A proposed method of long run incremental cost pricing of electrical rates to Montana Power Company residential customers
by Robert John Crnkovich

A thesis submitted in partial fulfillment of the requirements for the degree of MASTER OF SCIENCE in Applied Economics
Montana State University

Abstract:
This study designs an electricity rate schedule for the residential customer class of the Montana Power Company. The rates are designed to provide correct price signals to a majority of consumers with respect to the long run incremental costs of electrical power while still meeting the revenue constraint set by the Montana Public Service Commission. The rates are determined on the basis of the generation, transmission, and distribution costs of existing and incremental electrical facilities. The incremental generation costs is found to be significantly higher than the cost of existing generation. The tail-block energy charge is based on this higher incremental cost of generation. A lower interior block price based on the weighted cost of existing hydro and thermal generation is used to meet the revenue constraint. The resulting long-run incremental cost (LRIC)-based rate schedule incorporates a two block structure of an inverted type and a fixed customer charge. Implications of adopting LRIC-based pricing in electrical rates are discussed. These may include reduced future electricity consumption and the corresponding need for new power plants, reduced environmental pollution from coal-fired power plants, more awareness of electricity bills and electricity consumption of various appliances, and reduced Montana Power Company financing difficultires.

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Date September 14, 1978

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OF ELECTRICAL RATES TO MONTANA POWER COMPANY RESIDENTIAL CUSTOMERS

by

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A thesis submitted in partial fulfillment
of the requirements for the degree

of

MASTER OF SCIENCE

in

Applied Economics

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September, 1978

ACKNOWLEDGEMENTS

I am grateful to my major advisor, Dr. Richard Stroup, for his guidance and support and also to Drs. Terry Anderson, Jon Christianson, Edward Ward, and Steve Stauber for their advice and assistance.

I would like to thank the National Science Foundation for the traineeship which funded a significant portion of this work. I would also like to thank Jack Haffey, Don Gregg, Dick Davenport, and Bill Sherwood of Montana Power Company and Bill Opitz and Frank Buckley of the Montana Public Service Commission for their aid in gathering and interpreting data.

Finally, I also wish to express my gratitude to my wife, Carlene, for her often-needed understanding and to our parents, Joe, Helen, Bob and Lois for their continual support.

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ABSTRACT

This study designs an electricity rate schedule for the residential customer class of the Montana Power Company. The rates are designed to provide correct price signals to a majority of consumers with respect to the long run incremental costs of electrical power while still meeting the revenue constraint set by the Montana Public Service Commission. The rates are determined on the basis of the generation, transmission, and distribution costs of existing and incremental electrical facilities. The incremental generation costs is found to be significantly higher than the cost of existing generation. The tail-block energy charge is based on this higher incremental cost of generation. A lower interior block price based on the weighted cost of existing hydro and thermal generation is used to meet the revenue constraint. The resulting long-run incremental cost (LRIC)-based rate schedule incorporates a two block structure of an inverted type and a fixed customer charge. Implications of adopting LRIC-based pricing in electrical rates are discussed. These may include reduced future electricity consumption and the corresponding need for new power plants, reduced environmental pollution from coal-fired power plants, more awareness of electricity bills and electricity consumption of various appliances, and reduced Montana Power Company financing difficultires.

Chapter 1

PURPOSE AND ORGANIZATION

This chapter presents the problem statements, the objectives and limitations of the study, background information on the problem, and a description of the thesis organization.

Statement of the Problem

There has been an increased concern in past years about the remaining energy resources of the world. Some people feel that these resources are being used too quickly because their prices are lower than the true social costs of their consumption. Electrical power is an appropriate example. If the marginal price of electricity[1] is too low, i.e., if the price of electricity is less than the marginal cost of supplying it, electricity consumers (for example, the residential customers) would be receiving incorrect price signals as to the true cost of extra electrical power. The artifically low tail-block price would result in these electricity customers consuming too much electricity. Furthermore, if electricity demand is increasing, there will be stress on the existing generation, transmission, and distribution of facilities, and a "need" to build new, expensive

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[1] Usually the tail- or final-block price of a typical declining block rate structure. (See Table 13. $0.0188 per kwh represents the tail-block price in this rate structure.)

plants to meet this extra quantity demanded. The result is that the average cost of electricity increases more quickly than if those new plants had not been built. Electricity price increases follow. More environmental pollution results from the increased number of generation plants. A drain on energy resources due to an inadequate emphasis on conservation also results. Large users of electricity, who normally face the lower tail-block prices of a declining block rate schedule, are subsidized by the higher prices that low users are paying. Rate increase hearings occur more frequently because of the over-stimulation of quantity of electricity demanded and the resulting additions to capacity and rate base. And finally, investor disillusionment due to this increased frequency in rate increases and the associated "regulatory lags" makes difficult the financing of proposed additional capacity.

The purpose of this study is to design a long run incremental cost (LRIC) - based rate structure that reduces these problems by giving more nearly correct signals to consumers with respect to the true social cost of consuming an extra kilowatt hour (kwh) of electricity.

Questions to the Answered

The questions to be answered in this study are: (1) what is the incremental cost of electricity to Montana Power Company residential customers, (2) how does the (LRIC)-based tail-block price of electricity to Montana Power Company (MPC) residential customers compare with the current or MPC proposed 1978 tail-block rate, (3) how is a rate structure incorporating LRIC-based pricing formed, and (4) what are some implications of pricing based on LRIC to those of pricing not based on LRIC? In order to answer these questions, this paper will show how the LRIC of electrical power may be estimated, given forecasts of future costs. It will demonstrate how LRIC could enter into the pricing of electricity to residential customers, by deriving a rate structure for Montana residential customers based on LRIC pricing and estimates of future coal-fired generation costs. The study will be limited to an analysis primarily (see p.) of Montana Power Company data and estimates and LRIC pricing of electrical service to MPC residential customers.

General Background Information

In the last few years, the real (vs. nominal) generation cost[2] of electricity has been steadily rising in the Pacific Northwest (see Federal Energy Administration, 1976, pp. 216-217 and Federal Power Commission, 1973, p. XIII). Reasons for this escalation

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[2] The total cost of electrical generation facilities or plant corrected for inflation and not including transmission or distribution facilities.

include the lack of recent technological innovation, recent cost increases due to environmental and safety legislation, more expensive fuels, other inflationary pressures (e.g., labor and construction materials costs), and a new, more expensive "mix" of electrical generation facilities for the Pacific Northwest. This new mix is occurring as lower-cost hydro generation fails to expand since the "best" sites are already used. Therefore, coal-fired and nuclear power plants must provide new power. Montana serves as one example with Colstrip Units 1 and 2 recently activated, the source of fuel being coal. The Oregon Department of Energy in a recent study (1976, pp. 5-6) provided a listing of new generation facilities scheduled for service in the Pacific Northwest (see Table 1). The majority of the proposed plants are nuclear fueled with several coal-fired plants also included in the planned facilities.

Several electricity rate structures and rate level determination methods have been proposed to deal with some of the aforementioned problems brought about by these rising costs and current rate structures (Cohn, 1975). An early proposal suggests the typical block design except that the higher quantity blocks would be priced higher than the lower quantity blocks. This is called an inverted rate structure. A principal argument for inverted rates is that the higher rate for later blocks tends to curtail use for most customers. However, lower prices in initial blocks would mean that

Table 1

NEW GENERATING CAPACITY SCHEDULED FOR SERVICE
1976-77 Through 1988-89
Installation Schedule for Thermal Power Projects

Project	Percent Ownership Private	Public	Unassigned	Type of Fuel[1]	Capability Megawatts	Scheduled Operation Date[2]	Probable Energy Date[3]	Principal Sponsor[4]
Colstrip #2[5]	100	---	---	C	165	July 1976	Aug. 1976	PSPL
Jim Bridger #3	100	---	---	C	500	Oct. 1976	Oct. 1976	PPL
Combustion-Turbine Beaver Combined Cycle (addition)	100	---	---	O/G	168	Nov. 1977	Nov. 1977	PGE
WNP #2	---	100[8]	---	N	1100	July 1979	Sept. 1979	WPPSS
Jim Bridger #4	100	---	---	C	333	Dec. 1979	Dec. 1979	PPL
Colstrip #3[5]	100	---	---	C	490	July 1979	Aug. 1979	PSPL
Boardman Coal (Carty)[7]	82	10	---	C	460	July 1980	Sept. 1989	PGE
Colstrip #4[5]	100	---	---	C	490	July 1989	Aug. 1981	PSPL
WNP #1	---	100[8]	---	N	1250	March 1981	Oct. 1982	WPPSS
Skagit #1	100	---	---	N	1288	Aug. 1983	Aug. 1982	PSPL
WNP #3	30	70[8]	---	N	1240	March 1982	Sept. 1983	WPPSS
WNP #4	---	100	---	N	1250	March 1982	Oct. 1983	WPPSS
WNP #5	10	90[9]	---	N	1240	Sept. 1983	March 1985	WPPSS
Pebble Springs #1	85	15[9]	---	N	1260	July 1985	July 1985	PGE
Skagit #2	100	---	---	N	1288	Aug. 1986	Aug. 1986	PSPL
Pebble Springs #2	85	15[9]	---	N	1260	July 1988	July 1988	PGE

[1]C = Coal, O = Oil, G = Gas, and N = Nuclear

[2]Scheduled Operation Date is the date determined by the sponsoring utility for commercial operation.

Footnotes Continued

[3]Probable Energy Date is the later of the Scheduled Operation Date or the Milestone Date. The Milestone Date is a realistic operation date determined from a standardized schedule reflecting anticipated average planning and construction times.

[4]Abbreviations are: PPL = Pacific Power and Light Company; PGE = Portland General Electric Company; PSPL = Puget Sound Power and Light Company; WPPSS - Washington Public Power Supply System.

[5]Colstrip Units #1 and #2 are rated 330 MW each; one-half of each unit will be used by West Group Area. Colstrip Units #3 and #4 are rated 700 MW each; 70 percent will be used by West Group Area.

[6]Jim Bridger Unit #1 is scheduled outside the hydro-thermal program area. Jim Bridger #4 is rated 500 MW; two-thirds of the unit will be used by West Group Area.

[7]Boardman Coal Unit is rated 500 MW; 8 percent has been sold to Idaho Power Company.

[8]Project capability net-billed to Federal System. WNP #1 project is net-billed to Federal System with 340 MW of capacity of 85 percent load factor contracted to private utilities.

[9]Unassigned portions of Pebble Springs #1 and #2 (15 percent) and WNP #5 (20 percent) were assumed purchased by the public agencies but not allocated to individual systems.

Source: Pacific Northwest Utilities Conference Committee, Long-Range Projection of Power Loads and Resources for Thermal Planning, West Group Area 1976-77 through 1995-96, April 16, 1976.

the low-use customer might never pay enough to cover the customer and fixed charges associated with the service he receives, and failure of one group to pay their associated costs would require the remaining customers to subsidize the favored group. This may violate the requirement that no discrimination among customers similarly situated must be present. Therefore, it is important the the initial block rates, or fixed charges, cover the aforementioned costs.

A proposal for flattened rates calls for an identical rate for each kwh and is designed to eliminate the existing variations among different blocks. Recently, where rates include a fuel-adjustment clause, a good deal of flattening has taken place. Fuel costs have risen substantially, becoming an increasing portion of total cost. Since the fuel component increases equally in each block, the fuel clause automatically moderates the variation in price among the various steps of block rates and among customer classes; the percentage difference between steps becomes less. An argument against this structure is that price has no relationship to cost of service other than energy costs. A variation of the same theme that resolves this problem would be to charge customers different amounts to cover delivery and customer charges, plus identical charges for each unit of energy.

Peak-load pricing is another proposed pricing alternative popular among economists. It is based on the reasoning that rates should reflect the higher costs associated with the rendering of service at peak periods. Particular emphasis has been given to time-of-day pricing so that higher prices would be charged for service rendered during daily peaks. Demands at peak periods cause the installation of additional capacity to meet those peaks. These demands also require operation of all available generation capacity including low-efficiency capacity with higher operating costs. Therefore, higher peak prices encourage the customer to transfer his usage to an off-peak period and help to improve the utility's load factor. However, the degree of economic (i.e., efficiency) justification for peak-load pricing depends on the load curve[3] of the particular utility. A utility with relatively large and short duration peaks may institute cost-related peak-load pricing and may achieve a shift in peak periods and, therefore, net benefits. But if the utility has a long-duration peak it "would have a very different scale of peak-load prices and significant load shifts would be doubtful and of less value" (Cohn, 1975, p. 24). Also, to be carried out with any degree of accuracy, it requires installation of expensive metering equipment to record usage on an hour by hour basis. This would represent substantial increases in residential

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[3]This is a graphical representation that indicates the past or predicted electricity demands in kwhs at various times of the day, month, or year.

class costs. Furthermore, the extent to which a shift in customer usage and an improvement in the utility's load factor occur is not clear and can only be more definitely determined through research and trial. This may result merely in shifting peaks from one period to another, requiring further modifications in the rates.

Another proposed pricing alternative, incremental cost analysis, offers an economic justification for pricing and rate structures. Here, incremental or marginal costs are used as the basis for setting rates. The reasoning is that to the extent possible, rates should be based on the incremental costs of serving additional loads rather than average or embedded (historical) costs which have traditionally been used. In a growing system a customer who conserves electricity reduces the need for new, very expensive power generation. The change in power use changes generating costs more than proportionally since new, more expensive (per kwh) generation capacity must be added to the strained system. For the last few years, both the unit costs of new capacity (cost per kwh) and the fixed charges related to new capacity "have been steadily increasing, and they now substantially exceed the average costs and fixed charges associated with existing capacity" (Cohn, 1975, p. 24). Proponents of incremental cost pricing argue that additional loads on the system lead to the need for new capacity and that rates should reflect the associated higher costs. It is suggested that lower rates based on historical costs do not give proper signals to the customers, and improperly encourage use and discourage conservation because they understate costs. The essential objective behind incremental cost pricing is to achieve a closer relationship between rates and the current cost to the utility of extra service. This can be especially valuable in a period of rapid inflation such as the present. "Under the conventional approach, there is no alternative other than successive rate increases to reflect the effect of increasing average costs and, so long as average costs are less than current costs, rates will not be sufficient to cover current costs" (Cohn, 1975, p. 25). Incremental cost pricing can help the utility's rates catch up with current costs when unit costs exhibit a continually rising trend since rates will no longer be based on lower, historical costs. Also, in a growing system, the average total cost of electricity will be reduced because fewer (more expensive) additions to capacity will be needed.

However, a problem occurs if incremental costs, rather than lower embedded costs, are used as the basis for rates for all kwh's consumed. The utility's return in revenue would be substantially in excess of that which is permissable under existing regulation and would result in "excess earnings" (see p. 85). The excess earnings problem, if dealt with by reducing rates for those customers with the least elasticity of demand, i.e., for those customers who would be least likely to increase their usage because of reduced rates, would then suggest a departure from the cost-of-service principle and can only be rationalized as a method of solving the "excess earnings" problem without encouraging greater use. Also, "it can create inequities, inconsistencies, and very substantial practical problems" (Cohn, 1975, p. 25). The inequity arises in that different rates are provided "for customers similarly situated in all respects except that one is likely to make greater use of the service because of lower costs" (Ibid). Furthermore, it would be inconsistent to price some customers according to incremental cost (because they are responsible for creating peak demands) while, at the same time, providing reduced rates to other customers (who also take peak service) because their demand is thought to be inelastic. The practical problems of implementing this pricing method arise from trying to measure elasticity, defining the class to be favored, and identifying the customers, or groups of customers, who fall within the favored category. Also, even where a certain measure of elasticity may be thought to exist, it is not likely to remain a static situation. "It may well shift from time to time for any particular customer or group of customers where there are changing circumstances such as, for example, changes in the price or availability of alternative sources of energy" (Cohn, 1975, p. 25).

Finally, special rates for the "disadvantaged have been proposed as a pricing alternative to the existing situation. The disadvantaged would include the economically disadvantaged, the elderly, or both. These rates are sometimes referred to as "lifeline rates." An argument for this form of pricing is that at least a minimum amount of electric power should now be regarded as a necessity, and the disadvantaged may not be able to pay for this minimum amount of power. The power should, therefore, be provided at a special, below-cost rate by the utility. However, charging one group of customers less than cost of service would require subsidization by another group through rates that are above the cost of service. Because of the apparent discrimination effects, this is not a proper function of utility rates (see Cohn, 1975, p. 25). Practical problems also exist in attempting to define and identify those to whom the subsidy is to be granted. "The assumptions that the economically disadvantaged use less electric power than others, or that those who use the minimum amount of electric power are the economically disadvantaged, have been demonstrated to be invalid" (Ibid).

If it is determined that special assistance should be given to a particular group to help pay for a minimum quantity of electric power, an alternative way to achieve the objective is through governmental action involving taxation and subsidization, or through the use of energy stamps issued to those eligible for food stamps.

What then is the correct form of pricing to allocate costs of electricity in proportion to the costs imposed on the system?

Important considerations in designing any rate structure include: (1) providing signals and incentives to consumers, and (2) establishing equity considerations between producers (what revenue they are entitled to) and consumers (who should pay those revenues) (see Kahn, 1970, pp. 182-199). Kahn and Zielinski (1976, p. 21) state that "the virtue of a price system is that it requires consumers to pay the respective costs that they impose on society by consuming different services, but it leaves it to them to decide which of those costs are worth bearing and which are not. In the same way, the principle of consumer sovereignty would seem to require that customers not be flatly denied the psychic satisfaction of not having to worry about how many calls they place (whether local or long distance), or how long they talk, but only that those who choose that option be forced to pay the costs that their choice imposes on society."[4] If rates are set equal to marginal cost, the consumer who is deciding whether to make a single purchase of an additional unit will compare what it is worth to him with what it costs society to produce it. A consumer will not purchase additional units of a commodity whose cost of production exceeds the value to him. But so

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[4]This assumes that all markets in the economy are working perfectly, i.e., no distortions present. In reality, this does not hold. The "theory of second best" then becomes relevant. See Layard and Walters (1978).

long as value to him exceeds the cost of producing additional units, he will continue to increase his consumption, thereby increasing his and society's economic welfare (utility). In this sense, the consumer's buying decisions will be based on correct signals. Nevertheless, the concept of the cost of a single additional unit is not applicable here since the Montana Power Company system is currently operating at or near capacity and the industry adds capacity in the form of generating units, transmission lines, and distribution facilities capable of producing or transporting more than one unit (kwh) of output.[5] Therefore, for practical purposes it is better to talk of incremental cost, which refers to discrete blocks of additional production (i.e., per kwh) with associated costs expressed on a unit (i.e., per kwh) basis, and long run (rather than short run) costs of doing so. The electric utility industry is a highly capital-intensive one that is growing at a steady and somewhat rapid rate. The application of marginal cost analysis in this industry would logically take into account the cost of an increment of load or demand that may lead to a capital adjustment (increase). Consequently,

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[5] A marginal cost concept would only be relevant if power plants capable of only one kwh output could be built. However, a 100 megawatt plant in today's world, operating at a 75 percent load factor would produce an annual generation of 657 million kwhs.

the concept of long-run marginal or incremental costs seems an appropriate one for the electric utility industry, since marginal costs and long-run incremental costs (LRIC) are concerned with present and to-be-incurred costs rather than what may be on the books (see Frazier, 1975, pp. 9-10). Therefore, LRIC not only includes the immediate short-run expenses due to service expansion but also the annualized cost (including return and related taxes) of that portion of an additional plant required by service expansion. This implies concern with the average unit cost of the capacity and output which a company can reasonably be expected to add in the next decade, for example. LRIC analysis requires looking at the <u>projected</u> costs of system increments in capacity rather than of <u>imbedded</u> costs (Guth, 1974, pp. 8-9).

Furthermore, economic efficiency will result only when pricing occurs at <u>social</u> marginal costs. This implies that those who use a little less electricity save the equivalent of <u>social</u> savings and, therefore, have a smaller bill than if they had used more electricity at the full cost which would have been forced onto the system by additions to capacity. In the absence of a "stagnant" system, LRIC pricing of electricity could lead to social marginal cost pricing. A stagnant system is present when a significant increase in the tail-block price of electricity, for example to LRIC, would result in the system operating with unused capacity continuously in the future.

In this case LRIC (an average total cost of future power) should give way to short-run marginal cost (SRMC) as the basis of pricing since the extra cost of consumption in this case only consists of the variable costs involved in producing the demanded extra kwhs with the previously unused capacity. Therefore, LRIC and inverted block rates would not be justified. However, if the system is growing, and growth in demand for electricity would still occur even with a price increase similar to the above, then inverted LRIC-based rates would be justified. Consumption would then increase over time but at a lower rate than with the existing declining block pricing schedule. Generation facilities would be operating continuously at or near capacity (assuming purchased power supplies the system until new capacity comes on line and resold power eliminates any excess capacity that may exist). Unnecessary additions to capacity will not be built and the average cost of power would not rise as rapidly in the future. If electricity consumers do not face the true opportunity costs of further expansion, the "true" costs of electricity are hidden and excess demand is continually stimulated because of artificially low prices. This implies less incentive for conservation. Pricing at LRIC may also lead to less regulatory "lag" effects (with respect to revenue) since less financing of extra capacity will be needed.

The existing problem of continued financing (both external and internal) of the electrical utility industry may also be solved with the help of LRIC pricing. Pricing at LRIC may set all rates (or at least tail-block rates) high enough to cover true system costs, so that if and when tail-block quantity demanded increases, net revenues increase at the same time.[6]

Finally, LRIC pricing provides a method of pricing that leads to better information (as far as true social costs of electrical power generation are concerned) for public service commissions and potential intervenors in rate issue cases as well as future potential buyers of electrical equipment, appliances, heating, etc. This better information will lead to more successful planning by utilities, regulatory commissions, and electrical customers.

The above discussion has centered on the efficiency function of prices in designing a rate structure. The other function of price that should be considered is to establish equity considerations between producers and consumers, among consumers within a given customer class, and among customer classes.

The equity considerations of any given rate structure will likely be determined through discussion and debate beween

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[6] This is not true when new customers are hooked up since they also consume inframarginally-priced units. Currently, Montana Power Company does not have data on the percentage of their annual increase in residential kwh consumption due to the hook-up of new customers (telephone conversation with Bill Sherwood, MPC General Office, Butte, Montana, August 2, 1977).

representatives of the producer and consumer groups involved. And as Mann (1977) says these nonefficiency rate criteria will lead to rate structures determined by value of service (measured by elasticity estimates), political pressure, social, and institutional considerations. This thesis then will not attempt to derive an LRIC-based rate structure that maximizes the welfare of all residential electrical customers and the producer, but rather will examine the income distribution effects and some implications of the economically efficient (derived) rate structure.

Organization

Chapter One has introduced the problems involved with increasing generation costs of electricity and current rate schedules and the possible solution to these problems by the application of LRIC-based pricing. A discussion of the literature on public utility pricing of electricity with special concentration on LRIC pricing is contained in Chapter 2. Chapter 3 describes the data sources, the data, and application of the data to LRIC pricing, while Chapter 4 summarizes the results of the LRIC pricing application and discusses implications of the adoption of LRIC pricing in electricity rates. The appendices provide a glossary of terms used in the study, a description of the data used, a listing of relevant conversion factors.

Chapter 2

REVIEW OF LITERATURE

Recent literature on marginal and incremental cost pricing of electricity has essentially addressed three questions. First, what goals should public utility regulators have in mind? Second, what form of pricing is considered economically optimal? And finally, what problems exist with implementing marginal cost or incremental cost pricing? This chapter will review some of this literature. Of special concern will be the problems and criticisms associated with implementing marginal cost or incremental cost pricing of electrical service. The correct definition of marginal or incremental cost and an appropriate method of calculation for each are two current issues. Furthermore, rate design problems involving excess revenue or cost distribution within customer classes may arise.

The Goals of Public Utility Pricing

Much of the recent literature in the form of rate-hearing proceedings between electric utilities and public service commissions involves interpreting and attaching priorities to the various goals that utility personnel and regulators consider when determining the price structure for electrical service. The goals that each group has in mind may differ simply because of the interests that are represented by each--the utility strives to maximize profit and growth whereas the regulatory agency is charged with protecting the consumer. Also, the priorities set among the various goals depend very much on the viewpoint of the people involved. For example, an economist may consider economic efficiency of pricing, i.e., marginal cost pricing, to be more important than collecting a certain level of revenue, an objective a utility representative might consider most critical.

Bonbright (1969) and Cohn (1975) essentially agree upon the major goals of regulatory pricing. These include: (1) granting (and restricting) the utilities to a fair rate of return based on costs of rendition and value of service, (2) offering consumers the choice of whatever types and amounts of service they are willing and able to pay for, (3) promoting the public interest, i.e., no harsh inequities or undue discrimination, (4) achieving an optimal allocation of resources between utility service and alternative goods and services, i.e, economic efficiency, (5) maintaining corporate credit and adequate services, (6) insuring rate level and revenue stability, and (7) providing a simple, understandable, publicly acceptable, and feasible application. As one example, there has been an increasing concern directed toward implementing prices and rate structures that improve the utility's load factor and minimize idle capacity.[7]

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[7]See Turvey and Anderson (1977), Mann (1977), Morton (1976), and Cicchetti and Jurewitz (1975).

Other possible objectives for rates and rate structures that are sometimes mentioned include conservation and easing the financial burden on the poor, who are usually assumed to be low users of electricity /see Francfort and Woo (1977)/. However, Mann (1977) and other economists state that incorporating these two latter objectives into rate structures as primary goals may introduce distortions in the form of inequities and subsidization between customer classes. Therefore, even though the objectives may be important, they might be accomplished best by some nonpricing method, e.g., tax deductions for energy conservation home improvements, fuel stamps similar to food stamps, etc. This paper will attempt to incorporate all of the above goals to some degree.

The Economically Optimal Method of Pricing

There are various ways to price electrical service. The legal basis of regulation requires that the price of a unit of electricity be equal to the cost of that unit plus some allowed mark-up. From this point, the method of setting prices becomes more complex. What goal or goals are most desired is a relevant question since certain goals are often conflicting. Also, there are many differerent from of cost, e.g., fixed, variable, average, marginal, short run, long run, on which to base prices. Which of these does one choose?

This question is more easily answered when one of the major roles of electricity prices is considered--namely, that of signaling consumers what it is really worth to conserve a unit of electricity, or equivalently, what is the true cost of consuming an extra unit of electricity.

Many empirical studies have shown that the price of electricity does have a significant effect on the amount consumed. Taylor (1976) reviewed several of these and indicated that the long-run adjustment to a 10 percent increase in price will be approximately a 10 percent decrease in electricity consumption. The short-run response to a similar price increase is probably close to a two percent decrease in consumption (Taylor, 1976). Therefore, if electricity consumers receive the correct signals through the price of that service, then they will be able (and find it to their best interest) to adjust their electricity consumption in the short run and, over time, their capital investments in appliances and energy-saving equipment, and the type of building in which they reside. This will prevent stimulation of demand for electricity due to an artifically low price. As a result, fewer generation, transmission, and distribution facilities will have to be built and, therefore, the average cost of electricity to the consumer will be kept down.[8] But what price

[8] This assumes that an increasing cost situation is present, i.e., rising average cost of electricity.

should be set so that these correct signals are generated? Bonbright (1969) and Kahn (1970) state, if consumers are to make the right decisions, the prices of desired goods or services must reflect their respective opportunity costs--the resources that must be given up by society to produce that good. They point out that this opportunity cost of producing and supplying electricity is the marginal cost to the utility of producing and supplying electricity is the marginal production cost to the utility of producing more or less electricity. Where marginal production capacity is available, marginal cost is the cost of an additional kwh. But where marginal production capacity is not available, it is the curtailment cost (the savings to the system of supplying one less kwh). Baumol (Trebing, 1971) and Kahn further state that the historically popular full or average cost pricing (rather than pricing based on reproduction costs) does not constitute economically efficient pricing and as a result provides the customer with incorrect signals as to the true cost of consuming an extra kwh of electricity. Marginal cost pricing also has the advantage over full or average cost pricing in that it takes account of stress or capacity problems by charging for the value of that service at the pertinent time. Trebing (1971) adds: "Although incremental costs[9] are by no means easy to estimate and in practice

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[9] A form of marginal costs. (See p. 25.)

one should not expect more than good approximations to their magnitude, at least their definition is unambiguous" (p. 145).

If marginal costs are to be used for pricing, one must decide whether short-run or long-run marginal costs should be used, how to define the ones chosen, how long the short and long runs are, and how big is the marginal increment in supply. Kahn (1970) makes the case that what belongs in marginal cost and what marginal costs should be reflected in price should be determined by causal responsibility. This implies that all consumers desiring more units of output should be made to bear the additional costs imposed on the economy by the provision of those extra units. Setting price equal to short-run marginal cost (SRMC) reflects the social opportunity of cost of making available the additional unit that buyers are at any time trying to decide whether to purchase. However, because of the instability of rates based on SRMC as well as other reasons, Kahn says that it is usually not feasible or desirable to use SRMC as a basis for rates. Both Bonbright (1969) and Kahn suggest that there is a need for a relatively stable and continuous trend of rates that are based on long-run rather than short-run costs. However, like SRMC, LRMC also has limitations in its use for cost-based pricing. Trocel (1947) and Morton (1976) state, LRMC's are usually indeterminate because of the lack of cost information for numberous scales of plant.

Although these problems with applying marginal cost pricing are significant, there is a way to escape some of the difficulties.

Economists such as Kahn (1970), Cichetti (Berlin, Cicchetti, and Gillen, 1974), and Morton (1976) have suggested the concept of long run incremental cost (LRIC). Incremental cost is defined as the average additional cost of a finite and possibly large change in production or output. The LRIC of producing a given increment of electrical power is then the total additional unit cost, including return on capital, that will be incurred to produce the total stated output in some defined period of time, e.g., the next few years. The size of the increment in supply determines the level of incremental cost per unit. The larger the increment under consideration, the more costs become variable.

LRIC pricing has several desirable attributes. First, it forces power users to pay the full social cost of their consumption (is theoretically efficient) and thus provides an incentive for conversation practices while allowing extra consumption of electricity which might seem to be excessive but which users are willing to pay for. Those who consume the most electricity in times of excessive demand will be charged considerably more than the ordinary low user. This may lead to less consumption during peak hours when most of the energy-intensive appliances operate, e.g., air conditioners, baseboard heaters, etc. LRIC pricing achieves an efficient use of resources since no one is paying less for electricity than it costs at the margin to supply it. Compared to current rate procedures, it more properly regulates consumer demand so that less new plant capacity will be needed. The section below shows how LRIC-based rates might be implemented.

Implementation of LRIC-Based Rates

To base electrical rates on LRIC, one must first examine how the LRIC of electrical power is calculated. An initial step is to determine the quantity of marginal or incremental output for which LRIC is determined. Morton (1976) points out that the relevant time period and size of the incremental output used are a matter of judgment and can be defined in various ways. The expected increase in output for next year, the next 2, 3, 4, 5, or 10 years, might constitute the "planning horizon" for building of additional plant. Morton and Kahn (1970) say that one must deal first with some specific change in demand for electricity and then with the corresponding change in capacity needed to meet that increased demand. Baumol (Trebing, 1971) claims that in a real pricing problem or application, economists deal with the "intermediate" long run instead of the pure and unusable concept of the theoretical long run. He defines the "intermediate" long run as the <u>relevant</u> long run in the sense that it includes capital costs associated with the exapansion in output under examination and takes into account cost consequences as far into the future as can be foreseen. Frazier (1975) similarly describes the long run as a period long enough so that the producer can modify his stock of capital equipment to meet the demand in the future in an optimal way. Kahn (1970) feels that 10 and 20 year planning horizons for electric companies are not taken seriously and that five years is more of a standard in the industry.

The next step in calculating LRIC-based rates is to determine what cost components to include in LRIC. The examined literature pertaining to the implementation of LRIC indicates that economists and utility professionals are basically in agreement as to the general cost components of LRIC. Baumol (Trebing, 1971), Berling, Cicchetti, and Gillen (1975), Bonbright (1969), Coyle (1974), Frazier (1975), Joskow (Cicchetti and Jurewitz, 1975), Kahn (1970), Morton (1976), Phillips (1969), Turvey (1968), and Weston and Bingham (1972) essentially say that the components of LRIC include administrative and other overhead costs, including distribution or customer cost, capacity costs, and energy (fuel) and related costs. Proceeding from general to specific, however, the authors differ with respect to the degree of specificity involved. Phillips (1969) describes LRIC as including a charge for a portion of the new common plant required, the required return on that portion of common plant, a portion of any increase in overhead, and a portion of investment required to meet the company's future growth.

Kahn (1970) states that LRIC pricing should be in accord with the average of future costs of capital over the planning period. Capital cost components would include a depreciation charge, a current cost of equity capital, and an actual, historic cost of debt capital. He says the gross cost of capital should include charges for interest, profits, income taxes, and property taxes. Further, depreciation, taxes, and return are to be calculated as a dollar amount per person.

In estimating LRIC, Baumol (Trebing, 1971) would consider the situation at any point in time where all current plant and equipment are given. He then recommends estimating the prospective trends in demand for a particular service and the associated operating and capital costs now and in the future. Suppose a reduction in price of the service leads to some increment (increase) in its current and future quantity demanded. Also, suppose that one could estimate the corresponding changes in present and future operating and capital costs. The difference between the present values of these two cost streams--between the anticipated current and future costs before and after the quantity increase--is the relevant basis for the incremental cost corresponding to the change in output (brought about by the change in price).

Frazier (1975) separates the LRIC calculation procedure into two parts. First, he derives the capital cost portion of LRIC, taking into account planned generation, transmission, and distribution facilities, reserve capacity over and above the actual increase in anticipated load or demand, and power pooling and purchased power agreements, existing and planned. Once the capital costs per kw are estimated for the various facilities above, it is necessary to annualize these costs in order to determine overall unit costs per kw. To this is added an appropriate allowance for income tax and other taxes and for the depreciation taken annually. Finally, added to this are the operation expenses that arise because of maintaining accounts, meters, etc. This then gives a cost per kw. The second step in calculating LRIC is to derive the energy-related costs of LRIC. Fuel is the principal cost item that varies directly with the amount of energy sold. To this base fuel cost must be added operating and maintenance expenses which vary with production to arrive at a total cost per kwh (after dividing total costs by net generation of the production plant).

A similar analysis applies the current cost of capital to the incremental cost of plant divided by the annual net generation of the plant in kwh. To this figure must be added the variable operation and maintenance costs per kwh and fuel costs per kwh of incremental plant operation to obtain the LRIC price per kwh of electricity sold (See Morton, 1976).

A "weighted" cost of capital must be used in these calculations because investors perceive different risks in various securities and, therefore, there are different costs associated with these securities (Weston, 1972). The cost of capital to a firm then should be a weighted average of the costs associated with the various funds it uses (debt, preferred stock, and equity).

Coyle (1974) provides a more explicit method for calculating LRIC than any of the previous authors. The reason for this is that his work involves an actual application of the LRIC principle to utility data and forecast estimates. He first calculates an incremental plant production cost of electrical power. Through an allocation method that separates total transmission and distribution expenses and investment into portions that each customer class is considered responsible for, the corresponding incremental costs are determined by dividing by an estimate of total kwh consumption of the customer class of interest for the "test year," i.e., first year of new LRIC rates.[10]

This assumes that the incremental transmission and distribution costs are approximately the same as the historic ones. Otherwise, forecast figures should be used. Added to these figures would be a charge for income and other taxes, franchise fees, and anticipated

[10]The selection of an appropriate allocation method is currently an issue because of the existence of "unallocable" joint costs.

fuel adjustments allocated to the customer class of interest.

Although he does not discuss incremental cost pricing, a lengthy theoretical discussion on how to apply marginal cost pricing to electrical rates is provided by Joskow (Cicchetti and Jurewitz, 1975). Because of possible data limitations and the theory involved, his procedure may be rather difficult to apply in reality. However, he does suggest some interesting things not previously discussed in the literature reviewed. For example, he states that marginal transmission capital costs can be estimated by using the five-year capital budget figures for transmission facilities (in present dollars) and the projected increase in peak power demand over that period. This assumes no excess capacity with current peak loads. He also suggests a statistical cost analysis to examine how much annual operating and maintenance expenses change as system peak capacity changes. This would then lead to an estimate of the corresponding incremental operation and maintenance expenses.

Once the cost components of LRIC are determined, the final procedure is to implement a rate structure that incorporates LRIC, minimizes efficiency distortions, and meets equity constraints. For example, to avoid the vast amount of litigation over public utility rates, Joskow feels that various inflation adjustment mechanisms should be included in rate structures. He also says that if the revenue constraint is not met (either too large or too small a revenue is realized), small adjustments should be made by increasing or decreasing the customer charge to each customer class so that the profit constraint is met. Where large adjustments are necessary, he recommends that in addition to adjusting customer charges, rates also should be adjusted from marginal or incremental costs with the largest adjustment occurring in the least elastic demand categories, e.g., low user in the residential class.[11]

Finally, he stresses that the "lumped sum" (fixed) customer charge must be chosen small enough so that it does not distort consumer decisions in choosing among energy sources.

Besides the many authors who advocate marginal cost pricing and offer suggestions and methodology for its implementation, there also are many who believe that marginal cost pricing has limitations. Turvey (1968) states that marginal cost pricing in electricity will cause decisions by electricity consumers to conform to the national interest only if certain conditions (involving consumer rationality, perfect information, distribution of wealth, and non-existence of externalities) hold. If these conditions are not fulfilled (which is usually the case in the real world), then the problem is one of

[11] Currently, this procedure is legal in Montana (telephone conversation with Bill Optiz, Montana Public Service Commission, July 15, 1977).

sub-optimization or second best. Therefore, it is possible that marginal cost pricing of electricity could lead to an inferior condition relative to the former setting that involved non-marginal cost pricing. However, Cudahy (1976) points out that second-best considerations may not invalidate marginal cost theories. He says that the burden is on those objecting to show how, when, and where and to what specific degree second-best considerations affect the analysis. Sherry (1977) attacks marginal cost pricing by saying that there is no agreed upon method of marginal cost calculation and that the procedure depends on allocating "non-allocable" joint costs. In addition, he feels that "too much government" is needed for its application. Another criticism is that the availability and reliability of data on customer elasticities and estimates of future electricity consumption and costs may be questionable. Furthermore, adjusting revenue excess by the inverse elasticity rule may be worthless if the wrong elasticity is used. In other words, do consumers respond to the change in average price, marginal price, total bill, or average bill? (See Taylor, 1976.) Many utility officials also feel that extensive electrical load research as well as other data would be needed and claim the theory is too complex for application. Mann (1977) states that rates are designed to satisfy multiple criteria and that compromising must occur among these often conflicting criteria. This implies that pure marginal cost pricing is unrealistic.

For example, because of the recent and probably current situation of increasing costs with respect to electrical plant, basing all rates on marginal costs would probably lead to a revenue excess above that allowed by law. Therefore, lower rates for non-tail-block units of electricity have been suggested. This implies an inverted block rate structure. This form of rate structure has also received its own special criticisms. Some utility officials claim that this form of rate structure could require other customers to pay inordinate rates to subsidize the low user (who often is not a poor person). However, this same subsidization may currently exist in decreasing block rates, but with the low user subsidizing the large user. Another criticism is that if large users gave the utility substantial revenues, this form of rate structure might lead to the utility shifting the cost burden to other customer classes (in the form of higher rates) or absorbing the loss itself. This would weaken its financial conditions and ability to serve. Finally, a "volatile revenue" problem may also be introduced by an inverted rate structure. This occurs because a variance in actual kwh consumption levels for a given customer, or group of customers, from estimated levels results in a larger revenue excess or deficiency than under a declining block rate structure. It results to the extent that the change in kwh consumption (from estimated values) arises in the tail block where more revenue per kwh is generated with the inverted structure.

In summary, marginal cost pricing of electrical service in the form of a long run incremental cost-based pricing structure shows promise, but also limitations. Turvey and Anderson (1977) indicate some of these when they suggest adjusting elements in the economically "ideal" tariff (that based on marginal or incremental cost) in order to meet finance, fairness, and acceptability with respect to the revenue requirement (and constraint) as well as equity, social, and political considerations.

Chapter 3

PROCEDURE AND ANALYSIS

This chapter describes an application of LRIC- based pricing theory to cost data and projections of electrical power generation, transmission, and distribution in the Montana Power Company system. The analysis is limited to the design of a residential class rate schedule. A sensitivity analysis is included to examine the possible problem of volatile revenue under an inverted rate structure.

Sources of Data

The majority of data were obtained from a computer printout titled The Montana Power Company Electric Utility Cost of Service Study for the Test Year Ending 12-31-77, Proposed Rates and OC Minus DR RB, produced by EBASCO Services Incorporated, a New York consulting firm. This contains estimates for the 1977 test year on rate base, operating expenses, and expected revenues allocated to each of the customer classes. It is based on a proposed rate schedule for each customer category and was done to provide cost information to be used in a recent rate case conducted by the Montana Public Service Commission (PSC). The data for the study were provided by Montana Power Company (MPC) to EBASCO who then generated the test year estimated.

The estimates used and the assumptions that were made in deriving unlisted estimates are given in Appendix B of this paper.

A second source of data was The Annual Report of the Montana Power Company to the Federal Power Commission for the years ending December 31, 1975 and December 31, 1976. This report examines major financial and physical facets of the electric-utility portion of MPC for the given year's operation. The accounts provided by MPC must conform to the accounting requirements of the Federal Power Commission (FPC) for purposes of complying with federal laws which give the FPC jurisdiction over licensed projects and the transmission and sale of power in interstate commerce. Many of the estimates in the ERASCO study were "total" figures. However, the breakdown of this total into various components was of more interest. The FPC report was used to provide insight for a suitable breakdown procedure. Again, the estimates used and the assumptions that were made in deriving further estimates are given in Appendix B.

To provide estimates for the Colstrip 3 and 4 capital and operation costs, a study prepared by the Energy Planning Program of the Oregon Department of Energy entitled Future Energy Options for Oregon, Appendix IV, Future Electricity Prices in Oregon: A Preliminary Analysis was used. This study provides estimates of operation and maintenance, fuel, and capital expenses for generation plants serving Oregon, as well as changes in the real price of electricity for future years and the northwest region of the United States.

Colstrip 3 and 4 cost estimates and inflation rates to convert 1976 cost figures to 1977 values were supplied by this source. Another data source used exclusively for estimates pertaining to Colstrip 3 and 4 capacity and anticipated output was a letter and enclosures from D. T. Berube, Assistant Chief Engineer, MPC to Gay Lamb, The Mitre Corporation, June 29, 1976. Again, the estimates used and the assumptions made in deriving further estimates from these sources are explicitly stated in Appendix B.

Finally, there were many situations where the desired estimates were not available or where an interpretation of figures or procedure was needed. These were provided by conversations and correspondence with Jack Haffey, Don Gregg, Dick Davenport, and Bill Sherwood of the Montana Power Company and Bill Opitz and Frank Buckley of the Montana Public Service Commission. Notes on these conversations are given in Appendix B for the particular topic of interest.

Data Organization and Interpretation

As previously stated, the data used in the analysis are provided in Appendix B according to the source used. In the analysis in this chapter and the next, reference to the data is by page number, numeral and letter (e.g. see p. 106, 3d of Appendix B). The assumptions made and sources used for each derived estimate are also listed under the appropriate subdivision in Appendix B. Load factor, number of units in the generating system, size of each unit, and geographic location are all relevant to estimating costs. The "best" estimates would then probably originate from an analysis by an outside (unbiased) consulting group using accurate company data, estimates and accounting methods acceptable to the Montana Public Service Commission. This ideal data source normally does not exist, so that one must accept the available data or estimates with a caveat in mind.

Analysis

The purpose in this section is to design an electricity rate structure for the Montana Power Company residential class. The rate structure is based on LRIC and is compared to an MPC proposed 1978 residential rate structure.[12] Items of comparison will include economic efficiency (i.e., private marginal cost equals social marginal cost) and volatility of revenue as a result of an inaccurate estimate of future kwh consumption of the residential class.

Specifically, the rate structure will be designed to face as many residential customers as possible with an LRIC-based price at the margin, yet still meet the revenue constraint and requirement set

[12]From a telephone conversation with Jack Haffey, Rate Department, Montana Power Company General Office, July 22, 1977.

by the PSC. This means that the tail-block price (assuming more than one block exists in the rate structure) should reflect the LRIC of electrical power for economic efficiency purposes (i.e., so that the correct signals regarding the value of conserving extra kwhs are given to these tail-block electricity consumers). The interior block prices will probably have to be made lower than the tail-block LRIC price since pricing all kwhs at LRIC would probably result in excess revenue.[13] Therefore (currently), a typical LRIC-based rate structure is an "inverted" or increasing block structure with most of the anticipated residential electricity customers facing the higher tail-block price as their marginal price. The interior block prices are found by simply adjusting the interior block price downward until the revenue constraint is reached. One possible price derivation is based on:

(1) the premise that electricity from existing hydro generation plants is cheaper than that from existing thermal plants which in turn is cheaper than that from incremental thermal or nuclear plants, and

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[13] Ideally, a single (LRIC-based) block rate structure would be desirable since all customers would face an LRIC-based rate as their marginal price. However, incremental costs of electrical power are greater than existing or historical costs of electrical power, on which the revenue constraint is based. See Table 2 and page 84.

(2) the arbitrary judgment that everyone should share equally in access to the low cost of power from these sources according to the respective proportions of total kwh output available from existing hydro and thermal general facilities. This approach is used in the following analysis.

The general procedure is to derive estimates of incremental thermal and existing hydro and thermal generation, transmission, and distribution costs per kwh and per customer allocated in the MPC residential class. These then are used to obtain estimates of the long run incremental cost of delivered thermal power, the cost of delivered existing hydro power, and the cost of delivered existing thermal power. These three costs are the energy and demand charges of the tail and interior blocks respectively. The LRIC-priced tail block starts at the first kwh in excess of estimated average residential customer use. The lengths of the two interior blocks are determined by apportioning the estimated average residential customer use according to the existing hydro and thermal kwh generation available. The customer charge, that portion of total costs not considered an energy or demand related cost, is also included in the rate structure. Once the rate structure is determined, it is checked to insure the revenue requirement is met and that the LRIC tail-block price acts as a marginal price for a majority of customers. If this is not the case, the rate structure is adjusted so that these two constraints are met.

The first step in this analysis involves calculating the generation cost of electrical power from existing sources. The procedure for finding the generation cost of power from the company's hydro plants is as follows. An estimate for the net hydro plant rate base for the 1977 test year[14] was found from analysis of the EBASCO study. Using a desired (from the Montana Power Company point of view) rate of return on rate base allocated to the residential customer class of 8.45 percent (p. 103, 3b), a test year annual return on capital expense associated with hydro plant investment was found to be $5,394,431 (i.e., 8.45 percent x $63,839,421). To determine total costs, figures for estimated test year operation and maintenance and depreciation expenses must be added to the above figure for annual return. These are $3,117,872 and $1,149,110 respectively (p. 104, 3c). Dividing the sum of these expenses (i.e., $5,394,431 plus $3,117,872 plus $1,149,110) by the estimated generation from the company's own hydro capacity in the test year, 3,741,731 Mwh (p. 98, 1a) results in an estimated test year cost of hydro power geneation of $0.00258/kwh or 2.58 mills/kwh. This is the calculated cost of

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[14]A "test year" is considered to be a representative year with respect to median water conditions and plant operation and is intended to provide a best estimate of average conditions over the next few years for which the proposed rates will be in effect.

power as it leaves the hydro generation plant, and so transmission and distribution losses are ignored for the present time. Similarly, an estimated test year cost of existing thermal power generation was found to be $0.00933/kwh (p. 105, 3d).

The same procedure was used to estimate the cost of incremental (thermal) power generation. The cost of incremental power was assumed to be represented by estimated costs of Colstrip Units 3 and 4 as given in the Oregon Department of Energy study mentioned earlier in this chapter. This figure is $0.02016/kwh or 20.16 mills (p.100, 2b) with approximate output being 2,759,400 Mwh (p.100, 2a).

Other sources of power estimated for the test year include 525,502 Mwh of purchased power from hydro sources at an anticipated cost to the MPC system of $0.00340/kwh and 831,546 Mwh of purchased power from thermal and nuclear sources at an anticipated cost of $0.00470 (p. 98, 1b).

In addition, electrical power is taken out of the system either directly through a net effect of anticipated interchanged and wheeled power[15] from hydro sources, or indirectly through transmission and distribution losses. Test year estimates for interchange and wheeled

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[15]Interchanged power is electrical power delivered to other utilities conditional on a returned amount of power at some other time. Wheeled power is electrical power delivered to other utilities and not contingent on a reciprocal deliverance of power at a future time.

power from hydro sources withdrawn from the MPC system are 86,658 Mwh and 866,784 Mwh respectively (pp. 98-99, 1c,e). An estimated charge rather than credit to MPC (because of previous contractual agreements) in addition to the delivered interchange power resulted in an "effective" cost of that power of \$0.0083/kwh (p. 98, 1c). No credit (or charge) was estimated for the wheeled power (p. 100, 1e). Estimated losses due to transmission and distribution include: (1) 331,387 Mwh from hydro sources at a cost of \$0.00271/kwh, (2) 421,589 Mwh from existing thermal sources at a cost of \$0.00842/kwh, and (3) 275,940 Mwh from incremental thermal power (in first year of plant operation but not in 1977 test year) at a cost of \$0.02016/ kwh (pp. 99, 1f).

From the above figures, Table 2, Power Available for Sale and Resale by Montana Power Company, can be formed.

The initial interior block rate will be based on the estimated test year weighted average production cost of hydro power ($\overline{P}_H$) where

$$\overline{P}_H = \frac{P_H H + P_{HP} H_P + P_{HI}|H_I| + P_{HW}|H_W| + P_{LH}|L_H}{H + H_P + H_I + H_W + L_H} \quad \text{mills/kwh}$$

$\overline{P}_H$ is found to be \$0.00416/kwh. The reason the initial block will be based on this rate is again one of equity. Power from existing hydro generation has a lower cost than power from either existing thermal or incremental thermal generating plants. Therefore, it would seem

Table 2

Power Available for Sale and Resale by Montana Power Company

Sources	Estimated Cost/kwh to MPC	Estimated Production (Mwh)
In 1977 test year:		
Company hydro	P_H = \$0.00258	H = 3,741,731
Purchased power (hydro)	P_{HP} = 0.00340	H_P = 525,502
Interchanged power (hydro)	P_{HI} = 0.00083	H_I = (86,658)
Wheeled power (hydro)	P_{HW} = -	H_W = (866,784
Hydro transmission and distribution losses	P_{LH} = 0.00271	L_H = (331,387
Existing thermal	P_T = 0.00933	T = 3,384,425
Purchased thermal and nuclear	P_{TP} = 0.00470	T_P = 831,548
Existing thermal transmission and distribution losses	P_{LT} = 0.00842	L_T = (421,589)
In a hypothetical future year:		
Incremental thermal	P_I = 0.02016	I = 2,759,400
Incremental transmission and distribution losses	P_{LI} = 0.02016	L_I = 275,940

reasonable (although arbitrary) to say that all Montana customers should have the benefit of consuming a certain portion of their total kwh consumption at a hydro-based price per kwh. This price is reflected in the first block rather than later blocks so that all electricity customers (even the very low user) can benefit from the "cheap" hydro power available. To obtain the complete energy charge for the first block, a charge for transmission, distribution, and general expenses and return on investment in these same plant categories (allocated to the residential class) must also be included. From information on estimated test year transmission, distribution, and general expenses allocated to the residential class and an estimate of total residential kwh consumption for the test year, a charge of $0.01050/kwh was determined (pp. 101, 3a). Similarly, an estimated test year charge for return on "allocated" transmission, distribution, and general plant investment was found to be $0.00574/kwh (p.103, 3b). These calculations assume that hydro generation plants use the same transmission, distribution, and general plant as existing thermal generation plants do. Also, the distribution and general portions of the two preceding charges do not include those expenses and investments directly related to customer charges for residential customers. Introducing transmission, distribution, and general expenses and return on investment in those same plant categories into the energy charge (i.e. $ per kwh) implies the assumption that reducing power consumption reduces the operation and maintenance expenses of maintaining a peaked (assume a growing system which is operating at or near peak capacity) transmission and distribution system and also reduces the need for further investment in these facilities since less strain is placed on the existing facilities in the form of system peak capacity. Therefore, the demand portion (assuming a division of a particular cost item can be made into a demand, energy, and customer portion) of the above expenses and plant investment is included in the energy charge. (Note that this same pricing philosophy has already been applied in calculating the hydro generation cost of electrical power.) The total energy (and demand) charge for the first interior block is then $0.02040/kwh (i.e., $0.00416 plus $0.01050 plus $0.00574).

The customer charge is separate from the energy charge of the first block (and all other blocks) since there will probably be some very low-use customers who will actually be pricing kwh at the margin (i.e. they will be consuming less than the maximum number of first-block-priced kwhs per month) and may attempt to reduce their customer charge by consuming less. This would be an unfavorable situation since the costs related to the customer charge are probably the same to the company for either a 250, 300, or 800 kwh/month residential customer and, therefore, should not vary with energy consumption. For this reason, the customer charge should be levied on a lump-sum-per-customer-per-month basis. The minimum would probably include only those charges that would be saved if one less customer existed or, alternatively, those charges necessary to hook-up one more customer. Therefore, a marginal cost concept is implied. This would mean charging for extra costs due to metering, distribution line hookup, service and installation necessary to hook-up, yearly maintenance, monitoring service necessary, and extra customer accounting, billing, and sales. The maximum customer charge would probably include all of the above plus returns on "ghost" investment (that minimum of primary lines, secondary lines, line transformers, and street lighting necessary even with no customers to hook-up future customers easily in the future). The actual customer charge will be found by adjusting the previously mentioned maximum downward so as to meet the revenue constraint yet extend the LRIC block backwards to face a majority of electricity customers with a marginal price equal to LRIC. No upward adjustment of interior block (i.e., non tail-block) prices would result. Some distortion from interior prices being artificially low and electricity consumers not receiving the correct signals would still occur. The estimated residential customer charge for the test year is $4.88/residential customer/month.

The second inframarginal-block price will be based on the estimated test year weighted average production cost of existing thermal power ($\overline{P}_T$) where (using the symbols from Table 2);

$$\overline{P}_T = \frac{P_T T + P_{TP} T_P + P_{LT} |L_T|}{T + T_P + L_T}$$

This estimate is \$0.01029/kwh. Again, the reason this rate is used as a basis for the second block price is one of equity. Power from existing thermal generating plants costs less than power from incremental thermal plants but more than that from existing hydro plants. Since there exists a limited amount of "cheap" hydro electricity available, then the second block rate (for kwhs above the maximum-alloted, lower-priced hydro kwhs per customer) reflects the cost of the higher priced and currently available thermal electricity. High users of electricity would then have to pay a higher rate for extra kwhs above the maximum first block level because of the limited availability of lower-cost hydro power.

To this production cost must be added the same \$0.01050/kwh and \$0.00574/kwh charges as before for transmission, distribution, and general expenses and return on investment in those same plant divisions. The total energy (and demand) charge for the second block is then \$0.02653/kwh.

The tail- or marginal-block price is based on the estimated weighted cost of incremental thermal generation, ($\overline{P}_I$), for economic efficiency reasons as previously mentioned. Using the values in Table 4;

$$\overline{P}_I = \frac{P_I(I + L_I)}{I + L_I}$$

This estimate is $0.02464/kwh. To this estimated production cost must be added charges for incremental transmission, distribution, and general expenses and return on incremental investment in those same plant divisions. It was assumed that these respective charges could be represented by the same $0.01050/k2h and $0.00574/kwh charges as before for (historical) transmission, distribution, and general expenses and return on investment in these same plant divisions (a "reasonable" assumption according to Don Gregg, Montana Power Company Planning Department). The total energy (and demand) charge for the marginal block kwhs is then $0.04088/kwh.

The calculation of the interior block lengths is based again on equity as well as total revenue considerations (so as to insure the revenue constraint and requirement is exactly met with the given projections for consumption). Putting aside the revenue aspect for the moment, an equity consideration might involve incorporating into the rate structure the proportion of inexpensive hydro-generated power relative to total available kwh generation in the system. The calculation proceeds as follows. Estimated hydro generation in the test year purchased power from company plants is 3,741,721 Mwh (p.98, 1a). Estimated test year purchased power from hydro sources if 525,502 Mwh (p. 98, 1b). Power from hydro sources is delivered out of the MPC system through the effect of interchange, wheeled, and resale power estimated in the test year. These figures are 86,659 Mwh, 866,784 Mwh, and 97,832 Mwh respectively (pp. 98-99, 1c, e, d respectively). Therefore, estimated net hydro generated power available in the test year (excluding transmission and distribution losses) is 3,215,959 Mwh (i.e. 3,741,731 plus 525,502 - 86,658 - 866,784 - 97,832 Mwh). Estimated test year thermal generated power (excluding losses) is 3,384,425 Mwh (p. 98, 1a). Total estimated test year generation available to MPC customers (excluding losses) is then 6,600,384 Mwh. The hydro proportion of this total is 48.7 percent. Estimated test year average residential use is 611/kwh/month/customer (p. 101 3a). Therefore, the estimated test year lower-cost hydro portion of average residential use available to each residential customer is 298 kwh/month/customer (i.e. 48.7 percent x 611). This is chosen as the "calculated cutoff" on the first interior block. The cutoff on the second block is determined by the thermal proportion of total generation available (and used) added to this first block cutoff value, or simply 611/kwh/month/customer, the previously mentioned figure for estimated test year average residential use. Any monthly consumption above this figure would be charged to the customer at the LRIC price of $0.04088/kwh.

In summary, the complete residential rate structure (ignoring the total revenue constraint and requirement) is given in Table 3.

Table 3

Proposed Residential Class LRIC-Based Rate Design

Customer Charge = $4.88/meter/month

Monthly Kwh Consumption (kwh)	Energy Charge (per kwh)
0 - 298	$0.02040
299 - 611	0.02653
612 - above	0.04088

To determine whether the revenue constraint (and requirement) would be met with the above prices and block structure, an estimate of total revenue collected under this rate structure must be made given estimates of the projected number of residential customers consuming a particular number of kwh per month. Montana Power Company faces this same problem when proposing a new rate schedule. A compilation of projections involving essentially the above information is provided in the company's "billing reverse accumulation statements". Upon examination of these anticipated purchasing schedules, it was determined that under the above rate schedule total revenue collected would amount to $42,916,646 (p. 107 , 4b). The residential class revenue constraint (and requirement) anticipated if the MPC proposed 1978 rates (see Table 6) are accepted is

$43,756,994 (p.107,4a). Upon comparison of the two preceding figures, it can be seen that a revenue deficiency will result under the proposed LRIC-based rates. Therefore, it is necessary to "adjust" the rate schedule interior block-lengths and/or prices so that: (1) the revenue constraint and requirement is met, and (2) the increase in inframarginal electricity consumption due to artificially low prices is minimized.

The "revised" LRIC-based residental class rate schedule which meets the revenue constraint and requirement (see pp. 107-109, 4c) is given in Table 4. For comparison purposes, the 1977 and proposed 1978 residential class rate schedules are given in Table 5 and Table 6.[16] The previous LRIC-based rate schedule was converted from a 3-block structure to a 2-block structure with a higher first-block energy charge to emphasize economic efficiency under the given revenue and customer charger constraints. This also assures that very low users will pay at least part of the thermal generation costs. Under this rate structure, 63 percent of the total number of residential customers will face an LRIC price as their marginal price. As a result low users will not face a marginal price as low as the previous (artificially-low) first-block price, yet still

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[16]Montana Power Company's 1977 and proposed 1978 residential rate structures given in Tables 5 and 6 are as of August 1, 1977.

benefit (but to a lesser extent) from lower consumption levels and electric bills through the lower interior block price (relative to the LRIC tail-block price).

Table 4

Revised Residential Class LRIC-Based Electricity Rate Design

Customer Charge = $2.23/meter/month

Monthly Kwh Consumption (kwh)	Energy Charge (per kwh)
0 - 310	$0.02412
311 - above	0.04088

Table 5

1977 Residential Class Electricity Rate Schedule

Monthly Service Charge = $1.70/hook-up

Monthly Kwh Consumption (kwh)	Energy Charge (per kwh)
0 - 200	$0.0318
201 - above	0.0160

Source: Montana Power Company, Bozeman, Montana, August 1, 1977.

Table 6

Proposed 1978 Residential Class Electricity Rate Schedule

Monthly Service Charge = $2.26/hook-up

Monthly Kwh Consumption (kwh)	Energy Charge (per kwh)
0 - 20	-
21 - 100	$0.0716
101 - 200	0.0502
201 - above	0.0250

Source: Jack Haffey, Rate Department, Montana Power Company General Office, Butte, Montana, August 1, 1977.

Upon comparison of these rate schedules, it can be seen that the 1977 and MPC proposed 1978 rate schedules are of the declining block rate type, charging less per kwh for higher consumption. Therefore, there is a built-in incentive to consume more electricity and less price-based incentive to conserve electricity as compared to the proposed LRIC-based "inverted" rate schedule in Table 4. Further, the tail-block price in the 1977 and MPC proposed 1978 rate schedules is far less than the LRIC price in the tail-block of the proposed rate schedule in Table 4. This implies that electrical consumers under the 1977 and MPC proposed 1978 rate schedules are not receiving the correct signals since the tail-block price is less than the opportunity cost of consuming an extra kwh of electricity.

One of the major objections to LRIC pricing in current times of increasing generation costs is the problem of "volatile revenue" which may be introduced by an inverted rate structure. This occurs when variation in actual kwh consumption levels from estimated kwh consumption levels results in a larger revenue excess, or deficiency under an inverted rate structure as compared to a declining block rate structure--the reason being that the change in kwh consumption (from estimated values) arises in the tail block, where more revenue is generated per kwh with the inverted structure. This problem is examined through a sensitivity analysis, using high and low estimates for residential test year kwh consumption to find the percentage change in revenue under the MPC proposed 1978 rate schedule and the proposed LRIC-based rate schedule (see pp. 109, 112, 5a, 6). The high and low estimates were 1,312,864 Mwh 1,273,907 Mwh respectively (see p.109 , 5b), while the test year estimate for residential consumption given in the EBASCO study is 1,298,580 Mwh (p. 101, 3a). Assuming that all the extra kwhs (or deficienct kwhs) above (or below) this latter figure are consumed (or conserved) as tail-block kwhs, the percentage change in revenue under both rate schedules is given in Table 7 (p. 111, 5c).

Table 7

Percentage Change in Revenue Assuming the Entire Kwh Difference Involves Only Tail-Block Kwhs

	Under Proposed LRIC-Based Rates (%)	Under MPC Proposed 1978 Rates (%)
If actual consumption climbed to the "high" estimate	1.3	0.8
If actual consumption only reached the "low" estimate	-2.3	-1.4

If we assume instead that all extra kwhs (or deficient kwhs) above (or below) the estimated test year residential consumption are consumed (or conserved) in the first non-zero priced block by new additional (or less) low-use customers, the percentage change in revenue under both rate schedules is given in Table 8 (p. 111, 5c).

Table 8

Percentage Change in Revenue Assuming the Entire Kwh Difference Involves Only First-Block Kwhs

	Under Proposed LRIC-Based Rates (%)	Under MPC Proposed 1978 Rates (%)
If actual consumption climbed to the high estimate	0.8	2.3
If actual consumption only reached the low estimate	-1.4	4.0

The two assumptions made in Tables 7 and 8 pertaining to where the kwh difference in consumption occurs represent the extreme cases. In all probability any increase or decrease in kwh consumption different from the anticipated value would involve kwhs in all blocks and would make the analysis much more difficult yet provide results between the two extremes calculated above.

Chapter 4

SUMMARY, CONCLUSIONS, RECOMMENDATIONS

Summary

Recently, increasing electrical costs have come to the attention of utilities, public service commissions, and economists, as well as the general public. These higher costs have emerged as the result of a combination of factors. Electrical generation and transmission costs have risen rapidly due to the increased cost of environmental control, the lengthening of construction time needed because of the complexity of new plants, and the change in the "mix" of generation facilities (i.e. most new plants are of the thermal and nuclear variety rather than hydro). Also, operation and maintenance costs and fuel costs have risen faster than rates of inflation in past years. Finally, the rate of return on investment granted to utilities has also increased because higher returns were necessary to attract capital for expansion, reflecting higher interest rates in the economy and more uncertainty about utility earnings. As a result of these higher costs, electricity rates have also increased, generating more interest in rates and rate hearings. Economists have found that historical rates lack formal cost-based guidelines. These rates have been instead designed to attract certain classes of business, to meet the revenue constraint (and requirement), and as mentioned in Chapter

2, to promote growth of the utilities (see the discussion of the Averch–Johnson Effect in Averch and Johnson, 1962, pp. 1053-69). Because some of these objectives had the effect of promoting artificially low price signals to electrical customers, a demand for electricity not warranted by the marginal value in use, developed. In addition, many forecast studies ignored the effect of price on electricity consumption and, therefore, predicted high values for anticipated consumption which implied a "need" for more generation facilities than users would, in fact, want to pay for. These factors led to power plants being built to produce electricity costing more than its value to users, who paid average, not incremental prices for the incremental power. Current interest in rates has stimulated attempts to produce better rate designs. Attributes of new forms of rate structure might include: (1) correct price signals given to electricity consumers so as to prevent additions to capacity which produce electricity costing more than its value to users; (2) rates (or at least tail-block rate) incrementally based so as to reflect the cost of new additions to capacity; (3) equity considerations taken into account in designing a rate structure; and (4) rates (or at least tail-block rate) designed for revenue and rate stability.

This study includes the design of a rate schedule for the residential electricity customer class of the Montana Power Company

(MPC), incorporating the above attributes. The sources of data and cost estimates included MPC cost studies, Federal Power Commission publications involving electrical plant data on MPC, an Oregon Department of Energy publication on plant cost estimates and future electricity prices, and conversations and correspondence with MPC and Montana Public Service Commission representatives.

The first step in the analysis involved estimating the generation cost of electrical power from existing and incremental sources. These costs are summarized from Chapter 3 in Table 9. Notice that

Table 9

Estimated Electrical Power Generation Costs in the Montana Power Company System (Ignoring Losses)

Source	Mills/kwh
Test year hydro plants	2.58
Test Year thermal plants	9.33
Incremental thermal plants	20.16

the estimated incremental cost of power generation is more than twice as large as the cost of power from existing thermal plants and almost eight times as large as the cost of power from existing hydro facilities. This had been expected since the existing generation cost involves economical hydro plants and less-expensive thermal plants rather than the anticipated larger incremental costs associated with Colstrip Units 3 and 4. The tail-block energy charge of the proposed rate schedule was found by adding to the incremental production cost estimate, charges for transmission and distribution losses and charges for expenses and return on investment allocated to the residential class as a result of transmission, distribution and general plant operation and investment. These latter charges were converted to a per kwh charge by use of an estimated yest year figure for residential kwh consumption, on the assumption that a decrease in consumption would lead to less investment in these plant categories and, therefore, less expense involved in their operation. A lower initial-block rate was needed to meet the revenue constraint set by the regulating authority. This was designed with both equity (allocating the "cheap" existing hydro and thermal output among the Montana Power Company customers) and efficiency (minimizing an increase in consumption due to artificially low lower prices) in mind. The customer charge, calculated to reflect costs <u>not</u> varying with energy use, was also adjusted within these same considerations.

The proposed LRIC-based rate is given in Table 10. It is the inverted type with the tail or marginal block price reflecting the LRIC of electrical power. It also meets the proposed 1978 revenue constraint and requirement of $43,756,994 (p. 106, 4a). The percentage of residential customers facing an LRIC price at the margin is estimated to be 63 percent. The customer charge seems to be acceptable from both a political and equity viewpoint.[17] The initial block rate is based on the weighted cost of power from existing hydro and thermal sources and provides the low user with lower rates, rather than rewarding extra use with lower tail-block rates. Revenue, with this rate structure may be more volatile than with the existing structure, since MPC anticipates that a significant amount of its growth in residential consumption will originate in tail-block kwh consumption. (However, possible solutions to this problem exist. See pp. 26-29.) One possible reason for this increase in tail-block usage is the anticipated increase in all-electric homes in the MPC system due to concern about future natural gas availability and new home construction costs. Historical data on all-electric homes is given in Table 11.

Table 10

Proposed Residential Class LRIC-Based Electricity Rate Structure
Customer Charge = $2.23/Meter/Month

Monthly Kwh Consumption (kwh)	Energy Charge (per kwh)
0 - 310	$0.02412
311 - above	0.04088

[17] By comparison with the customer charge of the MPC proposed rate schedule which Jack Haffey of the MPC Rate Department indicated was politically acceptable and cost justified.

Table 11

Montana Power Company All-Electric Home Increase Over Previous Year

Year	Increase in Number of All-Electric Homes
1971	186
1972	193
1973	219
1974	614
1975	547
1976	1198
July 18, 1977	More than 1198

Source: Bill Sherwood, Montana Power Company General Office, Butte, Montana.

Conclusions and Recommendations

Assuming the proposed LRIC-based rate structure in Table 10 is adopted, what are some of the implications? For example, what would constitute a simple measure of the value of that adoption to the general public? Given a long-run price elasticity of demand for residential electricity, one can approximate a net decrease in annual residential kwh consumption due to the higher LRIC-based tail-block price (relative to the tail-block price of the MPC proposed 1978 rate schedule). For example, for the year 2000, estimated annual MPC residential customer kwh consumption is 3,969,040 Mwh (p. 112, 6). Even though the average residential bill under both rate schedules is the same, the LRIC-based tail-block price (from Table 10) represents a 63.5 percent increase relative to the MPC proposed 1978 tail-block price (from Table 6). Therefore, assuming a long-run price elasticity of -0.81 (see Taylor, 1976, p. 5), and assuming the fail-block rate is the relevant price, the net decrease (N) in anticipated year 2000 annual residential kwh consumption is (0.81) (63.5 percent) or 51.4 percent. This implies an estimated year 2000 annual residential consumption of 1,928,953 Mwh, i.e., (1-0.514) (3,969,040 Mwh), rather than the previously anticipated 3,969,040 Mwh. Therefore, a 2,040,087 Mwh decrease in estimated kwh consumption is anticipated as a result of LRIC pricing rather than the MPC proposed 1978 rate schedule. (Note that under the proposed LRIC-based rate schedule there will be some increase in kwh consumption for those who face a marginal price equal to the lower first block price, since it is less than the corresponding first block price under the MPC proposed 1978 rate schedule. However, the majority of residential electricity consumers are expected to decrease their consumption as a result of the higher LRIC tail-block price, which is their marginal cost of electricity.) This means that fewer generation facilities will be needed as a result of instituting the LRIC-based rate schedule. For example, using the MPC estimated annual kwh output of Colstrip 3 of 1,379,700 Mwh (p. 100, 2), the adoption of the LRIC-based rate schedule implies that an incremental power plant about 1½ (i.e. 2,040,087 ÷ 1,379,700) times the size of Colstrip 3 (in annual kwh output) would not be needed to supply future electrical demand. Thus, because of the need for less (expensive) incremental plants, the average cost of electricity to the residential consumer in the year 2000 will be reduced. Furthermore, this decreased need for a power plant of approximately 1000 Mw capacity also implies that less environmental pollution from producing electricity will result. For example, Table 12 gives estimated emission levels and water use associated with a typical 1000 Mw coal-fired power plant. These are important considerations because of the possible adverse effects on human and plant life that could result. Oxides of sulfur and nitrogent, trace elements such as mercury, and dust and particulate matter are released in stack gases and become airborne. It has been shown that these emissions act as irritants of the eyes and respiratory system and can contribute to acute and chronic respiratory diseases and lung cancer. In addition to these basis emittants, sulfates can form hundreds of miles away from the power plant and have similar health effects. Acid rain is another by-product that predominantly affects states in the northeastern part of the country because of the effect of existing wind and air currents. A decrease in fish population and reduction in agricultural and forest productivity are possible effects of acid rain. Also, unburned residues, either coal ash, sludge from desulfurization systems or particles trapped by other control systems, contain trace elements such as heavy metals and radionuclides (i.e., radioactive thorium and uranium). These are normally retained in land disposal systems. If these elements leach into drinking water supplies or soils, they can get into food chains and cause toxic effects on humans and animals. The coal combustion process also releases a significant amount of carbon dioxide into the atmosphere (1.8 times that of natural gas combustion) and at elevated levels, this could cause climate modifications (i.e., the Greenhouse effect). In addition, the water supply is extensively taxed in that large amounts of water are needed for cooling. Thermal discharges of this water back into the water supply have adverse effects on local fish life. Finally, air pollution from these plants can also have visibility effects which could negate the esthetic value of the surrounding area (U.S. Dept. of Health, Education, and Welfare, 1978).

Montana Power Company recently announced that in spite of increasing energy conservation campaigns, average MPC residential customer electrical use rose 4.4 percent to 7,308 kwhs during 1977 (Great Falls /Montana/ Tribune, Feb. 21, 1978). The company seems quite concerned about this growth. They view natural gas supplies as

Table 12

Estimated Emission Levels and Water Use Associated with a 1000 Mw Coal-Fired Electricity Generation Plant

Net Capacity: 1000 MW (Net implies in-house power has already been accounted for.)

Annual Load Factor: 0.75

Fuel: Western (Montana) coal

Environmental Controls: Flue Gas Desulfurization and Cooling Towers

Estimated Emittant Levels: SO_2 - 112.32 tons/day

NO_2 - 65.52 ton/day

Dust and Particulate - 9.36 tons/day

Sludge - 1,053.93 tons/day

Net Water Usage: 6700 gallons/minute
(Water is lost mainly as steam in the cooling cycle.)

Source: Minnesota Pollution Control Agency. Draft: Environmental Impact Statement Northern States Power Co.'s Proposed Units 3 and 4, Sherco Steam Electric Station, July 1977.

adequate into the next century and encourage its use in home heating to avoid adding unnecessarily to the firm's peak electrical demands and, therefore, hastening the need to construct new generating plants. The use of the suggested LRIC-based rate structure would encourage use of gas for heat (see Table 12).

Another implication of adopting the proposed LRIC-based rate structure would be its value as a lifeline rate structure. Even though the rate structure was not designed with this purpose in mind, it would feature similar attributes. The basic idea behind a lifeline rate structure is to provide an essential amount of electricity at an affordable price. The lower first-block price in this rate structure would provide such a cost savings for lower and fixed-income electricity customers who were also low users. For example, Table 14 shows typical electricity bills for residential customers of varied usage levels under several alternative rate structures. Notice that the low user of electricity has the smallest bill under the proposed LRIC-based rate structure. Compared to the current 1978 MPC residential rate structure shown in Table 13, the LRIC-based inverted rate structure would save a 250 kwh per month user $2.43 per month. Bills under these two rate structures would become equal for a customer usage of about 406 kwhs per month (see Appendix B, p. 112, 7). After this usage level the current 1978 MPC rate structure would result in the lowest bill. The obvious question is then: What is the monthly kwh use of a typical low-income residential customer? This varies with the customer. For a residential consumer who uses an electric water heater and/or relies on electricity for well pumping, clothes drying and space heating, kwh usage levels will be significantly increased. Table 15 gives typical monthly kwh usage levels for various consumer appliances. Other problems with developing lifeline rates would include avoiding discrimination against low-income families and home owners (relative to apartment dwellers), who are normally larger users of electricity. Also, a lifeline rate may provide benefits to many who aren't needy.

Despite these obvious shortcomings public service commissions and citizen groups are still quite concerned about helping those people who presently find it most difficult financially to pay their utility bills. As an example, the Minnesota Public Service Commission recently directed Norther States Power Co. (NSP) and Minnesota Power and Light Co. (MP&L) "to devise rates that would provide all of its residential customers with an essential amount of electricity at an affordable price" (Hagen, 1978). The Commission was quoted as saying: "We have obligations to the flesh-and-blood people of Minnesota which theory alone will not satisfy." They further said that the upper limit of any lifeline

Table 13

Current 1978 Residential Class Electricity Rate Schedule

Monthly Service Charge = $1.69 per hook-up

Monthly KWH Consumption (kwh)	Energy Charge (per kwh)
0 - 20	-
21 - 100	$0.0538
101 - 200	0.0376
201 - above	0.0188

Source: Montana Power Company, Butte, Montana, May 23, 1978.

Table 14

Typical Electricity Bills for Residential Customers of Varied Usage Levels Under Alternative Rate Structures*

Monthly Kwh Consumption	1977 MPC Rates	MPC Proposed 1978 Rates	Proposed LRIC-Based Rates	Current 1978 MPC Rates
250	8.86	14.258	8.26	10.694
650	15.26	24.258	23.6064	18.214
1500	28.86	45.508	58.3544	34.194
2500	44.86	70.508	99.2344	52.994
5000	84.86	133.008	201.4344	99.994

*See Tables 5, 6, 10, and 13 for corresponding rate structures.

rate should be made not less than 350 kwhs per month for MP&L and 300 kwhs per month for NSP. In addition, in September of 1977, the Colorado Public Utilities Commission ordered the Public Service Company of Colorado to give its low-income elderly or disabled customers a 50 percent discount on the total charge for the first 25,000 cubic feet of natural gas they buy per month from October through April (Hagen, 1978). The decrease in revenue from these customers was subsidized by billing other customers accordingly. The utility identified this low-income segment of customers through the help of the state revenue department, who listed all people who qualified for the state's property tax or rent credit. The commission's order was later extended to nine other smaller utilities in the state.

Nevertheless, to effectively determine the value of the proposed LRIC-based rate structure as a lifeline rate structure, further research is necessary. For example, it would be beneficial to determine the percentage of Montana Power Company's residential customers that would benefit from lower bills under the lifeline rate structure. Comparing this figure to the percentage of total customers considered low-income customers would give some idea of the number of customers deriving benefits that don't really qualify. From these figures and corresponding billing statements one could determine the maximum annual benefit in dollars that could be

Table 15

Average Kwh Usage Levels for Various Consumer Appliances

LAUNDRY	Average Wattage	Average Hours of use Per Month	Average KWH Per Month
Clothes Dryer - Electric.	4,856	17	83
Clothes Dryler - Gas (electric usage cost).	300	17	5
Iron.	1,008	12	12
Washer Automatic.	512	17	9
Washer Non-Automatic.	286	22	6
Water Heater Quick Recovery . . .	4,500	110	500
COOKING AND REFRIGERATION			
Broiler (Counter Top)	1,436	6	8
Electric Fry Pan.	1,196	13	16
Microwave Oven.	1,450	14	20
Range/oven (self cleaning oven add 6 kwh per month)	3,000	41	123
Refrigerator (12 cubic feet). . .	300	250	75
Refrigerator (Frostfree - 12 cubic feet).	330	316	105
Refrigerator-Freezer (Partial frostfree - 14 cubic feet) . .	350	350	123
Refrigerator-Freezer (Side-by-Side-Frostfree - 19 cubic feet).	500	360	180
Freezer (Upright-Frostfree-15 cubic feet)	440	333	147
Freezer (Chest type - 15 cubic feet) (Upright models lose more cold air when the door is open, thus they can use up to 25% more electricity than chest type models.).	341	292	100

Table 15, Continued

KITCHEN	Average Wattage	Average Hours of Use Per Month	Average KWH Per Month
Blender	386	3	1
*Coffee Maker (Standard Percolator Type - 2 pots per day)	900 (45)	9 (300)	20
*Coffee Maker ("New" Drip Type - 2 pots per day).	1,550 (50)	9 (300)	30
Dishwasher.	1,201	25	30
Toaster	1,146	3	3
Crockery Cooker	100	120	12
HOME ENTERTAINMENT			
Radio	71	101	7
Stereo.	109	83	9
Television - Black and White (Tube type, 160 watt).	160	182	29
Television - Black and White (Solid State, 55-watt).	55	182	10
Television - Color (Tube type, 300 watt).	300	183	55
Television - Color (Solid State - 200 watt).	200	183	37
(TV sets with instant-on features, add 20 kwh per month.)			
MISCELLANEOUS			
Blanket	177	69	12
Clock	2	730	1
Vacuum Cleaner.	630	6	4
*Garage Door Opener (controller on continuously).	230 (20)	2(720)	15
Furnace Fan	600	360	216
Humidifier.	120	360	43
Room Air Conditioner (8000 BTU, EER 6)	1150	180	207
Air Conditioner, Central (30,000 BTU, 2½ tons, EER 6)	4285	180	771

*These appliances operate at higher wattages for short periods; lower wattages for continuous amounts of time.

Table 15, Continued

LIGHTS	Average Wattage	Average Hours of Use Per Month	Average KWH Per Month
Five-room house			50
Six-room house.			60
Eight-room house.			80

Source: Northern States Power Co., 1978.

obtained for low-income customers under a lifeline rate and also the amount of subsidization required from larger users. Also, as Table 15 indicates large residential users of electricity, such as rural customers who use much of their electricity in farm operations, would see significant increases in their electricity bills relative to their bills under the current MPC residential rate structure. Consideration of these "apparent" inequities must be made in any policy decision.

In addition to possessing lifeline attributes, the implementation of the proposed LRIC-based rate structure might also introduce other social benefits. For example, Montana Power Company forecasts electricity deficits in Montana beginning in 1981-82 and increasing thereafter if Colstrip units 3 and 4 are not built (Johnson, 1978). This assumes certain climatic and energy supply conditions and a traditional declining block pricing structure. However, adoption of the inverted LRIC-based rate structure would probably lead to less future electricity use and, therefore, less danger of imminent electricity shortages to MPC customers if construction of Colstrip 3 and 4 is delayed or halted. Also, because of the many environmental constraints on nuclear and coal-fired electricity generation, national electricity shortage could become a serious problem under a historically-based future scenario. Transitional technologies such as coal- and oil-fired electricity generation will provide our nation with energy supplies until alternative technologies such as solar energy become further developed and economic. However, pricing energy at an artificially low price that does not reflect the true cost of consuming that energy retards this development of alternative technologies since the economic incentive is not there. Specifically, pricing electricity from coal-fired units below its LRIC of production limits interest and development of environmentally clean and virtually inexhaustible solar electricity generation because of the false disparity between the apparent coal-fired generation cost and the higher solar generation cost. Only when energy prices reflect true social costs of production and consumption will sufficient incentive for alternative technology development be present.[18] This further implies that all electricity customer classes should face these economically correct electricity prices. Although this study was limited to examining LRIC pricing applied to the residential customer class, the principles and ideas should also be directed toward the commercial and industrial electricity customer classes of Montana Power Company. This may meet with substantial opposition from large industrial users since their

[18]The extensive use of solar power, however, can lead to certain problems. This is because those solar units usually depend on a back-up system (the utility) to provide extra electricity on especially cold or hot days. Therefore, even though the system peak may be reduced because of extensive solar power use, the load factor of the utility is worsened.

electricity bills would probably be significantly increased. However, long term effects might also include more development and use of cogeneration, on-site power generation, and district heating. These can not only improve Montana's energy and environmental future but also the nation's.

Implementing LRIC-based rates might also make people (especially large users of electricity) more aware of their electric bills and electricity consumption of various appliances. Table 16 indicates monthly kwh totals and corresponding electric bills for typical electricity consumers. Notice that the small user benefits under the proposed LRIC-based rate structure relative to the current residential rate structure. As previously mentioned, at a consumption level of about 406 kwh per month electricity bills under the two rate structures are equal at $13.62. However, for usage levels above this, larger bills would result under the LRIC-based rate structure. The heavy user of electricity would be especially affected, with his electricity bill nearly doubling at a 2379 kwh per month consumption. In order to reduce their electric bills, consumers could be expected to choose energy efficient appliances, properly insulate their homes, and conservatively consume electricity.[19]

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[19] Studies cited earlier, and summarized in Taylor (1975) indicate that over time a 10 percent price increase leads to about a 10 percent reduction in quantity demanded.

Another benefit of adopting the proposed LRIC-based rate structure would be its value as a transitional rate structure before further rate structure improvements such as peak-load pricing might be introduced. The recent order of the Montana Public Service Commission (Moes, 1978) for Montana Power Company to use a flat-rate tariff structure for the residential class is a step in the right direction but does possess one serious shortcoming. Any given customer pays the same price per unit no matter how much electricity is consumed. Total cost to the customer increases with consumption so there is an incentive to conserve. If the single block price is equal to the long run incremental cost of production, this rate structure can be considered economically efficient since all users face a marginal cost-based price as their per unit charge. However, as will be shown, pricing all kwhs of estimated 1977 consumption at LRIC results in a revenue excess (see p.). Therefore, if a flat rate is still desired, this implies that it must be adjusted downward from LRIC. This leads to electricity customers receiving incorrect signals as to the true cost of electricity, i.e., economic inefficiency. So, as long as a limiting revenue constraint is present, this form of rate structure is inadequate. Adopting the proposed LRIC-based rate structure would improve on this shortcoming and ease the adjustment needed to switch from a traditional declining block rate structure to one incorporating peak-load pricing (as well as LRIC-based rates), which many economists feel is the form of

Table 16

Monthly Kwh Totals and Corresponding Electric Bills for Typical Electricity Consumers

LIGHT USER

	Average Kwh Per Month
LAUNDRY	
Clothes Dryer - Gas (electric usage only) .	5
Washer - Automatic.	9
COOKING AND REFRIGERATION	
Fry Pan	16
Coffee Maker (Percolator Type, 2 pots per day).	20
Toaster	3
Refrigerator (12 cubic feet).	75
HOME ENTERTAINMENT	
Radio	7
Television (Color, Solid State 200 Watt). .	37
MISCELLANEOUS	
Clock	1
Vacuum Cleaner.	4
Lights, 5-room living area.	50
MONTHLY TOTAL.	224
Monthly bill under current 1978 MPC Rate Structure.	$10.20
Monthly bill under proposed LRIC-Based Rate Structure.	$ 7.63

Table 16, Continued

MODERATE USER

LAUNDRY

Clothes Dryer - Gas (electric usage only) .	5
Iron.	12
Washer - Automatic.	9

COOKING AND REFRIGERATION

Fry Pan	16
Oven, Microwave	20
Blender	1
Coffee Maker ("New" Drip Type - 2 pots per day).	30
Dishwasher.	30
Toaster	3
Crockery Cooker	12
Refrigerator-Freezer (Partial Frostfree, 14 cubic feet).	123
Freezer (Chest Type) 15 cubic feet.	100

HOME ENTERTAINMENT

Radio	7
Stereo.	9
Television, B/W Tube Type 160 watt.	29
Television, Color, Solid State.	37

MISCELLANEOUS

Three Clocks.	3
Vacuum Cleaner.	4
Humidifier (360 hours/month).	36
Room Air Conditioner (EER 6, 180 hours/ month).	207
Lights - 6 room living room	60

MONTHLY TOTAL	753

Monthly bill under current 1978 MPC rate structure - $20.15
Monthly bill under Proposed LRIC-Based rate structure - $27.82

Table 16, Continued

HEAVY USER

LAUNDRY	
Clothes Dryer - Electric	83
Iron	12
Washer - Automatic	9
Water Heater Quick Recovery	500
COOKING AND REFRIGERATION	
Fry Pan	16
Oven, Microwave	20
Range, with oven (self-cleaning)	129
Blender	1
Coffee Maker ("New" Drip Type - 2 pots per day)	30
Dishwasher	30
Toaster	3
Refrigerator-Freezer (Side-by-side, Frostfree, 19 cubic feet)	180
Freezer, Chest Type (15 cubic feet)	100
HOME ENTERTAINMENT	
Three radios	21
Stereo	9
Television, Black and White, Solid State, 55-watt	10
Television, Color, Tube Type, 300-Watt	55
Television, Color, Solid State 200-Watt	37
MISCELLANEOUS	
Five Clocks	5
Vacuum Cleaner	4
Garage Door Opener	15
Air Conditoner, Central (30,000 BTU 2½ tons, EER 6, 180 hours/month)	771
Furnace Fan (360 hrs/month)	216
Humidifier (360 hours)	43
8-room living area	80
MONTHLY TOTAL	2379

Monthly bill under current 1978 MPC rate structure - $50.72
Monthly bill under proposed LRIC-based rate structure - $94.29

marginal cost pricing that maximizes economic efficiency. Also, it would provide time to evaluate the results of peak-load pricing experiments and research conducted by utilities and public service commissions in other states.

In addition to introducing various benefits to the general public, implementing the proposed LRIC-based rate structure might also benefit Montana Power Company directly by easing financing difficulties. This may occur indirectly through the elasticity effect of price increases on collected revenue. More specifically, a price elasticity of demand for electricity between 0 and -1 implies that a price increase will generate more extra revenue for the utility than is lost to decreased consumption. Therefore, total revenue would still increase as a result of the price increase. This implies that not only will less power plants be needed as a result of raising the tail-block price to LRIC, but also that not as much outside revenue would be needed to finance that reduced system expansion relative to a declining block, average (historical) cost-based rate structure. As a result, less rate increase hearings would be needed, public resentment would be calmed, due to fewer rate increases profit margins would return (since rates were not longer entirely based on lower historical costs), and new investors would be attracted.

In conclusion, however, there are specific limitations of LRIC pricing that affect the results of this study as well as the possible adoption of this form of pricing. The theory of LRIC pricing involves pricing all kwhs consumed at the LRIC price. However, because a revenue constraint (requirement) is set through regulation, this degree of LRIC pricing would lead to excess (deficient) revenue in times of increasing (decreasing) costs.[20] Therefore, under our present situation of increasing costs of generation, it is necessary to price some of the non tail-block units (kwhs) at a price lower than LRIC. (Pricing the total estimated test year residential consumption of 1,298,580 Mwh at the proposed LRIC tail-block rate of $0.04088/kwh would result in a revenue amount of $53,085,950; $6,969,030 above the allowed limit.) This artificial pricing of interior block units then results in a "second best" situation (not quite the optimal with respect to economic efficiency). Even if all kwhs were priced at LRIC, the overall effect would still be "second best", since much of the American economy is not considered perfectly competitive and does not equate price to long-run marginal cost. Therefore, even though any deviation from LRIC pricing in interior block rates would result in a misallocation of resources, a stimulation of demand (through

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[20] The revenue constraint is based on recouping investment or historical costs which are lower than incremental costs under an increasing costs condition. Therefore, pricing all kwhs consumed at the higher LRIC-based rates would lead to collected revenue in excess of the historically-based constraint.

artificially low prices) and something less than a Pareto optimum, the proposed LRIC-based rates may or may not represent an improvement in social welfare relative to the current "second best," non LRIC-based decreasing block rate structure (see Morton, 1976, pp. 28-30).

The second major shortcoming of LRIC pricing involves the possibility of the "volatile revenue" problem discussed in Chapter 3. Montana Power Company representatives indicate that in near-future years a greater proportion of increased annual residential kwh consumption will result from increased kwh usage exceeding 310/kwh/month/residential customer, i.e., the proposed LRIC-based tail block (from a conversation with Bill Sherwood, General Office, Butte, Montana, August 8, 1977). Therefore, the results of the sensitivity analysis performed in Chapter 3 and given in Table 7 are more relevant than those in Table 8. Table 7 indicates that the greater potential percentage deviation in collected revenue would occur under the proposed LRIC-based rates relative to the MPC proposed 1978 rates. Whether or not this potential deviation is considered significant would depend on a ruling by the Montana Public Service Commission. Bill Opitz of the Montana Public Service Commission indicated (in a telephone conversation, August 4, 1977) that present policy does not require finding similar potential deviations from allowed revenue for proposed rate structures. Therefore, assuming that the percentage deviations in Table 7 are considered significant, a "volatile revenue" problem may exist if the LRIC-based rates are instituted. This potential problem would adversely affect Montana Power Company only when kwh consumption was reduced significantly (through the effect of the higher, LRIC-based tail-block price) so that excess unsold power was available to the system and a revenue deficiency would result. However, in a situation as this Montana Power Company could back-up some or all of its hydro generation supply by storing water behind dams and using its thermal generation plants as the base-load plants to supply power to the Montana system. The hydro plants would then serve as peaking plants, and the thermal plants would still operate efficiently since they would be operating at capacity. The potential left-over hydro power could then be sold later as resale power to out-of-state utilities or Montana cooperative utilities or as MPC system power if demand increases. There are, however, certain constraints on this particular strategy. Only so much hydro capacity can be stored for any length of time. The size of the dams, whether the dam is located on a river or lake, flood control, and instream constraints that pertain to fish, wildlife, and recreation all become relevant considerations. Nevertheless, because of the large and increasing demand for electricity in Washington and Oregon (see Mullaney, 1978), the excess power problem may be considerably simplified since these states would probably buy much if not all of the excess power available from Montana Power Company. Another possible solution to the volatile revenue problem would involve the establishment of a form of escrow fund, whereby excess revenue generated in "fat" years (because of unanticipated kwh consumption) would be placed in a state-regulated account and distributed accordingly to the utility in "lean" years (because of a decrease in anticipated kwh consumption). This would stabilize the revenue throughout the period the rates were in effect. Currently, this practice is not being used in Montana even though it is not considered illegal (from a telephone conversation with Bill Opitz, Montana Public Service Commission, Helena, August 4, 1977).

APPENDICES

APPENDIX A

APPENDIX A

GLOSSARY OF RELEVANT ECONOMIC AND TECHNICAL TERMS

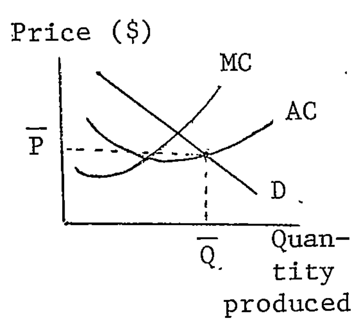
Allocation of Resources - an economist's description of how land, labor, and capital are distributed among various production activities.

Allowable Rate of Return - the proper or reasonable (as determined by the public service commission of the state of interest) rate of return permitted on the investment capital of the regulated company.

Average Cost (AC) - cost per unit of output (i.e., commodity produced).

$$AC = \frac{\text{total cost of production}}{\text{number of units produced}}$$

Average Cost Pricing - pricing output according to its average cost. This implies to produce until price equals average cost of production (i.e., $\overline{Q}$ units at $\overline{P}$ per unit where D represents the demand for the commodity or service at various price levels and MC and AC represent the marginal and average cost of production at various output levels).



Capitalization Ratio - a measure of what the capital structure of a company is (i.e., how the company is financed or what proportion of capital came from long term debt, equity or common stock issuance, and preferred stock).

Common Plant - that portion of the total electrical plant that is considered by the utility to be of common use to all phases of providing electrical power to the consumer (i.e., production, transmission, distribution).

Competition (Perfect) - an economic concept that describes a situation characterized by a large number of sellers and buyers and a non-differentiable product.

Correlation - a concept that refers to the degree of association between variables.

Demand - a schedule that indicates the quantities demanded of a commodity or service at various price levels for a given period of time.

Depreciation - a capital cost ammortization designed to reflect the general downward trend in the service values of the fixed assets.

Economics of Scale - this implies that a firm can reduce its long run average cost of production by increasing its plant size.

Elasticity - percentage response (increase or decrease) of quantity demanded of a commodity to a given change in price. A more elastic demand would exhibit a greater response to price changes.

Excess Capacity - the electrical generation facilities that are used at full output only at high demand (peak) times and lay dormant at other times.

Externalities - divergence between private costs (from the firm's viewpoint) and social costs (from society's viewpoint) or between private gains (from the consumer's viewpoint) and social gains.

Fixed Cost - a cost that doesn't vary with the production rate, e.g., rent on a building must be paid regardless of whether the firm produces if a contractual obligation exists.

Forecast - a prediction of future states usually preceded by certain assumptions and a sophisticated analysis of past and present data.

Fossile-Fuel, Steam-Electric Plant - an electricity generation facility that uses coal, oil, natural gas, or some combination of these to fuel the generation of steam used to drive electricity-producing turbines.

Fuel-Adjustment Clause - an agreement between a utility and its governing commission to allow fuel-cost increases to be passed directly to electricity consumers through rate increases.

Generation Cost - the total cost of electrical generation facilities or plant.

Heat Rate - a measure of the efficiency of generation of a generation plant. The higher the heat rate, the better.

Historical or Embedded Costs - the capital costs of existing plant facilities, discounted appropriately to correct for depreciation.

Incremental Cost (IC) - the increment in total cost that will result from producing the particular amount and type of the potential incremental product in addition to the existing other production.

In Real Terms - indicates that changes in prices or costs are in current (1976) or some base-year (e.g., 1970) dollars that have been corrected for inflation.

Kw - kilowatt - a unit of measure of the power of an electricity generating facility.

Kwh - kilowatt-hour - a unit of energy equal to that expended by one kw in one hour.

Lead Time - the time period between when construction of a plant first starts and when the plant goes on line.

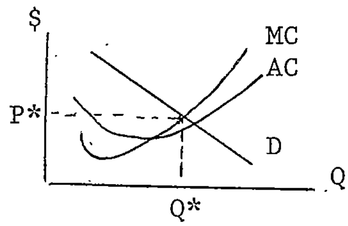
Load Curve (of a utility) - a graphical representation that indicates the past or predicted electricity demand in kwhs at various times of the day, month, or year.

Load Factor - a utility's average load (in kwh per period of time) expressed as a percentage of the peak load during that period (e.g., month).

Long Run (LR) - a period of time long enough for all factor inputs of production (e.g., labor, capital, etc.) of some commodity to be variable. This implies that the size of a plant can be enlarged or decreased in the long run.

Marginal Cost (MC) - the extra cost incurred (saved) by producing (not producing) one more unit of a commodity.

Marginal Cost Pricing - pricing output according to its marginal cost. This implies to produce until price (given by the demand curve



for a good or service) equals marginal cost of production (i.e., produce and offer for sale Q* units at a price of P*).

Megawatt (MW) - 1 Mw = 1000 Kw.

Mill - a unit of measure of cost. 10 mills equal 1 cent.

Nuclear Power Plant - an electricity generation facility that uses highly radioactive material (usually enriched uranium) in the fuel cycle.

Pareto Optimal Allocation - a situation whereby goods or resources are distributed to the members of society in such a way that any further redistribution would result in making at least one person worse off.

Peak-Use Period - a description of the time period when electricity customers use the most electrical energy (e.g., mid-morning, August in Florida, etc). A non-peak period might be the middle of the night when there is very little drain on the electrical network.

Rate Base - the total of invested capital on which the company is entitled a reasonable rate of compensation.

Rate Structure - a relationship that shows the various rates charged for a particular service as a function of consumption (e.g., kwh).

Regression - a statistical technique whereby the relationship between one independent variable and one control variable (i.e., linear regression) or between one independent variable and several control variables (i.e., multiple regression) is examined using empirical data.

Regulatory Lag - the length of time between the request for a rate increase to a regulatory commission (and by a utility) and the granting (or denial) of that increase.

Reproduction Costs - the current costs to reproduce the existing plant facilities.

Short Run (SR) - a period of time so short that some factors of production cannot be varied (e.g., the size of an electrical generation facility cannot be substantially increased in a period of a few months).

Social Welfare - the well-being of the society of interest.

Stack-Gas Scrubbers - pollution control equipment that is normally used in coal-fired generation facilities to control the amount of fly-ash and/or other pollutants released into the atmosphere from smoke stacks.

Stock Equity - the shares of common stock outstanding.

Supply - a schedule that indicates the quantities supplied of a commodity or service at various price levels for a given period of time.

Time Series - a compilation of data which involves observations of variables taken at various points in time (e.g., monthly, quarterly, yearly). It can exhibit trends, cycles, and seasonal and random variation. Analysis of time-series data usually concerns predicting or forecasting future values of the variables in question on the basis of historic data or experience.

Variable Cost - a cost that is dependent on the level of output (e.g., labor costs are usually variable costs).

APPENDIX B

APPENDIX B

DATA

1. Source: Annual Report of the Montana Power Company to the Federal Power Commission - Year Ended December 31, 1976; Form 1

(a) p. 431 Assume 1977 has the same hydro generation as 1976, namely, 3,741,731 Mwh.
p. 432 Don Gregg of the Montana Power Company (MPC) Planning Department in Butte said it would be reasonable to assume the 1977 Net Generation of the Bird and Corette plants would be approximately the same as that in 1976 (i.e., line 12), namely 662 Mwh and 1,029,266 Mwh respectively.
p. 432a Don Gregg, MPC Planning Department, said that a more realistic load factor to use for the estimated 1977 operation of Colstrip 1 and 2 would be 0.75. This applied to the Total Installed Capacity figure (i.e., line 5) of 358,371 kw resulted in an estimated 1977 generation of 2,354,497 Mwh. Therefore, total estimated 1977 thermal generation would be 3,384,425 Mwh.

(b) pp. 422-423 Don Gregg, MPC Planning Department, identified each portion of the purchased power for 1976. Total hydro purchased power amounted to 525,502 Mwh at a weighted cost of $0.0032/kwh. Total thermal and nuclear purchased power amounted to 831,548 Mwh at a weighted cost of $0.00440/kwh. Gregg said it would be reasonable to assume the same Mwh totals for 1977, although some slight reduction in the total figure may result because of increased output of Colstrip 2 in 1977. The cost levels were inflated at a 6.5% rate (see Oregon Department of Energy, 1976, pp. 15-16) to obtain respective estimated 1977 cost levels of $0.00340/kwh and $0.00470/kwh.

(c) p. 424 1976 Interchange Power resulted in delivery of 86,658 Mwh to other utilities and public authorities at a charge of $67,626. This implies a cost to MPC of $0.00078/kwh. Don Gregg, MPC Planning Department, said to assume 1977 involved the same number of Mwh. The cost was inflated at a rate of 6.5 percent again to obtain an estimated 1977 cost level of $0.00083/kwh. Gregg also said it is "nearly impossible to identify which portions of the total figure of 86,658 Mwh are from hydro generation and which are from thermal or nuclear." Therefore, it was assumed the total figure involved entirely hydro-generated Mwhs.

(d) pp. 412A-413A Don Gregg, MPC Planning Department, identified the Sales for Resale as either from hydro or thermal sources. Total 1976 sales for resale from hydro sources amounted to 97,832 Mwh for a credit of $0.001/kwh. Total 1976 sales for resale from thermal sources were 1,997,247 Mwh for a credit of $0.00740. Gregg said to adjust the thermal sales for resale by the increased output to Colstrip 1 and 2 anticipated in 1977 (i.e., 172,437 Mwh at a 0.75 load factor) to get a 1977 estimate for sales for resale from thermal sources of 2,169,684 Mwh. The 1977 estimate for sales for resale from hydro sources was assumed to be the same as the 1976 figure. The 1976 credit levels were inflated at a 6.5 percent rate to obtain 1977 credits of $0.00107/kwh and $0.00788/kwh for hydro and thermal respectively.

(e) p. 425E Don Gregg, MPC Planning Department, said that the 1976 figure for Wheeled Power taken from MPC customers (i.e., 866,784 Mwh) was essentially all from hydro sources. The credit for that power was $0. Gregg said to assume the 1977 figures were the same.

(f) p. 431 Bill Sherwood of the MPC General Office in Butte said to assume a 10 percent loss figure for 1977. (The 1976 figure was 8.17 percent of total available power for sale and resale.) The total estimated 1977 available power for sale and resale is 7,529,764 Mwh (i.e., from Table 2, $H+H_p+T_p+T+H_I+H_W$ assuming "Other" generation equals zero). Therefore, total estimated 1977 losses due to transmission and distribution through the MPC system are 752,976 Mwh where:

net hydro power losses = 331,387 Mwh at a weighted generation cost of $0.00271/kwh.
i.e. losses = $(10\%)(H+H_p+H_I+H_W)$

$$\text{cost} = \frac{(H+H_I+H_W)(P_H)+(H_p)(P_{HP})}{H+H_p+H_I+H_W}$$

using values in Table 2.

Net thermal power losses = 421,589 Mwh at a weighted generation cost of $0.00842/kwh. (The calculation procedure is similar to that above.)

The estimated incremental thermal losses equal 275,940 Mwh, i.e., (10%)(P_I), at a cost of $0.02016/kwh where P_I is given in Table 2.

2. (a) Source: Letter and enclosures from D.T. Berube, Assistant Chief Engineer, Montana Power Company (MPC), to Gay Lamb, The Mitre Corporation, June 29, 1976.

The following figures relate to Colstrip Units 3 and 4:

Capacity = 1400 Mw
Output = 9,198,000 Mwh at a Load Factor of 0.75. MPC only has rights to 30 percent of this figure, or 2,759,400 Mwh.

(b) Source: <u>Future Energy Options for Oregon, Appendix IV, Future Electricity Prices in Oregon: A Preliminary Analysis</u> by the Oregon Department of Energy.

The following are estimates relating to Colstrip 3 and 4 for the anticipated first year of operation of both plants (i.e., 1981):

Operation and maintenance expense = $0.00462/kwh.
i.e., p. 52 figure inflated at 6.5 percent per year for 1976 and 1977.

Fuel expense = $0.00489/kwh.
i.e., p. 47 figure inflated at 6.5 percent per year for 1976 and 1977.

Total plant capital cost* = $878,116,990
i.e., p. 32 figure inflated at 6.5 percent per year for 1976 and 1977 where $537/kw for Colstrip 3 and $569/kw for Colstrip 4 were used.

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*This is also considered the net incremental plant for rate base determination.

Depreciation expense = \$23,732,867.
i.e., assuming straight-line depreciation and a 37 year useful life of plant.

Rate of return = 8.45 percent.
i.e., from Appendix B, p. 104, 3b.

Annual return on capital expense = \$0.00807/kwh

i.e., $\frac{(0.0845)(\$878,116,990)}{9.198 \times 10^9 \text{ kwh}}$

Depreciation expense = \$0.00258/kwh

i.e., $\frac{\$23,732,867}{9.198 \times 10^9 \text{ kwh}}$

Estimated cost of incremental generation = \$0.02016/kwh
i.e., 0.00462 + 0.00489 + 0.00807 + 0.00258

3. Source: The MPC-Electric Utility Allocated Cost of Service Study for the Test Year Ending 12-31-77 - Proposed Rates and OC-DR RB Run Date: 11/12/76, by EBASCO Services, Inc.

(a) Expenses allocated to the residential class (estimated 1977 dollars):

Operation and maintenance

Production expenses are already in the calculations for cost of generation

Transmission and subtransmission = \$1,330,946	i.e., from Operation and Maintenance Expenses, Account #16.
Distribution Demand = 1,719,786	
Distribution Customer = 3,153,548	
Sales Accounts = 808,636	
Customer Accounts = 2,152,044	

Depreciation

Production expenses are already in the calculations for cost of generation

Transmission and Subtransmission = \$745,760	i.e., from Depreciation Expenses, Account #17.
Distribution Demand = 767,213	
Distribution Customer = 763,464	
Customer Accounts = 76,593	
Sales Accounts = 17,070	

Property, Payroll, and Other Taxes

Total of Production*, Transmission and Subtransmission, Distribution Demand, Sales = $3,520,395 Distribution Customer, Customer Accounts = 1,034,995	i.e., from Accounts #18, #19, #20.

Federal Income Tax

Total (no breakdown was given) = $3,395,744	i.e., from Account #37

Investment Tax Credit

Total production, transmission, etc. = -$1,332,887 Distribution Customer, etc. = -$288,508 (See note * on page 5)	i.e., from Account #24

Investment Tax Credit Amortization (Net)

Total production, etc. = $1,116,412 Distribution Customer, etc. = $241,653 (See note * on page 5)	i.e., from Account #23.

Provision for Deferred Tax Amortization

Production = -$260,231 (See note * on page 5)	i.e., from Account #25.

Provision for Deferred Tax Liberalized Depreciation

Total Production, etc. = $1,813,538 Distribution Customer, etc. = 315,223 (See note * on page 5)	i.e., from Account #26.

*No data was given on production breakdown. Therefore, one cannot "justifiably" allocate the total to different forms of generation, and so the total is distributed over the residential class kwh consumption (rather than portions to each form of production).

Total estimated 1977 expenses allocated to the residential class = $13,642,382
i.e., sum of the relevant entries above (excludes Distribution Customer and Customer Accounts)

Total estimated 1977 residential class customer charges from expenses = $7,449,012
i.e., sum of the above entries listed for Distribution Customer and Customer Accounts.

Estimated number of 1977 MPC customers = 214,295
Estimated number of 1977 residential customers = 177,012
Estimated 1977 residential kwh consumption = 1,298,580 Mwh
i.e., from Allocation Factor Schedule.
i.e., Production Power Supply Figure minus 10 percent for transmission and distribution losses.

Therefore:
Estimated residential transmission, distribution, and general expenses = $0.01050/kw
Estimated residential customer charges due to expenses = $42.08/customer/year
Estimated 1977 average residential use = 611 kwh/month/customer

(b) Rate base allocated to the residential class (estimated 1977 dollars)

<u>Net Plant in Service</u>

Production plant is already included in cost of generation.
Transmission and Subtransmission Plant = $15,137,985
Distribution Demand = $33,949,285
Distribution Customer = $29,739,164
Customer Accounts = $2,999,873
Sales Accounts = $652,030
i.e., from Account #31

Note: Net Plant in Service includes general, common and intangible plant, plant adjustments, construction work in progress, an AFUDC (i.e., allowance for funds used during construction) adjustment, and a plant acquisition adjustment. Also, a figure for depreciation reserve is subtracted from the corresponding account listed.

Materials and Supplies

Production, etc. = $1,315,833 i.e., from
Distribution Customer, etc. = $660,003 Account #07
(See note * on page 5)

Working Capital

Production, etc. = $1,137,829 i.e., from
Distribution Customer, etc. = $1,059,415 Account #08
(See note * on page 5)

Total Estimated 1977 rate base = $88,228,962
(excluding production plant and customer charges)

Total Estimated 1977 customer charge rate base = $34,458,455

Desired rate of return (ROR) from the residential class = 8.45 percent

Estimated revenue constraint for the residential class for the test year = $46,116,920
i.e., from Account #33.

Therefore:
Estimated 1977 return on investment (ROI) per kwh of residential consumption in the test year (excluding customer charge rate base and production plant) = $0.00574/kwh.
i.e., (8.45%)($88,228,962) ÷ 1,298,580,000 kwh.

Estimated 1977 ROI in the customer charge rate base per test year residential customer = $16.45/residential customer

(c) Existing Hydro Generation

Production plant original cost in test year = $89,856,375
(including depreciation reserve)
i.e., 29 percent of Total Production Net Plant in Service Account #31 figure (OC RB). Bill Opitz, Montana Public Service Commission, said it would be reasonable to partition the total figure according to the percentage given on pages 401-402 of the FPC Form 1 (source 1 in this Appendix) (i.e., 29 percent).

Less depreciation reserve = -26,016,954

i.e., 62 percent of Total Depreciation Reserve, Account #06. Production percentage determined according to that given in FPC Form 1, page 408 for Steam Production, Hydro as a fraction of Total Production Accumulated Depreciation.

Net hydro production plant rate base for test year = $63,839,421

Estimated depreciation expense for test year = $1,149,110
i.e., assume same 1.8 percent figure as that for 1976 using the $859,783 depreciation expense for hydro (p. 429 in FPC Form 1) compared to 1/1/76 Hydro OC Plant figure minus accumulated depreciation for 1975 (pages 401, 408 in 1975 FPC Form 1), $46,521,944. Therefore, 1.8 percent of Net Hydro Production Plant Rate Base of $63,839,421

Estimated operation and maintenance expenses for test year (including fuel) = $3,117,872
i.e., First, adjust for the increase in operation and maintenance expenses (as a result of the increase in Colstrip 1 and 2 output) at the same 4.26 mills/kwh (page 432a FPC Form 1 assuming Load Factor = 0.75. Adding this figure to Total Power Production Expenses-Steam and Hydraulic Power (ignore "Other") and comparing Hydro operation and maintenance expenses to this total gives approximately 24 percent (pages 417-18 FPC Form 1). Assume this same proportion of Test Year Operation and Maintenance Account #16, Total Production.

(d) <u>Existing Thermal Generation</u>

Production plant original cost in test year = $219,993,180 (including depreciation reserve)
i.e., (see 3c) 71 percent of Total Production Net Plant in Service figure, Account #31.

Less depreciation reserve = -$15,945,875
i.e., see 3c.

Net thermal production plant rate base for test year = $204,047,305

Estimated depreciation expense for test year = 4,470,827 i.e., Total Production Depreciation Expense figure (Account #17) minus Hydro Depreciation Expense figure in 3c. (Ignore "Other Generation)

Estimated Operation and Maintenance (O & M) expenses for test year = $9,873,262 (including fuel)
i.e., Total Production O & M Expense figure, Account #16 minus Hydro O & M figure in 3c (Ignore "Other" generation)

Estimated 1977 output = 3,384,425 Mwh
i.e., see 1a.

ROI = (8.45%)($204,047,305) = $17,241,997
i.e., see 3b, d.

Estimated 1977 cost of existing thermal generation = $0.00933/kwh of generation

4. Source: 1976 Montana Power Company (MPC) Billing Accumulation Statements

(a) Estimted revenue from the MPC proposed residential rate schedule:

kwh range	# of bills[1]	# of kwh[1]
0-20	213,078	337,529*
		37,824,720[L]
		38,162,249 @ $0/kwh = $0
21-100	130,102	5,743,063*
		140,890,720[L]
		146,633,783 @ $0.0716/kwh=$10,498,978
101-200	197,797	10,203,272*
		156,333,700[L]
		166,536,972 @ $0.0502/kwh=$8,360,156

[1]Sum of residential electric, rural-other, and rural village 1976 monthly bills for maximum usage in the indicated interval.
*Corresponding to kwhs exactly in that range.
[L]From larger customer consumption.

201-above	1,563,337 (i.e., 74% of total)	805,684,400* @ \$0.0250/kwh = (i.e., 70% of total)	\$20,142,110
Total	2,104,314	1,157,017,340	

Customer Charge = \$4,755,750
i.e., (2,104,314)(2.26)

Total Revenue = \$43,756,994

(b) Estimated revenue from the proposed LRIC-based residential rate schedule:

kwh range	# of bills[1]	# of kwhs[1]
0-298	747,689	90,341,039*
		404,274,250[L]
		494,588,289 @ \$0.0204/kwh = \$10,089,600
299-611	679,768	103,949,410*
		211,179,380[L]
		315,128,790 @ \$0.02653/kwh = \$8,360,367
612-above (i.e., 32% of total)	676,857	347,300,261* @ \$0.04088/kwh = (i.e., 30% of total) \$14,197,634
Total	2,104,314	1,157,017,340

Customer Charge = \$10,269,052
i.e., (2,104,314)(4.88)

Total Revenue = \$42,916,653

(c) Adjusting the proposed LRIC-based residential rate schedule so that the revenue constraint and requirement is attained and a majority of customers face an LRIC marginal price:

kwh range	# of bills[1]	# of kwhs[1]
0-298	747,689	494,588,289 @ \$0.0204/kwh = \$10,089,600

299-430	298,893	24,632,420*
	1,046,582	138,562,890L

Total = 163,195,310 @ \$0.02653/kwh = \$4,329,570

491-above	1,057,732	499,233,700* @ \$0.04088/kwh =	
	(50.3% of total)	(43% of total)	\$20,408,670
Total	2,104,314	1,157,017,340	

Customer charge = \$8,929,154 = \$4.24/customer

i.e., $\frac{8929154}{2104314}$

Total Revenue = \$43,756,994

However, the LRIC-based rate schedule is adjusted further so as to: (1) face more than 50.3 percent of the total number of residential customers with an LRIC marginal price, and (2) result in a "politically" acceptable customer charge as that proposed under the MPC proposed rate schedule (i.e., \$4,755,750 or \$2.26 per customer). The revised LRIC-based rate schedule involves an interior-block price based on the weighted cost of existing hydro- and thermal-generated electricity. The calculations and corresponding rate schedule are as follows:

$$\text{Weighted cost of} = \frac{P_1(H+H_p+H_I+L_H) + P_2(T+T_p+L_T)}{H+H_p+H_I+H_W+L_H+T+T_p+L_T}$$

$$= \frac{0.02040(2,462,157) + 0.02653(3,794,384)}{6,256,541}$$

$$= \$0.02412/\text{kwh}$$

where p_1 and p_2 are the first and second interior block prices from the proposed LRIC rate schedule, and the other symbols represent entries from Table 2 in the main body of this paper.

kwh range	# of bills[1]	# of kwhs[1]
0-310	776,079	98,985,051*
		411,752,850L

Total = 510,737,900 @ \$0.02412/kwh = \$12,318,998

311-above	1,328,235 (i.e., 63% of total)	654,279,400* @ \$0.04088/kwh = (i.e., 57% of total)	\$26,746,941

Customer Charge = \$4,691,055 = \$2,23/customer

Total Revenue = \$43,756,994

Revised LRIC-based residential rate schedule: Customer charge \$2.23/meter/month

Monthly kwh Consumption	Energy Charge (per kwh)
0-310	\$0.02412
311-above	\$0.04088

The previous rate schedule was converted from a 3-block structure to a 2-block structure with a higher first-block price to emphasize economic efficiency under the given revenue and customer charge constraints, as well as an equity consideration. As a result, low users will not face a marginal price as low as the previous artificially-low first-block price, yet still benefit from lower consumption levels through the lower interior block price (relative to the LRIC tail-block price).

5. Source: Montana Power Company, Budget Department chart entitled "System Comparison, 1963-1976".

(a) Using data on annual residential Mwh consumption for the years 1967-1976 inclusive, a simple linear regression was performed to determine a trend line relationship between annual residential Mwh consumption (C) and year (Y). The results are:

$\hat{C}$ intercept = 654,940.9

Slope = 52,925.6

Correlation Coefficient = 0.99

$\hat{C}$ (y=1977) = 1,237,122 Mwh
S=3.03

Var = 9.17

Equation of the regression line: $\hat{C} = 654{,}940.9 + 52{,}925.6\ Y$

(b) Next, the deviations (D) from the trend line values were found:

Y	D		$\hat{C}$	$D/\hat{C}$
1 (or 1967)	9,224.5			
2	4,144.9			
3	6,980.3			
4	-16,322.2	= N	866,643	-0.019
5	- 6,707.8			
6	12,354.6			
7	- 8,718.0			
8	-34,752.5			
9	12,670.9	= P	1,131,271	0.011
10 (or 1976)	21,125.3			

Also, in the above table the second highest negative deviation (N) and the second highest positive deviation (P) are identified, and the corresponding values for $\hat{C}$ and $D/\hat{C}$ are given.

On the basis of data from the last 10 years one can (roughly) say that with 90 percent confidence the 1977 value for residential kwh consumption will be within $D_p/\hat{C}_p$ x 100 percent of the trend line 1977 value ($\hat{C}$), where the $D/\hat{C}$ figure corresponds to p. A "high" 1977 estimate for C can then be found. Through a similar process a "low" 1977 estimate for C can also be determined. The calculation is as follows:

$$\text{"High" } 1977\ \hat{C} = \hat{C}(y{=}1977)(1 + D_p/\hat{C}_p \times 100\%)$$
$$= (1{,}237{,}122)(1 + 1.1\%)$$
$$= 1{,}250{,}731 \text{ Mwh}$$
$$\text{"Low" } 1977\ \hat{C} = \hat{C}(y{=}1977)(1 + D_N/\hat{C}_N \times 100\%)$$
$$= (1{,}237{,}122)(1 - 1.9\%)$$
$$= 1{,}213{,}617 \text{ Mwh}$$

However, to be consistent with the other calculations made in this study, the EBASCO cost of Service Study 1977 test year estimate for residential consumption ($\overline{C}$) was used instead of $\hat{C}$ (Y=1977). The new "high" and "low" estimates for 1977 residential consumption are found through a similar procedure:

$$\text{"High" } 1977\ \overline{C} = \overline{C}\ (1+1.1\%)$$
$$= 1{,}298{,}580\ (1+1.1\%)$$
$$= 1{,}312{,}864 \text{ Mwh}$$
$$\text{"Low" } 1977\ \overline{C} = \overline{C}\ (1-1.9\%)$$
$$= 1{,}273{,}907 \text{ Mwh}$$

(c) The estimated extra kwh consumption (due to underestimation) is then 14,284 Mwh, while the estimated deficient kwh consumption (due to overestimation) is then 24,673 Mwh.

Assuming these kwy differences involve only tail-block kwh consumption (or conservation), the percentage change in collected revenue under the various rate schedules is:

	Under Proposed LRIC-Based Rates	Under MPC Proposed Rates
If actual consumption climbed to the "high" estimate	$\frac{(14{,}284{,}000)(0.04088)}{43{,}756{,}994} = 1.3\%$	$\frac{(14{,}284{,}000)(0.0250)}{43{,}756{,}994} = 0.8\%$
If actual consumption climbed to the "low" estimate	$\frac{-(24{,}673{,}000)(0.04088)}{43{,}756{,}994} = -2.3\%$	$\frac{-(24{,}673{,}000)(0.0250)}{43{,}756{,}994} = -1.4\%$

Assuming that all extra kwh (or deficient kwhs) above (or below) the estimated test year residential consumption are consumed (or conserved) in the first non-zero priced block, the percentage change in revenue under both rate schedules is:

	Under Proposed LRIC-Based Rates	Under MPC Proposed Rates
If actual consumption climbed to the "high" estimate	$\frac{(14{,}284{,}000)(0.02412)}{43{,}756{,}994} = 0.8\%$	$\frac{(14{,}284{,}000)(0.0716)}{43{,}756{,}994} = 2.3\%$
If actual consumption climbed to the "low" estimate	$\frac{-(24{,}673{,}000)(0.02412)}{43{,}756{,}994} = -1.4\%$	$\frac{-(24{,}673{,}000)(0.0716)}{43{,}756{,}994} = -4.0\%$

6. Source: Telephone conversation with Don Gregg, Montana Power Company, Planning Department, Butte, August 2, 1977.

Mr. Gregg said that no Montana Power Company estimate for year 2000 residential kwh consumption had been made. However, he suggested that to find a "shot in the dark" estimate, assume a 5 1/2 percent growth rate for the next ten years, due to the "natural gas scare" and the entry into the home market by the "war baby" segment of the population. Thereafter, he suggested a 4.8 percent growth rate as a result of the increased use of solar heat in residential structures. Applying these load growth rates to the 1976 residential kwy consumption of 1,205,322 Mwh (page 414 FPC Form 1) results in a year 2000 estimate of residential kwy consumption of 3,969,040 Mwh.

7. An electricity bill under the current 1978 MPC residential rate structure can be represented by

$$1.69 + 80(0.0538) + 100(0.0376) + (x - 200)(0.0188)$$

where x is the monthly kwh consumption level ($x \geq 200$). Similarly, a bill under the proposed LRIC-based rates can be represented by

$$2.23 + x(0.02412)$$

when x is less than 310 kwh and by

$$2.23 + 310(0.02412) + (x - 310)(0.04088)$$

when x is greater than or equal to 310 kwh. By equating the algebraic phrases corresponding to the two relevant rate structures, the monthly kwh consumption level that results in equal bills can be found.

i.e., let x = a number less than 310

$$1.69+80(0.0538)+100(0.0376)+(x-200)(0.0188)=2.23+x(0.02412)$$
$$5.994 + 0.0188x = 2.23 + 0.02412x$$
$$3.764 = 0.00532x$$
$$707.52 = x$$

This is an invalid solution since it contradicts how x was defined. Therefore, the bills aren't equal at a consumption level less than 310 kwh per month. Let x = a number greater than or equal to 310.

$$1.69 + 80(0.0538) + 100(0.0376) + (x - 200)(0.0188) = 2.23 + 310(0.02412) + (x - 310)(0.04088)$$
$$5.994 + 0.0188x = -2.9656 + 0.04088x$$
$$8.9596 = 0.02208x$$
$$405.77898 = x$$

Therefore, at a monthly consumption level of 405.77898 kwh bills under the two rate structures will be the same, namely $13.6226.

APPENDIX C

APPENDIX C

CONVERSION FACTORS

1. 8760 hrs/yr.

2. 10 mills/cent or 1000 mills/dollar

3. Determining annual net generation (ANG):

$$\text{ANG} = (\text{Plant capacity in KW}) \times (\text{Load Factor}) \times \frac{8760 \text{ hrs}}{1 \text{ yr}}$$

4. Determining mills/kwh cost:

$$\frac{\text{mills}}{\text{kwh}} = \frac{\text{Total Cost (\$)}}{\text{ANG}} \times \frac{1000 \text{ mills}}{1\$}$$

5. Determining $/kw cost:

$$\frac{\$}{\text{kw}} = \frac{\text{Total Cost (\$)}}{\text{Plant Capacity (in kw)}}$$

6. Converting $/kw to $/kwh:

$$\frac{\$}{\text{kwh}} = \frac{\$}{\text{kw}} \times \frac{1 \text{ yr}}{8760 \text{ hrs}} \times \frac{1}{\text{Load Factor}}$$

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