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
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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.

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Date September 14, 1978

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by

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

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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	Percent Ownership Public	Percent Ownership 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

[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,

[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 projected costs of system increments in capacity rather than of imbedded costs (Guth, 1974, pp. 8-9).

Furthermore, economic efficiency will result only when pricing occurs at social marginal costs. This implies that those who use a little less electricity save the equivalent of social 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

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[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

[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 relevant 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

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[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