUD has a high saturation of electric heat.

Figure 4-1 shows that very little of the total consumption is attributable to customers whose consumption is less than 1000 kilowatt hours per month (about 2% of the consumption and 14% of the customers). For this reason, 1000 kilowatt hours was chosen as the baseline level.

The baseline rate structure designed for Skookum PUD is illustrated in Figure 4-2 for comparison with the actual flat rate structure. The rate below 1000 kilowatt hours was set at $0.00932/kwh and the customer charge was held at $1.80 per month. These figures were chosen because they were the rate and service charge existing prior to an increase in the wholesale cost of power to the utility, part of which was attributable to the cost of new generating facilities. While there were non-resource-related cost increases which could have been imposed on the baseline rate and service charge, this was not done in the interest of increasing the rate above the baseline so as to more closely approximate the marginal cost of electric energy.

The rate above 1000 kilowatt hours was set at $0.017/kwh in order to recover revenues lost by the lower baseline rate, lower service charge and the expected conservation response to the higher rates above the baseline. This rate is well below the marginal cost of electricity. It does, however, approximate this cost much better than does the $.0132/kwh flat rate.

Figure 4-1


SKOOKUM P U D
TYPICAL JANUARY BILLINGS
100
80
60
40
20
0
CUMULATIVE PERCENT
CUSTOMERS
KILOWATT HOURS
AVERAGE CONSUMPTION
0
1000
2000
3000
4000
5000
6000
7000
8000
KILOWATT HOURS/MONTH

The comparative impact of the alternative rate structures on the cost facing an individual customer is illustrated in Figure 4-3. Because of the lower baseline rate and service charge, the baseline rate structure results in lower costs for all those consuming 2200 kilowatt hours or less per month. Referring back to Figure 4-1, this means that between 33% and 48% of the customers would have lower costs with the baseline rate even before any conservation response is taken into consideration. Conversely, customers with higher usage, generally space-heating customers, will face higher costs.

From the standpoint of conservation, the ideal situation or "best case" occurs when customers respond to the marginal price and when price elasticity increases with consumption. This situation is illustrated in Figure 4-4, where demand is assumed to be relatively inelastic at low levels of consumption and becomes more elastic with increasing consumption.

The result of plugging these assumptions into the simulation model are illustrated in Figure 4-5. This shows the number of kilowatt hours consumed in each kilowatt hour block for the original flat rate and the baseline. As this illustrates, there are slight increases in consumption in the baseline block (1000 kilowatt hours or less) with the baseline rate. This is more than made up for, however, by decreased consumption above the baseline. In total, the net long-run energy savings estimated to result from the baseline rate structure amount to almost 16%. In addition, with the baseline rate structure, a higher percentage of customers would have lower total bills. (Note that the consumption blocks have generally shifted to the left as well as having reduced consumption within them.)

The baseline rate structure does result in a slight revenue deficit (0.6%). This could be handled in several ways: The service charge could be increased very slightly (least preferable); the above baseline rate could be increased slightly (preferable because it would result in greater conservation); or the deficit could be recovered (and then some) from rate credits to be granted by BPA for conservation savings resulting from the rate structure. This point deserves some amplification.

FIGURE 4-2
SKOOKUM PUD
WINTER RATES

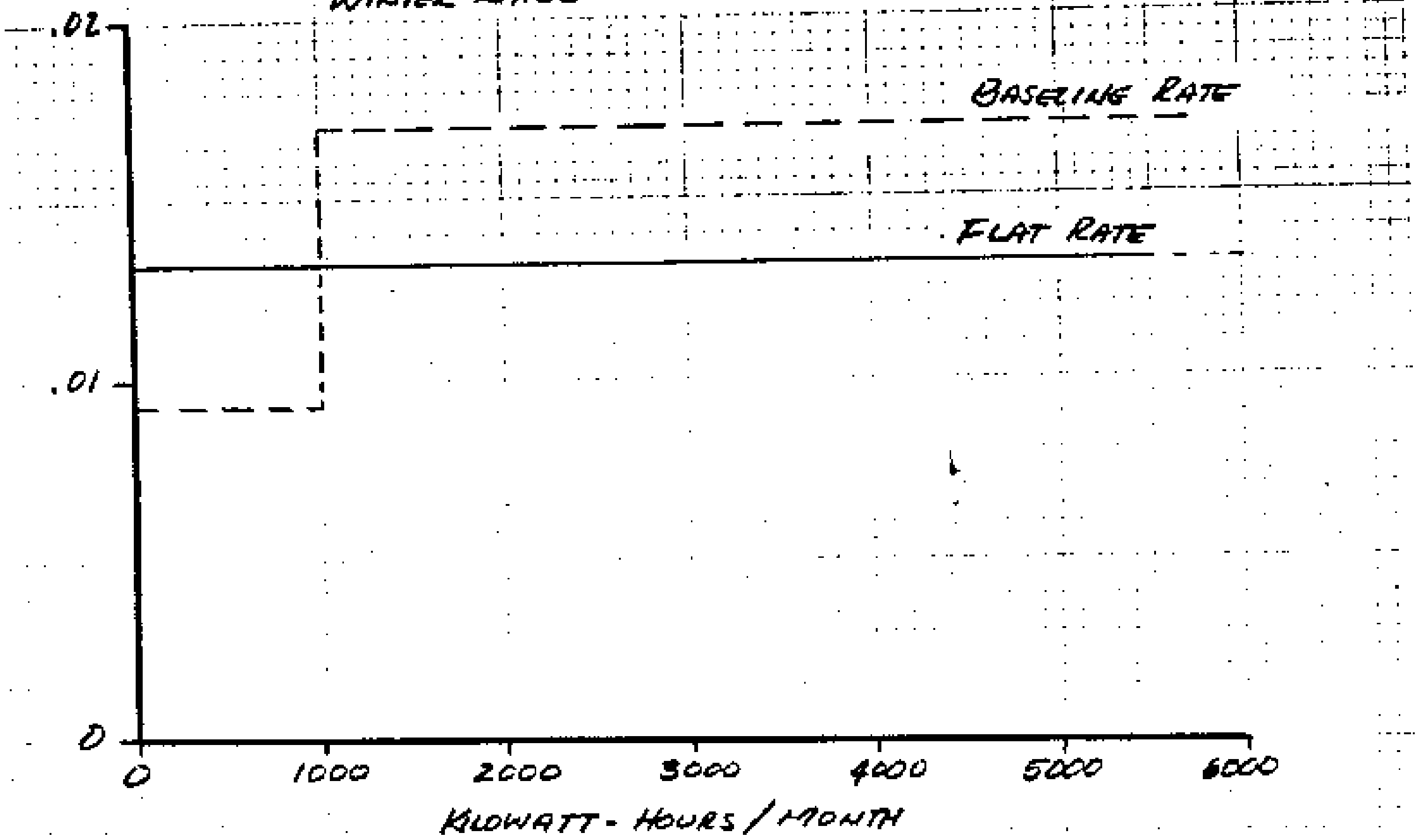
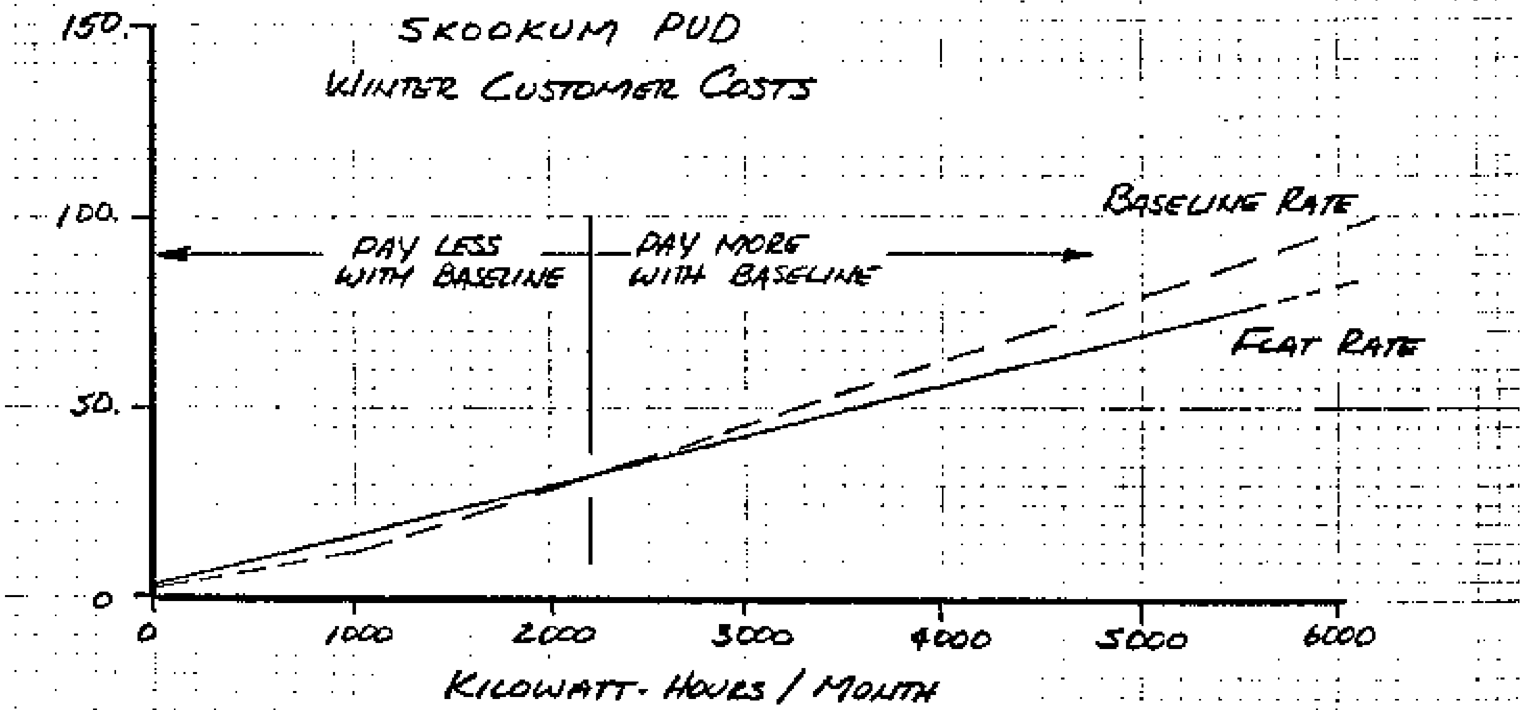


FIGURE 4-3
SKOOKUM PUD
WINTER CUSTOMER COSTS



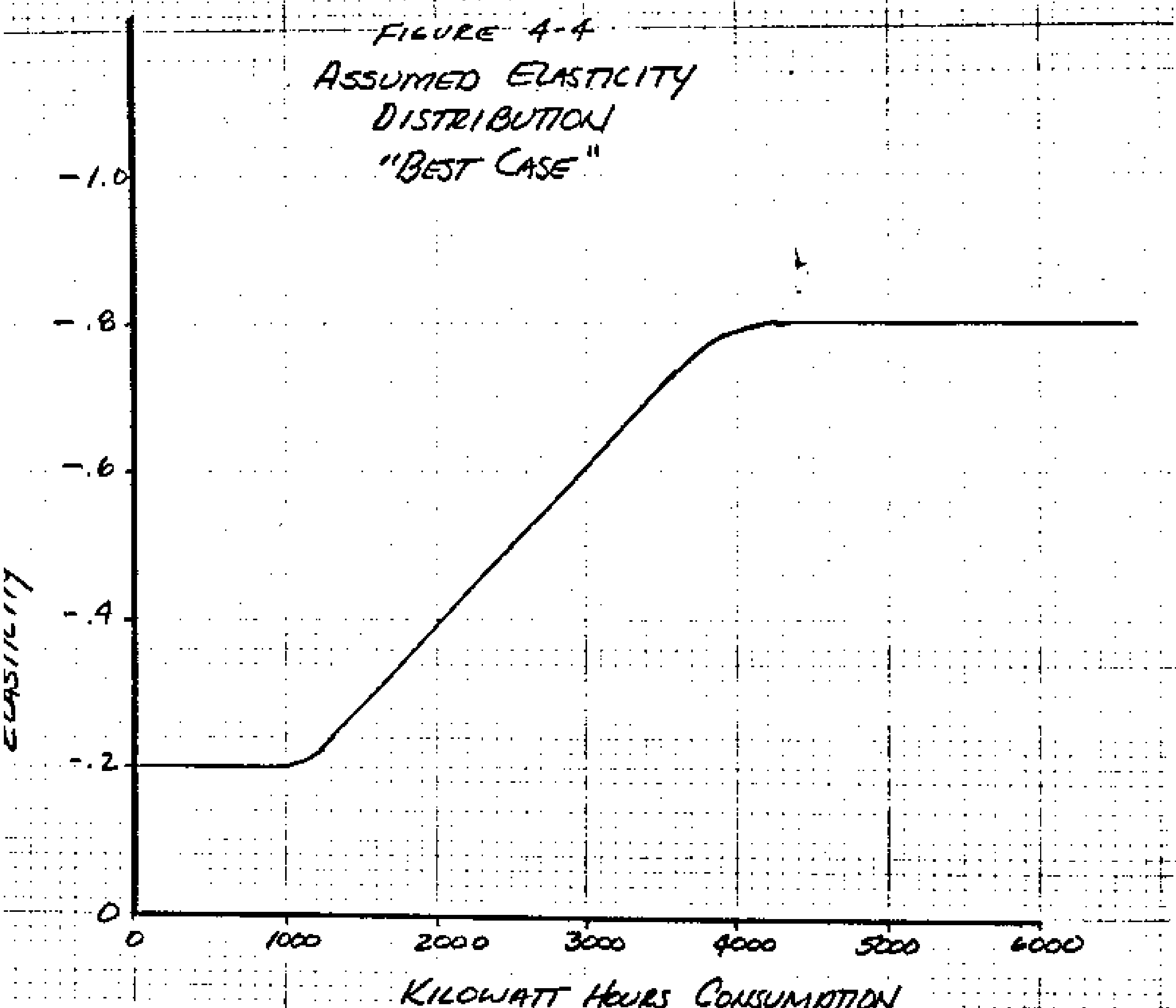


FIGURE 4-4
ASSUMED ELASTICITY
DISTRIBUTION
"BEST CASE"
-1.0
-.8
-.6
-.4
-.2
0
ELASTICITY
0
1000
2000
3000
4000
5000
6000
KILOWATT HOURS CONSUMPTION

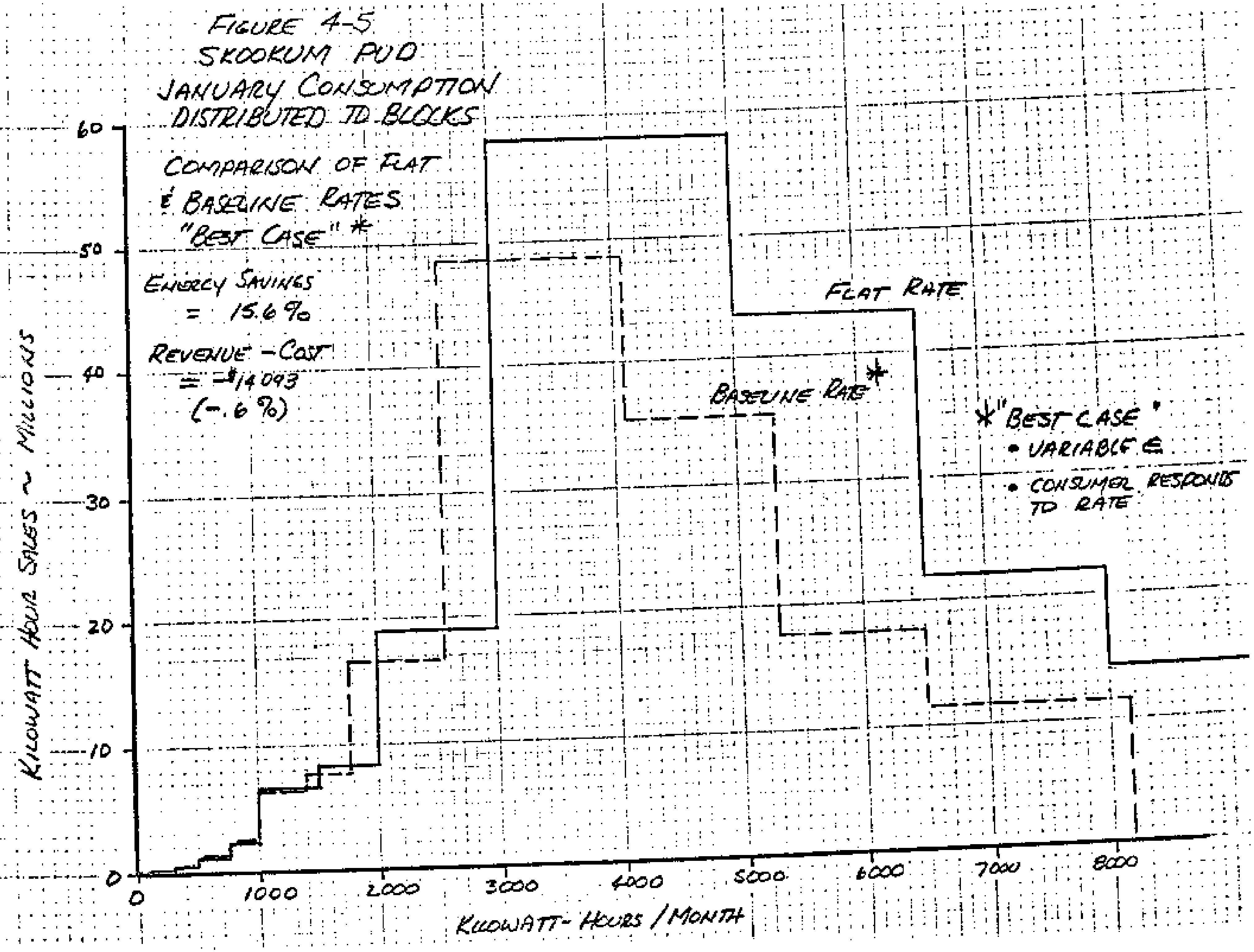


FIGURE 4-5
SKOOKUM PUD
JANUARY CONSUMPTION
DISTRIBUTED TO BLOCKS
COMPARISON OF FLAT
& BASELINE RATES
"BEST CASE" *
ENERGY SAVINGS
= 15.6%
REVENUE - COST
= -$14,093
(-.6%)
FLAT RATE
BASELINE RATE *
*"BEST CASE"
• VARIABLE ∈
• CONSUMER RESPONDS TO RATE
KILOWATT HOUR SALES ~ MILLIONS
KILOWATT-HOURS / MONTH
0
10
20
30
40
50
60
1000
2000
3000
4000
5000
6000
7000
8000

Section 6(h)(5) of the Pacific Northwest Electric Power Planning and Conservation Act stipulates that "Retail rate structures which are voluntarily implemented by the Administration's customer and which induce conservation shall be considered, for the purposes of this subsection, to be (A) conservation activities independently undertaken or carried on by such customers, or (B) customer-owned renewable resources, and shall qualify for billing credits...". The amount of this credit would be equal to the savings to BPA resulting from the rate structure. This would be the difference between the cost to BPA, e.g., marginal cost, and their wholesale rate to the utility. This amount would greatly exceed the revenue deficit experienced by the utility. The excess could be either directly rebated to consumers or used to finance further conservation efforts. A cautionary note, however, is appropriate. It remains to be seen just how BPA will implement this directive.

From the standpoint of conservation, the "worst case" situation is to have the consumer respond to total rather than marginal costs and with a constant, relatively low price elasticity. This situation is illustrated in Figure 4-6. The result is that the conservation savings resulting from adoption of the baseline are greatly reduced <u>but are still significant</u> (3.6%). There is, however, a modest but significant revenue surplus (7.8%). Were this to occur, it would present some problems which are difficult but not intractable. The surplus could be rebated, but this would present the difficulty (administratively and politically) of determining who gets how much. The surplus could be used to finance conservation. This would have the advantage that those who had contributed most to the surplus would be the likely beneficiaries. The winter surplus could be used to reduce rates in the summer, during which time demand might be expected to be relatively less elastic. The best approach, however, would be to adopt a somewhat more sophisticated rate structure. The alternative evaluated here was the most simple, one-step structure. A more sophisticated, two-step inverted rate structure could be devised to minimize excess revenues. It should be pointed out that this worst case is <u>not</u> what the evidence reviewed earlier in this study would lead one to expect. That evidence tends to indicate that the "best case" is more likely.

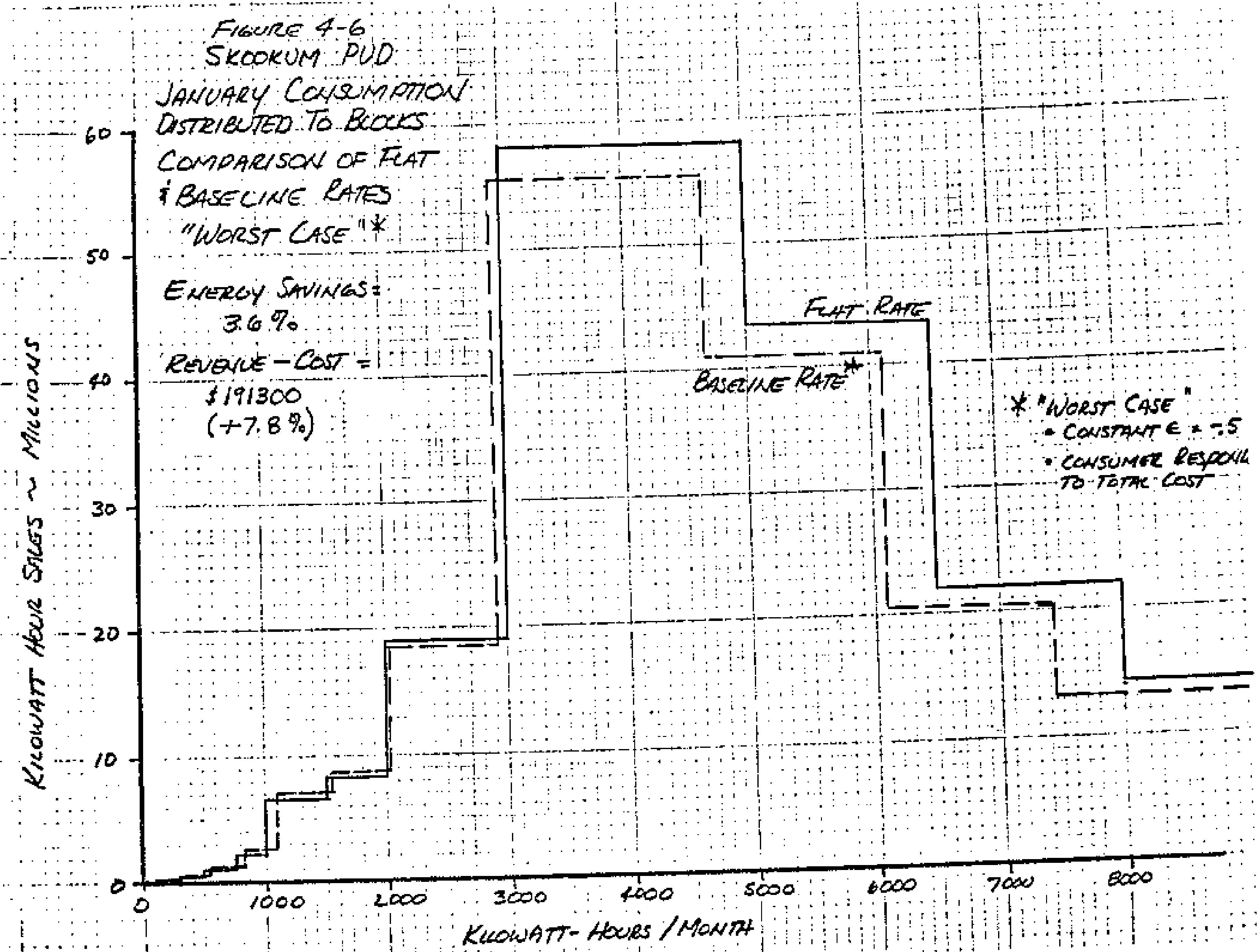


FIGURE 4-6
SKOOKUM PUD
JANUARY CONSUMPTION DISTRIBUTED TO BLOCKS
COMPARISON OF FLAT & BASELINE RATES
"WORST CASE"*
ENERGY SAVINGS = 3.6%
REVENUE – COST = $191300 (+7.8%)
FLAT RATE
BASELINE RATE*
* "WORST CASE"
• CONSTANT ∈ = -.5
• CONSUMER RESPONSE TO TOTAL COST
KILOWATT HOUR SALES ~ MILLIONS
0
10
20
30
40
50
60
0
1000
2000
3000
4000
5000
6000
7000
8000
KILOWATT-HOURS / MONTH

The Summer Baseline

For the summer, the baseline rate structure was re-designed since summer loads are much different than winter loads. The "basic requirements" are reduced because days are longer and people are spending more time out of doors. Heating loads effectively disappear and are replaced, to a much lesser degree, by air conditioning and, perhaps, swimming pool heating loads.

The July billings, shown on Figure 4-7, illustrate this. Average use has dropped to a little over 1100 kilowatt hours and the entire distribution has shifted to the left.

The summer baseline block was set at 400 kilowatt hours as shown in Figure 4-8. The rates, in this instance, were kept the same as in the winter case. The resulting cost comparison is shown on Figure 4-9.

If we again assume that the consumer responds to marginal rates and that elasticity varies with consumption as shown on Figure 4-4, the resulting changes in consumption is as shown on Figure 4-10. The energy savings amount to 8.3% while again there is a small revenue deficit (2.1%). Again, this could be easily remedied by a slightly higher rate for electrical energy above the baseline.

In retrospect, it seems logical that summer demand might be less elastic than winter demand and that the elasticity would vary less with demand. To test the effect of these assumptions, a run was made with a constant elasticity of -.3 (again assuming that the consumer responds to rate). This resulted in a somewhat reduced energy saving (6.7%) and a very small revenue deficit (1.1%).

If it is assumed as a worst case that the consumer responds only to total cost, and that elasticity is constant and relatively small (again, -.3), the results are as illustrated in Figure 4-11. The energy savings are minimal (1.1%) and there is a small revenue surplus (2.4%). Again, however, this "worst case" is also probably a least likely case.

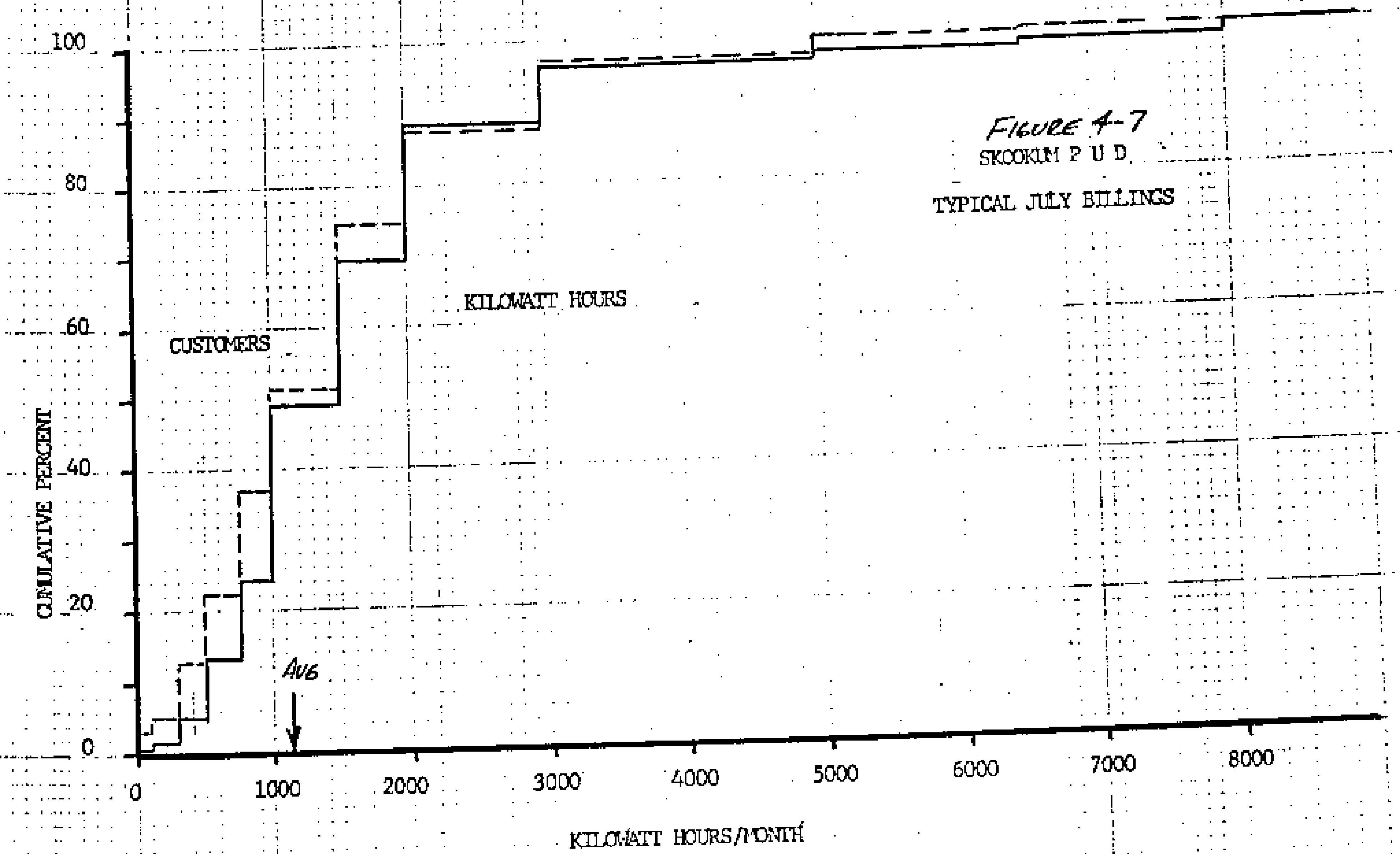


FIGURE 4-7
SKOOKUM P U D
TYPICAL JULY BILLINGS

FIGURE 4-8
SKOOKUM PUD
SUMMER RATES

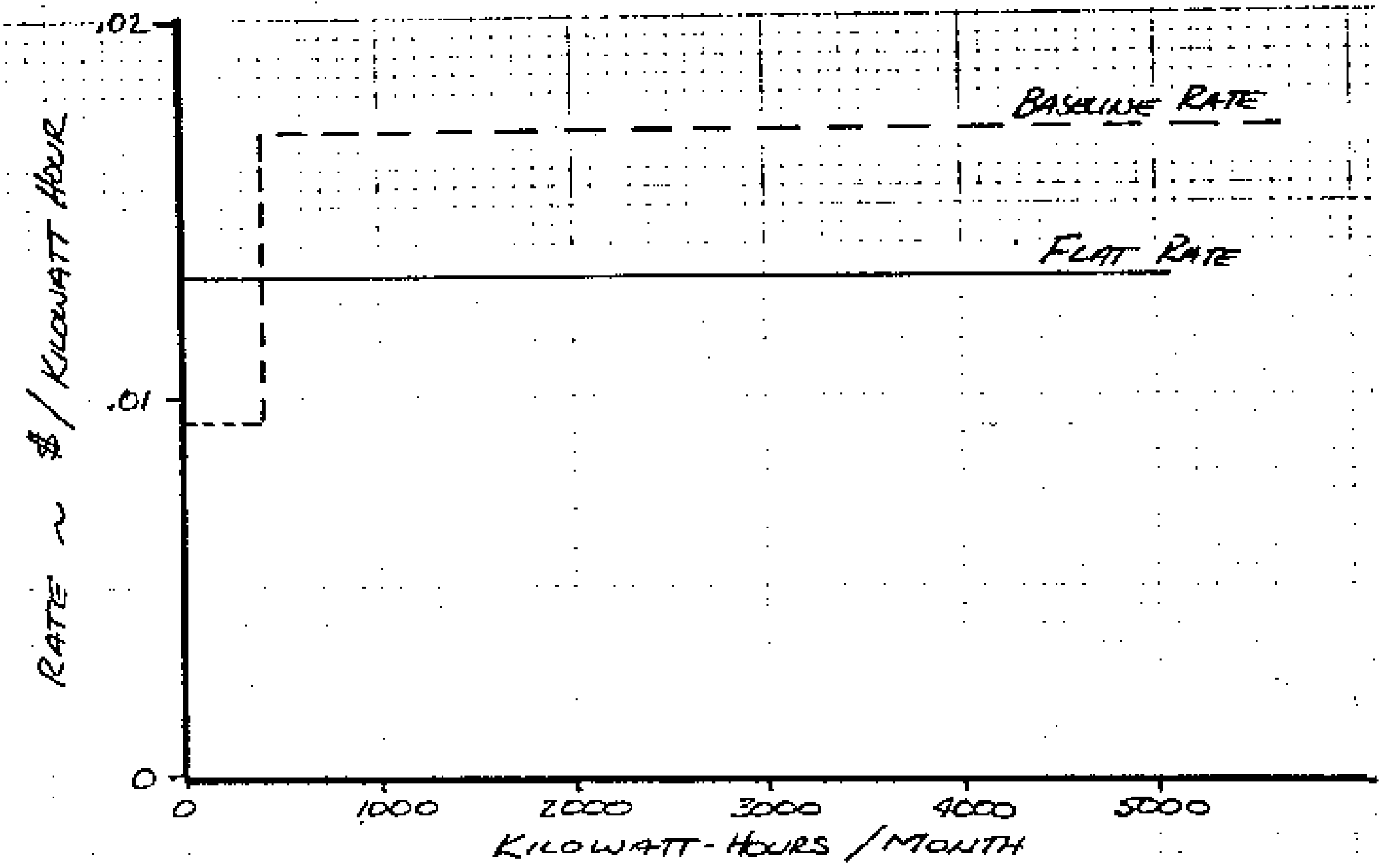


FIGURE 4-9
SKOOKUM PUD
SUMMER CUSTOMER COSTS

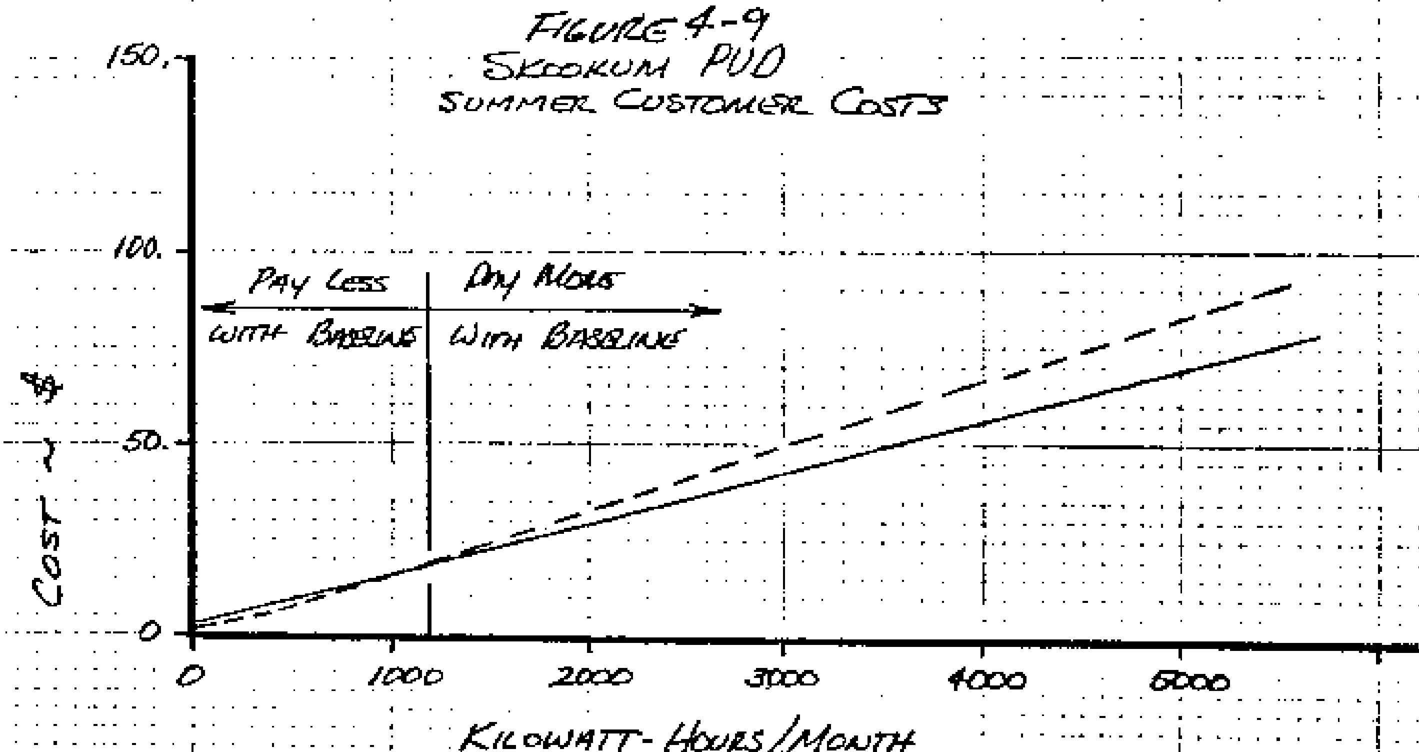


FIGURE 4-10
SKOOKUM PUD
JULY CONSUMPTION DISTRIBUTED
TO BLOCKS

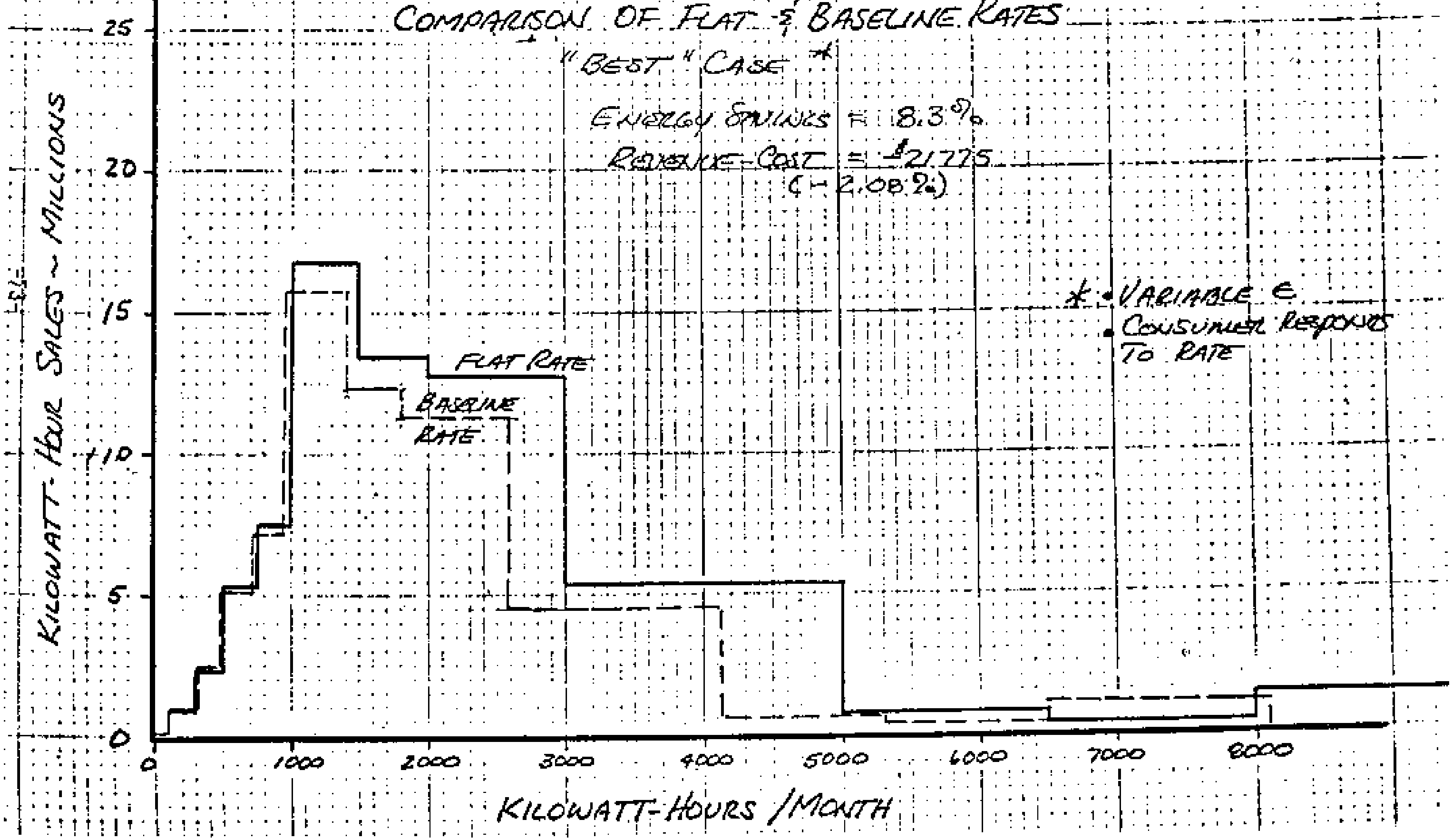
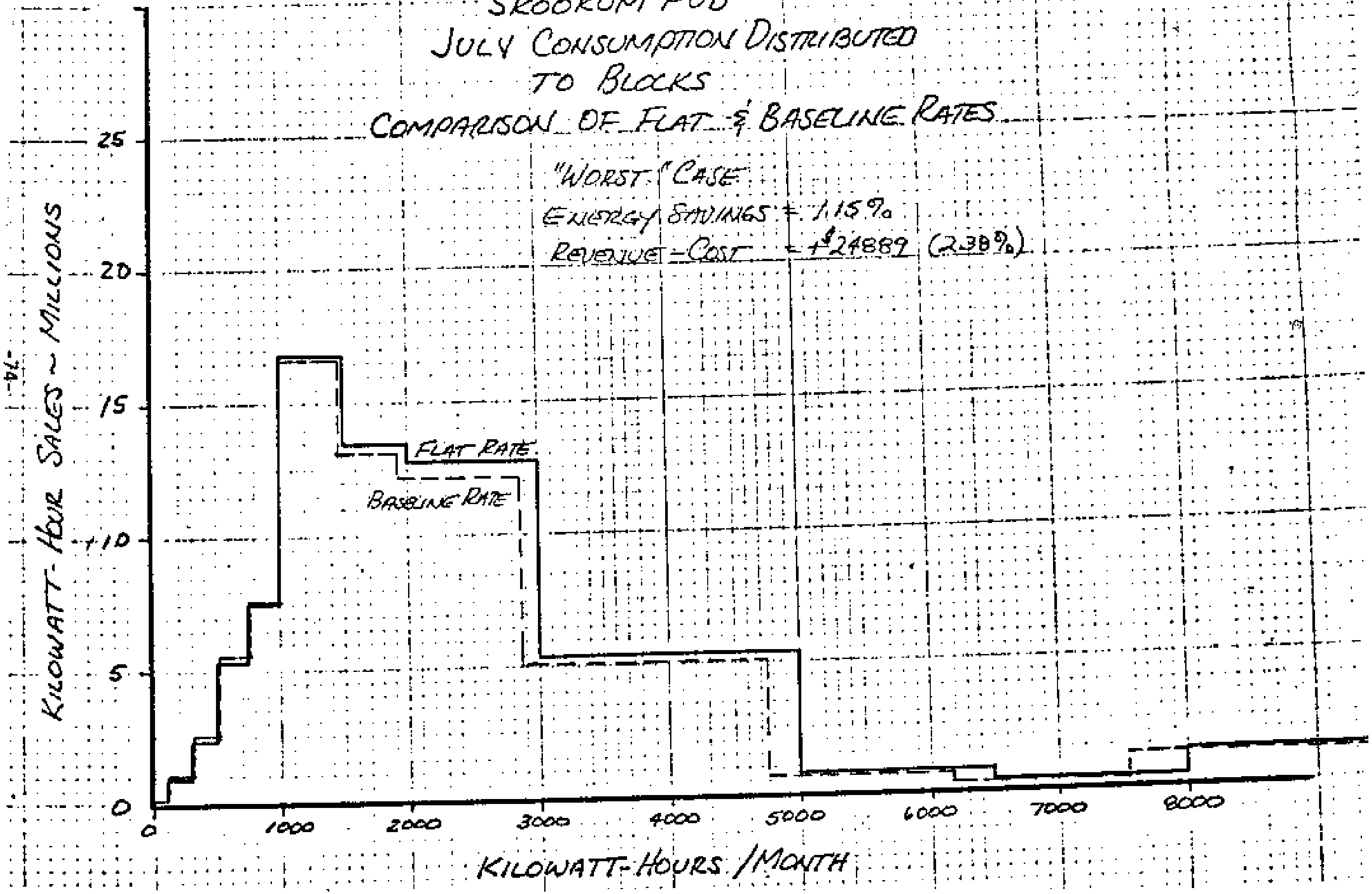


FIGURE 4-11
SKOOKUM PUD
JULY CONSUMPTION DISTRIBUTED TO BLOCKS
COMPARISON OF FLAT & BASELINE RATES

"WORST" CASE

ENERGY SAVINGS = 1.15%

REVENUE - COST = +$24889 (2.38%)



Baseline Rates and the Poor

The baseline inverted rate is often criticized as either being a social welfare measure designed to effect income redistribution through rates or as being injurious to low income groups. These assertions miss the point of baseline inverted rates.

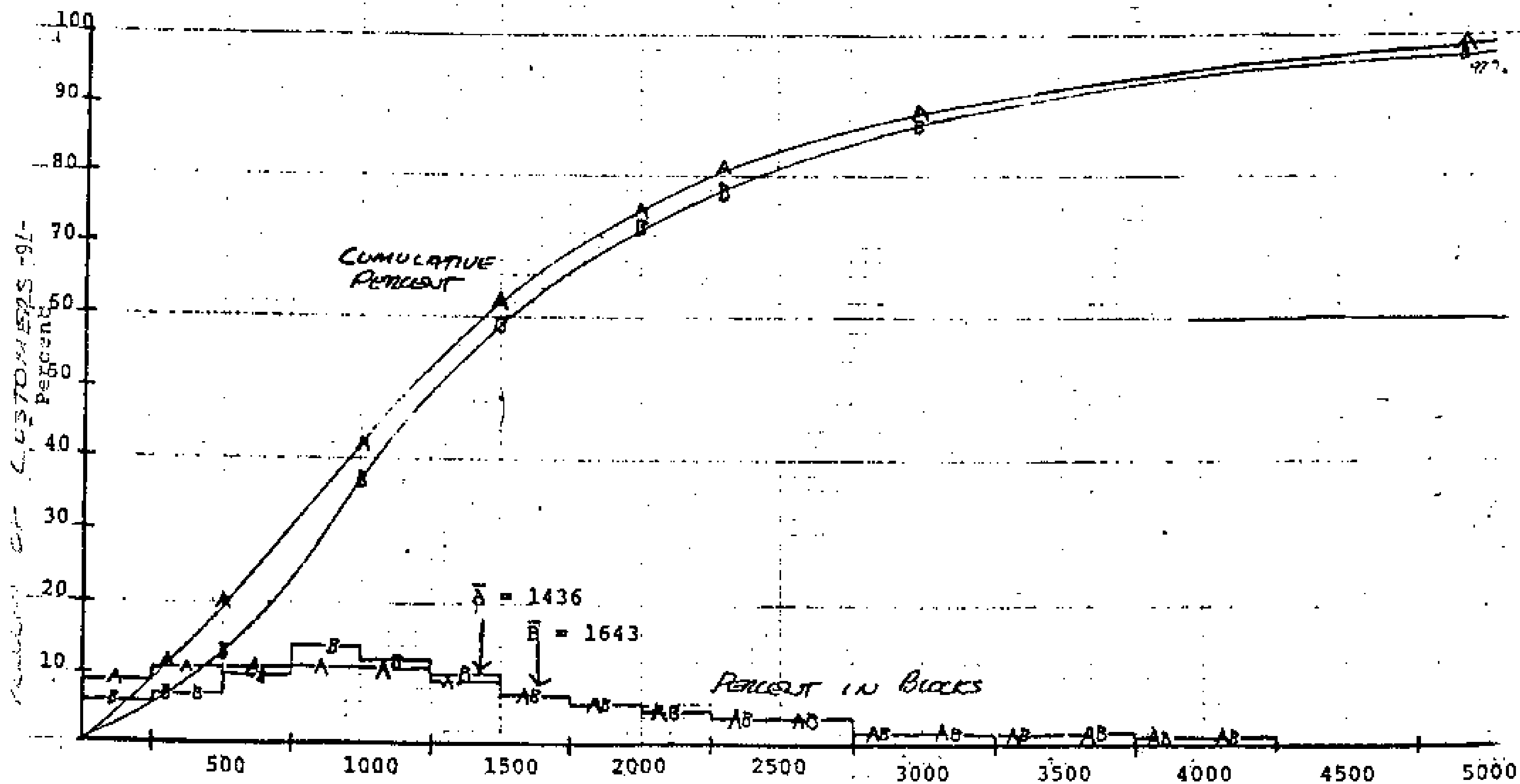
The objective of the baseline inverted rate is economic efficiency not income redistribution. To the extent that low income households' electricity use falls below the "cost cross-over" point (see Figure 4-3), they will benefit from the baseline, as will all others with such low levels of demand. In general, electricity use increases with increasing income, but only modestly so.[3,4] Information on electrical use as a function of income is not overly abundant. Data from one Northwest utility are shown on Figure 4-12. For this utility at least, a greater percentage of low income customers would benefit from a baseline rate than would other customers. There are clearly some, however, who would face increased costs from a baseline rate structure.

The main point to be made, however, is that the objective of the baseline rate is to bring about economically efficient use of electricity. In so doing, the overall rate of increase of electricity costs will be slowed, ultimately benefiting both poor and affluent consumers.

Conclusion

The foregoing analysis indicates that, in the long run, the adoption of a baseline inverted rate structure will lead to more efficient use of electrical energy, and substantial energy savings while returning adequate revenues to the utility. Indeed, the major problem would seem to be the possibility of a revenue surplus <u>if</u> consumers react purely to total cost rather than rate. This problem can be overcome through more sophisticated rate designs than have been analyzed here. More importantly, however, this problem can also be overcome by better informing consumers about the rate structure affecting them.

FIGURE 4-12
PORTLAND GENERAL ELECTRIC
FEBRUARY, 1972 BILLS
TOTAL RESIDENTIAL
A = WELFARE CUSTOMERS
B = ALL CUSTOMERS



SOURCE: TESTIMONY OF WALLACE GIBSON
BEFORE THE UTILITIES AND TRANSPORTATION COMMISSION, APRIL 1979

If consumers are aware they are paying more at the margin than on the average, they will also become aware that the cost-effectiveness of conservation and alternative fuels is greater than they might otherwise have thought. The end result will be more efficient use of the state's scarce and ever more costly electrical energy resources.