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COMMENTS ON EBASCO SERVICE'S APPROACH TO PEAK-LOAD PRICING

Prepared by
Walter A. Morton

Prepared for
ELECTRIC UTILITY RATE DESIGN STUDY:
A nationwide effort by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners

November 28, 1977

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NOTE TO READERS

This material was prepared by Dr. Walter A. Morton. It contains information that will be considered by the Project Committee along with other reports, data, and information prepared by several other consultants, the various task forces, and other participants in the rate design study. This document is not a report of the Project Committee. Its publication is for the general information of the industry. The Project Committee will report its findings to the National Association of Regulatory Utility Commissioners in a comprehensive report that will be published in 1977.

Dr. Morton's material contains the findings and reflects the views of the consultant. The distribution of the document by the rate design study does not imply an endorsement by the Project Committee or the organizations, utilities, or commissions participating in the rate design study.

Dr. Morton was retained to comment upon portions of the research reported by Ebasco Services Inc., specifically The Development of Various Pricing Approaches: Topic 1.3 (March 1, 1977), Costing for Peak-Load Pricing: Topic 4 (May 4, 1977), Costing for Peak-Load Pricing: Topic 4--Results for Virginia Electric and Power Company (June 6, 1977), and Ratemaking: Topic 5 and Illustrative Rates for Five Utilities (June 6, 1977). Topics 1, 4, and 5 were also examined by National Economic Research Associates, Inc., and by the respective task forces. Their work is reported in separate documents.

Topic 1 is described in the Plan of Study as:

> Topic 1 The Analysis of Various Pricing Approaches
>
> The first topic (1.1) would be a "state-of-the-art" review as to the purpose of rates and possible uses of price as policy instruments, particularly with respect to various aspects of peak-load pricing. The development of the roles of fully allocated historic cost pricing and long-run incremental cost pricing would be examined and the rationales supporting them appraised.
>
> The starting point would be the premise that rates must be just and reasonable and that they must effect an overall balance between the interest of the owners of the enterprise--the stockholders--and the ratepayers. Thus, absent some fairly radical

statutory development, there must be an overall revenue constraint in ratemaking.

Second, there is the general precept that rates must not be unduly preferential or unduly discriminatory. This introduces a principle of equity. The general constraint here is that differentials between classes of service and rates within classes must be based on some notion of cost of service. Whether this is the more traditional, fully allocated historic cost of service or "fully allocated" marginal cost of service is a matter to be considered later. Third, there is the historic concept of continuity in ratemaking under which customers are said to have a right to be protected against unnecessarily abrupt changes in the structure of rates. The justification for this assertion arises from the capital-intensive nature of electric utilization, where customers have to make substantial investments which are theoretically based, in part at least,on their price expectations. To this might be added an extension of the concept of equity; somehow it does not seem to some "fair" to disturb unduly customers' expectations.

Finally, simplicity and clarity are considered to be an essential of proper ratemaking, not only from the standpoint of the customers' ability to understand rates, but also from the standpoint of rate administration by the commission and the companies.

Often these various precepts are in conflict with each other and the regulator must choose which precept he considers the most binding. Here there is little statutory guidance, but rather the regulator's judgment is brought into play.

Into this set of somewhat conflicting signals has been injected the economic role of price, more particularly in the last five years. A version of marginal cost, based on long-run incremental cost (LRIC), has been introduced into various rate proceedings in guiding certain of the utility companies as to the directions in which rates should move. Moreover, even before this, utility companies were moving in the direction of peak responsibility pricing, with demand charge ratchets, off-peak rates, summer-winter differentials, etc.

Most recently, capital shortages, increasing costs of fuel and equipment, and declining load factors have led to more frequent and more insistent asking of the question as to whether pricing as generally practiced has contributed to an uneconomic growth of the peak, and whether basic changes in the price structure might help to curb this tendency.

A reasoned debate is taking place in academic and trade journals as to the purposes and effects of rates based on these different principles. An overview of the theoretical basis of the different positions, and a comparison of the ratemaking philosophies would be a useful first step to clarifying the problem.

The second topic (1.2) would be to review the theoretical and/or applied work done in the United States, France, England, Germany, Sweden and other countries in connection with peak-load pricing. This review would then examine experience with peak-load pricing where it has been applied. Particular emphasis would be directed toward an examination of these tariffs in terms of the peak-limiting and capital-saving results and their possible applicability to conditions in the United States.

In addition, some United States utilities have introduced interruptible rates, summer-winter differentials and/or ratcheted demand metering. The basis for these and their effectiveness will be examined and their relationship to traditional ratemaking and peak-load pricing will be reviewed.

Assuming that these two investigations show a promising basis for pursuing time-related rates further, the third topic (1.3) would be to develop a methodological framework to be employed in developing time-related rates in the United States electric industry. This would be in the form of a preliminary working paper, with the emphasis not on "should" this course be followed, but rather "how" to proceed.

Without prejudging the contents of this paper, the sequence of the likely, necessary steps is outlined here, since it is important to the understanding of what follows. The first step would require a determination of the periods to be used in a peak-load pricing rate schedule and, therefore, for which costs are to be determined. Typically, this would involve several seasons during the year and several times of day. Only if the rate schedules are reasonably simple can they be effective. Step 2 would involve the determination of appropriate running costs (fuel and other variable costs) for each of the pricing periods selected in Step 1. Step 3 would involve the determination of the various categories of appropriate capacity costs (generation, transmission and distribution). In Step 4, the allocation of these costs (some of which are joint) would be made to the various rating periods on the basis of appropriate criteria. Step 5 would involve putting these various costs together, for each rating period, to devise a cost-based rate for each period; and finally, these preliminary rates would be adjusted into a practical set of proposals which blend these rates with other pertinent regulatory standards, in the light of practical metering capabilities (the subject of Topic 7). It is not the intention of the foregoing description to foreclose consideration of alternative pricing methods. There should be an explicit consideration, for example, at least in principle, of the possibility of basing rates on short-run incremental costs.

Topic 4 is described in the Plan of Study as:

Topic 4 Costing for Peak-Load Pricing

The actual application of the methodology which is to be described in the working paper prepared in Topic 1.3 would require cost data which would be applicable to particular utility systems. A great deal of work with company data drawn from a number of cooperating utilities will be required.

The problem in this area would be, first, to determine what companies would be most useful for inclusion in a detailed cost analysis. The criterion here is not randomness but rather the inclusion of a diversity of problems. A company's willingness to make a great deal of data available is of course the first essential, but thereafter companies should be chosen with a view to covering the major characteristics which are thought to entail different cost structures. These might be summer vs. winter peaking (c.f. Topic 6.1), connection to a power pool, predominance of hydro capacity, etc. Public/private differences may also need to be taken into account. A first topic (4.1) would be to identify the companies willing to participate and those who have usable data, and to make the selection of participating companies, using criteria discussed above.

Topic 4.2 consists of the field work utilizing actual cost data. Using the approach developed in Topic 1.3, company cost studies would be performed. As is clear from work already performed the application of methodology derived from costing theory raises problems of implementation which can require the rethinking of tentative solutions. Moreover, the varying company situations may pose issues not foreseen in the theoretical stage. Consequently, it is essential to the full development of a costing program to engage in this "field work."

A further problem in developing costs is that if a change in rate form is contemplated, <u>demand</u> responses of consumers <u>may</u> change the <u>cost</u> structure. This makes it crucial that the knowledge to be gained about elasticity responses (Topics 2.1 and 2.2), associated with the introduction of different rate structures, be integrated into the costing analysis, to the extent possible, and that sensitivity analyses be performed as to the possible size of cost changes resulting from rate changes. Involved here is the potential of peak shifting (c.f. Topic 6.1) and of revenue erosion.

The results of the first two topics in this section would form the basis of a report (Topic 4.3) which would review the results of cost analyses comparatively to determine what modifications to the theoretical costing analysis are indicated to yield a "de-bugged" methodology.

Finally, (Topic 4.4) while most of the major companies collect cost data for purposes of accounting, budgeting, planning and load management, and some of this will have direct application, there are likely to be definitional inconsistencies and actual gaps in the data, and as work proceeds on earlier phases of the topic, supplementary data collection requirements may become apparent. The completion of Topic 4 should make available a practical costing methodology which could undergird a peak-load pricing approach.

Topic 5 is described in the Plan of Study as:

Topic 5 Ratemaking

Topic 1 will include an evaluation of the pros and cons of various ratemaking principles, in relation to peak-load pricing. Here the concern is primarily with the application of these principles. The resolution of issues concerning pricing which emphasizes time of use, or control of consumption devices, or long-run incremental costs rather than average costs, or ratchets in rates, or seasonal rate possibilities or penalty pricing does not eliminate the need for study of the appropriate format of individual rates. The declining block rate form, the flat rate form, and multipart rate form are not substitutes for the proposals discussed herein, but are means of reflecting the decisions which may result. Therefore, to respond to Resolution No. 9 with regard to appropriate rate structures and to meet the other purposes of this study, it is necessary to analyze (Topic 5.1) the theoretical and practical benefits of various rate forms as a means of applying to the customer the recommended principles. This study would take the form of answering the question, "Assuming that each type of pricing considered herein above is found feasible and productive of net benefits, what would be the advantages of expressing those pricing concepts in various rate forms?"

Ratemaking on the basis of more traditional principles has been put into acceptable rate forms many times, and no "how to do it" development is here needed. Peak-load-pricing rates, however, present a more difficult problem. The process described in Topic 4 should yield unit demand and energy costs applicable to various seasons of the year and to various times of day, for several different types of representative companies. Given the cost circumstances of the industry, these unit costs are the point from which one must depart in making rates, using as guides such information on demand responses as will at that point in time be available. This translation of costs into rates is not a simple process, even assuming adequate measurement technology were available. Various constraints need to be introduced at this point. This first and most significant constraint will be, of course, that the total revenues achievable from theoretically applied rates be compatible with regulatory practice. When use of pricing derived from marginal costs is deemed appropriate, there is a body of economic theory on how this should be done, which involves setting the most elastic demands closest to marginal cost (c.f. Topic 2.1). This body of theory would be examined both for its conceptual merits and also as to its applicability to such data as will have been developed in Topic 4. A report (Topic 5.2) will be prepared on the feasibility of making rates based on these economic principles which are consistent with other regulatory criteria (c.f. Topic 1). This will include also an examination of other criteria (such as "social justice") in terms of their potential incorporation into rate structures.

A further problem has already emerged in considering the application of rates which vary by time of day to small commercial and residential consumers. The metering technology needed or available for this will be further investigated under Topic 7. But as work proceeds on Topics 3 and 5, first cuts at likely rate forms will be developed, and it is important that the parameters to be measured as inputs to the rates be communicated to the people concerned with the technology. This effort assumes (without asserting) that the necessary metering effort is considered cost justified.

A series of working conferences to suggest and explore rate forms and data needed for those forms should be conducted and should include participation of those concerned with metering technology. Preparatory work for these working conferences could proceed immediately (Topic 5.3).

A final undertaking in this section (Topic 5.4) would address the problem of how to proceed with peak-load pricing without adding significantly to current metering costs since one obvious possibility is that the costs of new meters for smaller consumers may well exceed the benefits under present metering technology. If there is strong reason to suppose this to be true, a methodology for dealing with implementation of peak-load pricing without advanced metering (using meters now available) will be proposed. This would be done in conjunction with Topic 3.5.

Dr. Morton's material is responsive to the requirements of Topic 1, Topic 4, and Topic 5. His findings, as reflected in this document, will be weighed by the Project Committee in reaching its conclusions. Many of the issues in the rate design study are controversial, in some cases data are lacking, and in certain instances value judgments are necessary. Therefore the reader is cautioned to make a careful assessment of Dr. Morton's findings and to consider other sources of information as well.

NOTICE

CONTENTS

SECTION 1
GENERAL EVALUATION

These studies are aimed to show (1) how the different costs of time differentiated services can be ascertained and (2) how such costs can be used to make time differentiated rates. These two objectives were assigned to Ebasco Services Inc., and these studies were aimed to fulfill them. However, Ebasco shows that costs and rates are not necessarily related one to one because time differentiated rates, or any other rates for that matter, are determined not by relative costs alone but by other objectives. Nevertheless, the purpose of the study was to show how "cost-determined" time differentiated rates could be used to improve the load factor and/or to give the "right" price signals to consumers of electric power.

Within the ambit of these basic assumptions, these studies are well done and can serve as a guide to utilities, commissions, and consumers, who accept in large part these traditional assumptions. The basic Ebasco theory is set forth in 1.3 and consistently carried out in the other studies. All studies are, on the whole, free from dogmatism, and the various statements of fact and conclusions about policy are appropriately circumscribed and limited in their application.

It is, of course, theoretically and practically possible to ascertain the total cost of all the kWh produced in a given year and hence the average undifferentiated cost per kWh. If the quantities are definitely specified, it is also possible to ascertain the short-run and long-run marginal costs of an incremental supply. Rates that will yield revenues equal to average costs will then constitute the revenue requirements. Rates equal to the incremental costs will cover the costs of the incremental supply but, at present, will produce revenues exceeding the cost of the new total supply. Accordingly, many advocates of marginal cost pricing would reduce such rates below marginal costs by use of the inverse elasticity rule. Marginal cost pricing therefore, in application, is not marginal cost pricing but pricing that yields revenue requirements determined by average embedded costs. Accordingly, Ebasco finds--and, I think, correctly--that the "end result" of marginal cost pricing modified by the rule of the "second best" will be approximately the same as that under embedded average cost pricing. This result is, however, dependent upon the methods of computation, which can be varied in practice to yield whatever "end result" is desired.

It is not, however, total revenue requirements that are at issue in these studies of time differentiated costs and time differentiated prices. The issue is rather whether it is theoretically and actually possible to differentiate costs by time periods and whether rates should follow such costs.

Ebasco does not pretend to be following the economic theory of costing and pricing but is aiming, rather, at results that will satisfy the various criteria used in ratemaking.

All the basic difficulties of the studies of time differentiated costs arise from the limitations placed upon the students by their assignment. That assignment was to find the costs of producing a kWh of electricity at different times of the day and year and to design rates based upon these costs.

In the opinion of this writer this task is impossible. In a quotation from the Pennsylvania Public Utility Commission, Ebasco shows that these costs at different times of the day and season are joint costs produced by the plant in existence at each time. Despite any claims to the contrary, I believe it is well established in economic analysis that it is impossible to find the "in fact" cost of any one of a number of joint products. The task imposed upon the contractors by NARUC is therefore a theoretical impossibility. It has accordingly been construed by Ebasco to require them to make the best pragmatic estimates in accordance with costing tradition. Their rating periods, which differ from company to company, are based upon their estimates and experience and do not attempt to achieve what is theoretically impossible, a task which some analysts might seek to impose upon them. However, the resulting difference in time differentiated costs is largely a consequence of their "arbitrary" assumptions about the allocation of capacity costs. These costs could vary by as much as 50%, depending upon the assumptions regarding methods of allocation. If all capacity costs are assigned to the peak and none to off-peak, the time differentiated costs will vary greatly. If other allocations are made, this hiatus can be reduced, or even eliminated, by arbitrary allocations. We must conclude therefore that it is theoretically impossible to find the cost of producing any joint product, and that if peak and off-peak output is considered to be a joint product of a given plant, it is impossible to know the peak and off-peak costs except by making arbitrary assumptions about the allocation of capacity costs. Ebasco has made such assumptions as will eliminate the free ride to off-peak users, but in doing so has opened itself to criticisms of its particular allocations under the BIP method.

The economic theory that price equals marginal cost applies to products not produced jointly. But there is no economic analysis that shows how to find the cost of any product produced jointly with other products. There is no economic theory showing how to find the cost of producing a pound of ham, of bacon, of pork chops, of pigs' feet, or of pig bristles from the same hog or hogs. Or to use an illustration of seasonal pricing: A hotel room at Lake Tahoe is priced higher in summer than in winter, and a hotel room in Florida is priced higher in winter than in summer. The capital costs do not vary in this inverse fashion, and if hotel owners came under regulation, no reasonable allocation of fixed costs such as depreciation, interest, property taxes, and so forth to determine costs in January and July would make the seasonal prices charged for rooms vary with such "allocated costs." Prices would be determined by the value of service, elasticity of demand, or "whatever the traffic would bear," however it be called, and not by allocated costs. Nor does the "marginal" capital cost vary with the weather. These prices, under competition, would maximize net revenues. Moreover, under competition, the off-peak users of hotel rooms would get a lower price but not a free ride.

The attempt to find the cost of gas produced jointly with oil was made by the Federal Power Commission in the original cost-of-service studies for gas producers.

Casing-head gas is produced jointly with oil and some other nonuseful products. Before the pipelines this natural gas had little value and was used for carbon black or flared. Soon it had a value for fuel and came under FPC regulation. The cost of producing this joint product was then evaluated. Were costs to be calculated by treating the BTUs of oil and gas as equivalents, or by allocating exploration and production costs in proportion to the relative market prices of gas and oil? If the latter, then allocated costs became a function of market price but did not determine market price. By retrospective inference, cost was inferred from price and not price from costs. As the market price of gas rose, this method of reasoning proved that the "cost" of gas had also risen.

Those who find that off-peak capacity costs are less per kWh than on-peak capacity costs of electricity are using a similar type of retrospective inference. They find that the value of service off peak is less than that on peak and hence infer that the cost of service off peak must also be less than its value on peak. They then allocate more capacity costs to the peak and less to the off-peak and thus justify their conclusions and produce a "reasonable" cost for each period that enables them to justify the peak and off-peak rates. They can then improve the load factor and maximize net revenues. That this method has been widely used does not indicate that it is rational or that it is the only way to find a just and reasonable price.

This brief analysis indicates two things: (1) that there is no rational way to find the capacity cost per kWh for on- and off-peak use of production facilities except by use of arbitrary allocation procedures that must be justified on other grounds and (2) that consequently a price equal to this allocated cost is an arbitrary price. The price signal is therefore also an arbitrary signal, which may or may not happen to produce the desired allocation of resources.

Ebasco's analysis of time differentiated costs, based on an acceptance of the view that there is some pragmatic method that produces the best results, is therefore not supported by an economic analysis of the pricing of joint products. Unlike the marginal theory that allocates all capacity costs to the peak and none to the off-peak, the Ebasco method, however, produces an end result devoid of the free ride provided for off-peak users by the 100% allocation of capacity costs to the peak and thus more nearly approximates the results that would obtain by simulation of pricing in the free competitive market. In that market, competition would most likely result in all users of a commodity or service paying a minimum of variable costs with such additional contributions to capacity costs as the value of the service would bear. The total returns would, however, remain reasonable because of competition of producers of the service.

In order to spare us from having no guide for pricing at all, it may be suggested briefly at this point that there is an economic guide to utility prices.

Utility prices should provide average revenues to cover average costs of producing the desired output at a given time. The aim of management and of the regulatory authorities should be to provide a price structure so as to minimize the long-run average cost per kWh of producing whatever output is desired at prices that cover all costs. A utility with a high load factor will need less capacity and hence will have less capacity costs per kWh than one with a low load factor. Accordingly, one of the aims of efficiency should be to improve the load factor insofar as this can be done by the voluntary, or price-induced, action of users. An improvement in the load factor reduces the peak below what it might otherwise be and hence reduces the need for plant expansion. More kWh on and off peak together are produced with lower costs per average kWh. It follows then that the economic aim of regulation is to produce the output at lowest average costs and that load management and time differentiated rates should be used insofar as they contribute to this economic end. The structure of rates will thus be determined by the efficiency objective and not by some ill-fancied time differentiated cost per kWh diurnally and seasonally.

Unfair discrimination will be prevented by making the rate structure simulate that which would be produced in the competitive market without an attempt to "prove" that costs per kWh differ by time of day or season, which, as we have shown, depend either on the assumption of the free ride or on arbitrary allocations of capacity costs.

Pricing for load management follows from the efficiency objective and relative prices on and off peak will be fair so long as they simulate those that would prevail in the competitive market. We do not allege that a butcher who charges more for steak than for hamburger is unfair or discriminatory, or that the price of bacon and ham is unfair if it exceeds the average cost of producing the whole hog. Nor do we believe that winter and summer seasonal room rates are unfair or unreasonable in the hotel business unless they are justified by some manipulated determination of capacity costs. Restaurants, airlines, and theatres also charge different prices at different times of the day or season. None of these needs to justify such differentiation by allocated time differentiated cost studies. Such peak and off-peak rates are consequently a product of the free competitive market.

We need therefore to rid ourselves of the preconceptions that cannot be justified either by correct theory or by fact, that the cost of producing a joint product can be found and that such an alleged allocated cost is the "right price," which should be made effective regardless of its effects on the load factor or economic efficiency. We can then pursue the objective of efficiency by designing rates to improve the load factor and to reduce the new capacity required in the long run to produce the desired output at an average price that covers average costs. If marginal costs of new plant are rising, then marginal costs will continuously exceed average costs. If marginal costs of new plant are constant, then marginal costs and average costs will tend to coincide. If marginal costs of new plant are falling, then marginal costs will continuously be below average costs, as they were, generally, prior to the late 1960s.

The cost-of-service analysis presented by Ebasco can readily be made consistent with these principles merely by changing its emphasis on the cost determination of time differentiated rates. Indeed, Ebasco, being realistic, says (Topic 5, page 18) that its proposed rates are for the purpose of gaining "knowledge of the customer's behavior and its effect on the utility's system and capacity requirements. For that purpose, rates do not need to be cost based." It then says it would seek "the minimum ratio between peak and off-peak prices which will cause customers to shift load" and its effects. Ebasco's objective when dealing with ratemaking is therefore free from the encumbrance placed by allocated costs on rate structures, and its proposed rates do not follow "costs." Why then should we not move directly toward the objective of efficiency, and be guided by simulation of pricing in the competitive market to achieve fairness?

Ebasco also emphasizes that the rating periods for peak, intermediate, and off-peak use cannot be determined independently of the experience of each company. It follows that the ratemaking procedure, insofar as it concerns time differentiated rates, should not proceed from the theoretically unsupportable task of finding time differentiated costs, but should proceed directly toward a rate structure that will in the long run improve the load factor, increase efficiency as measured by average costs per kWh, and thus simulate the results that would be obtained in the competitive market.

Such a procedure would still require the usual cost-of-service studies, which aim to find: (1) the variable costs per kWh depending upon the kind of generating equipment used, the type of fuel and its costs, and any other factors affecting variable costs; and (2) the amount and kind of plant and equipment devoted to each class of service, industrial, residential, and commercial. Such studies would show what specific costs can be attributed to each class of customers. The cost of serving industrials would not include the distribution and customer costs needed only to serve the residential users, whereas the costs of serving small industrials and commercial users might contain other elements not needed for large industrials, and so forth, as has already been noted in the cost-of-service manuals. What would not, however, be needed is an attempt to "allocate" the bulk of production property available for usage at all times of the day and year to producing kWh for all peak and off-peak customers. The distinction between peak and off-peak rates would be determined primarily by the effects on load. Marginal costs would determine the choice of new construction projects because each new decision of management regarding the type of generation, transmission, and distribution equipment would continue to be determined as heretofore by weighing the various methods of improving or maintaining efficiency in the long run. Each new decision would thus be a marginal decision.

What Ebasco has tried to do and, in my view, has accomplished very well is to seek to achieve the above objectives while operating through the route of time differentiated costing. Those who do not agree with Ebasco's results can readily insist that their own theories and purposes would have produced a different allocation of capacity costs and hence a different cost of service, and no one can gainsay it. There are in truth as many possible allocations of capacity costs between peak and intermediate and off-peak services as there are numbers, and those who make them can always produce a rationalization for their use. Theoretically all such allocations are arbitrary and do not produce a true "cost" of service at any minute or hour of the day or year.

Regulatory bodies must therefore continue to differentiate between the plant used for different classes of customers, but they should abandon the effort to find a time differentiated capacity cost for plant jointly used and proceed directly to the objective of load management and the use of time differentiated rates having a lower limit of variable costs and an upper limit of value of service within the constraint of total revenues equivalent to total costs and hence to average costs per kWh.

This would mean the abandonment of the many complex time differentiated costs of service, whether based on average costs for a past test year, average costs for a projected test year, marginal costs for a specified quantity for a number of future years, or any variation thereof. All such studies based upon judgmental allocation of capacity costs would become supererogatory.

SECTION 2

TOPIC 1.3: PRICING APPROACHES

We must agree with Ebasco's propositions on page 6 that the peak-load pricing objectives, though apparently different for regulators, customers, and utilities, all have a common basis in the desire to improve the load factor. Page 7 shows that the demand (kW) growth has recently exceeded the growth in kWh. This means that the average capacity cost per kWh has risen and that improvement in the load factor will tend to reduce costs.

Peak-load pricing (PLP) is therefore not a primary objective as such but merely a means to an end--improvement in the load factor and reduction in costs per kWh. Ebasco makes these propositions clear on pages 7 and 8.

On page 9 it is pointed out that the peak-load pricing policy can be pursued independently of the method of costing and need not be associated with long-run marginal costing. I would add what Ebasco does not, that it need not be associated, either, with average costing of any kind that requires allocation of capacity costs. Peak-load pricing policy is therefore independent of any costing methods that require allocation of joint costs. It may be pursued whenever and wherever it causes a shift in the load factor that will reduce plant requirements and thereby lower long-run average costs per kWh.

In consideration of the ratemaking process (page 13) Ebasco indicates that rate design is prompted not solely by costs but also by other considerations including value of service, ability to pay, equity, and so forth, and on page 14 states, quite accurately, that there is "no universally used and accepted single based allocation of cost basis incorporated in rate structures." Ebasco nevertheless appears to indicate that "great strides have been made toward class cost of service determinations" but does not sufficiently emphasize the difference between the attribution of some known costs attributable to certain services, which can be correct both in theory and in practice, and the allocation of joint capacity costs to different times of the day and seasons of the year, which is incorrect in theory and regarding which wide disparities exist in practice.

This discrepancy is characteristic of the ambivalence of Ebasco's study with respect to crucial theoretical issues. Ebasco does not resolve these issues but rather relies upon knowledge and experience to provide solutions that are pragmatically useful and conventionally acceptable. As I have indicated, this position logically follows from the task of finding costs that are useful for time-of-day pricing, and any defects in Ebasco's analysis are therefore correctly attributable to the assignment rather than to any unwillingness to face the theoretical problem of the relation between rates and costs that are in significant part joint costs. Reliance upon the FPC Uniform System of Accounts or upon the NARUC Cost Allocation Manual does not resolve these issues.

The theoretical difficulty created by the allocation of joint costs could be neglected if it were merely an academic question. However, it is of great practical import in ratemaking because different analysts make different allocations, which can be made to vary from zero to any amount between zero and 100%.

On page 15 Ebasco indicates that customers, utilities, and commissions are moving to cost based rate design. They should not merely indicate this tendency but emphasize its many limitations and its inherent theoretical fallacies, which no pragmatic adjustment can resolve and which will continue to plague rate case hearings as long as it persists. The fact that certain nonrational procedures have been followed does not justify their continuance or justify the failure to state clearly their inherent errors and limitations.

After indicating that social and other considerations affect rates (pages 16 and 17), Ebasco quotes the Pennsylvania Public

Utilities Commission to the effect that: "It is not possible to determine precisely the cost of service, for costs involved are largely joint costs" (page 18). But it does not make any significant attempt to separate out the specifically attributable costs from the joint costs for the purpose of determining the cost of service at different times of the day or year. This is the crucial issue in time differentiated rates purportedly based on differential costs.

This basic inconsistency thrust upon Ebasco by its assignment does not, however, seriously impede its efforts to arrive at a result that will most likely be fair and reasonable to the parties concerned and that will help achieve its objectives. But the reason is that its allocation of joint costs appears to be determined retrospectively by inferring from the desired price to the allocated cost of service, rather than from a time differentiated cost of service to a time differentiated rate.

We must agree with Ebasco (page 23) that the traditional ratemaking process is able to achieve peak-load pricing without the adoption of marginal cost pricing. But this writer would emphasize that all costing methods that include costing of about 50% of total joint costs have serious defects for ratemaking purposes in addition to their inherent intellectual deficiencies. Capacity costs off peak may be allocated a weight of zero by some but are assigned 21% to 24% by Ebasco in Table 2, page 43. The difference in rates between a zero and even a 20% assignment of capacity costs off peak would be about 10%. Whether a 10% difference between peak and off-peak rates would be sufficient to cause a desired shift in load or whether the differential should be greater or less must be determined by experiment.

However, as long as rates are purportedly "cost based," the difference in such "allocated costs" will be determinative for time differentiated rate differences regardless of their effectiveness in improving the load factor. If, on the other hand, the main aim is to improve the load factor, then these rates must be judged by their effectiveness in changing the proportions of peak and off-peak usage by the amount that will effectively reduce the need for new plant and the long-run cost of service per kWh. The rate differential to accomplish this may be greater or less than the differences in allocated costs. Ebasco recognizes that other load management devices such as the demand ratchet and interruptible service for some industrials may be used. Ebasco emphasizes also that probable savings due to peak-load pricing must be weighed against the cost of time-of-day metering for residential customers and the possibility of producing the "needle peak," which would result in a high level of capacity and a low level of kWh usage, higher average costs per kWh, and, in the short run, impairment of revenues.

Ebasco presents the numerous factors to be taken into account in peak-load pricing but generally relates these factors to the determination of seasonal and time of day costs and then, indirectly, to rates. On page 29 Ebasco says that "only 45% of private electric utility plant in service was in the production function at year end 1975." It is therefore primarily the cost of this 45% of the total plant that they are allocating to peak, intermediate, and off-peak periods (BIP).

The purpose of the BIP rating classification, instead of the more simple peak and off-peak dichotomy, is that it enables costs to be differentiated for different loads. In theory there could be two, three, or more rating periods, depending upon the practicability of differentiating costs between different hours of the day. Inasmuch as the attempt to find capacity costs for a joint output is inherently fallacious, it follows that if the joint output were produced with a 100% load factor, then it would not be a different product at any hour and average costs would take the place of allocated joint costs for different rating periods.

It would therefore be more fruitful to discard the inherently impossible task of allocating joint capacity costs and to proceed to study the load curve for a particular utility and to make an estimate of the capacity savings if the load factor were raised. Once that estimate was made, then rates, ratchets, and interruptible rates could be so designed as to shift usage from peak to intermediate and off-peak periods. The rates would then be made to achieve this objective rather than to conform to some "allocated cost" for each hour of the day or rating period.

Occam's razor should be used on "allocated time differentiated costs" as a superfluous entity in the determination of time differentiated rates. Time-rate differentiation as well as demand ratchets and interruptible service could then be used for load management with the ultimate goal of reducing required capacity and hence long-run cost per kWh.

For this purpose the excellent analysis of the fixed and variable cost components of peaking, intermediate, and base-load units shown in Table 1, page 42, and the cost assignments by rating periods on pages 43 and 44 provide useful information as to the probable effects of changes in load characteristics. They can therefore be useful for load management in spite of their doubtful validity for ratemaking.

Section IV, beginning with page 45, deals with marginal cost pricing. In the section dealing with the history of marginal costing, Ebasco contends that in Ontario the "proper price signals" overpriced the energy component and underpriced the demand components of costs. They conclude that this is an error and that understatement of demand costs is inconsistent with the objectives of peak-load pricing. This observation makes it clear that the real objective of rate policy is to achieve an improvement of the load factor and not to achieve a "right price," which is not "right" in any objective sense but which accords with the particular allocations made on a nonrational basis by the costing expert. Although Ebasco therefore appears to be correct in practice, its theory that the time differentiated rate structure should be based on costs leads to different results depending upon the person who uses it.

Ebasco again is correct in that it judges the adequacy of the costing process by its effect on the rate structure and ultimately on the load factor. Ebasco achieves a presumably "correct" result by a roundabout process, which same process used with different allocations leads others to an "incorrect" result. The correct price ought to be defined as the price that leads objectively to the correct effect on the load factor--not one that satisfies the best-judgment cost objective of the user and is therefore largely subjective.

Ebasco concludes that both the wholesale marginal costing by Ontario and TVA and the current marginal cost studies have had the aim of energy conservation rather than load factor improvement and that this emphasis on energy conservation leads to higher unit cost and hence higher rate levels, which is contradictory to PLP objectives (second paragraph, page 47). Ebasco accordingly judges the correctness of the "costing" method by the end result on rate levels and load factors, thereby reaffirming that the "costing" methods are a consequence of the pricing and load factor objectives rather than the reverse.

In discussing marginal cost capacity assignment, page 48 and following pages, Ebasco opposes the free ride for use of capacity by off-peak users. It points out that "regulators have accepted the premise that inequity would result from allowing the off-peak customer to use a substantial portion of the output of the plant capacity provided by the payments of all firm service customers without making a contribution to the support of that plant" (third paragraph, page 48). This writer agrees with this view but would suggest that instead of relying upon such nonrational grounds as custom, "ethics," or the past practice of regulators, which by itself has no probative value, the free ride be exorcised from ratemaking not on the common hunch that it is intrinsically wrong but on the rational ground that apparently underlies this hunch, that it does not exist in the free competitive market for other commodities or services.

I suggest therefore that regulators consciously accept the criterion that the correct price for peak and off-peak utility services is one that simulates the free market price and achieves the objectives of load management. Acceptance of this criterion would require deliberate rejection both of the marginalist theory that all capacity costs be charged to the peak users and of the nonmarginalist theory that subjective allocations of capacity costs be used that appear to provide the correct effect on the load factor. Ebasco appears to agree with this criterion implicitly if not explicitly in its conclusion, page 53.

I must, however, dissent from the view expressed by Ebasco that marginal cost pricing somehow leads to emphasis on energy economy rather than on plant economy. Marginal cost pricing by making capital a free good to the off-peak user is aimed to increase its off-peak use and thus to raise the load factor. The free ride is plant saving, not energy saving. Indeed, because the free ride logically pursued would push off-peak rates down to variable costs, mostly fuel costs, it would encourage energy consumption. Insofar as it transferred usage from high-heat-rate sources during peak to base-load, low-heat-rate generation, it would temporarily save some energy. However, in the long run, when plant capacity was adjusted to serve the new load factor, these low off-peak rates might lead to increased energy use and increased fuel requirements.

It is proper, therefore, to insist that the purpose of peak-load pricing is to correct the load factor and not primarily to reduce fuel consumption, which in the long run will be governed by the overall height of utility rates and elasticity of demand. These factors will remain operative regardless of the type of "costing" procedures used for allocation of that part of cost that is joint. These factors are all "arbitrary" in terms of logic; in human terms they are "judgmental"--based upon "experience" or some form of ethical or social objective.

Marginal costing must remain the guide for additions to plant capacity, whereas average costs before and after the addition of new capacity must remain the guide to revenue requirements and the level of rates. Rate structures must be governed by their ultimate effect on plant capacity and average cost per kWh.

In Section V Ebasco has carefully shown the various rate forms that could be used for peak-load pricing. These rate forms appear to take into account deviations in rate structure, but their serviceability must depend upon their application to each utility and its customers, and the incremental cost of time-of-day metering.

SECTION 3

TOPIC 4: COSTING FOR PEAK LOAD-PRICING

We must agree with "Ebasco's position that peak load pricing, whether seasonal or time of day differentiated, can be accomplished by use of both embedded and marginal costing approaches" (page 4). But this writer would modify it by saying that PLP can be accomplished without any reference to allocated peak and off-peak costs. The only cost data needed are long-run average costs of total output before and after PLP.

We must also agree that PLP produces price signals aimed to reduce the peak load but does not serve the objective of energy conservation (page 6).

For the reasons already elaborated, we must disagree with the proposition on page 7 that "the first step in the implementation of PLP regardless of whether based on average or marginal costs requires that costs be defined and differentiated by seasons and/or time of day." Such time differentiated costs are not needed for PLP, and such "in fact" costs are theoretically impossible and are achieved only through arbitrary allocations of joint production costs.

This erroneous postulate leads to the next erroneous statement (page 8), that "periods of greater system load have generally associated with them a greater portion of fixed costs per unit of load." This statement is true only because costing experts make this association by their arbitrary allocations. It is not, however, true that a given fixed plant producing at a high system load has a higher unit cost than one producing at a lower load. Precisely the contrary is true. Given the dollar value of total plant producing at 100% of capacity, cost per kWh will be smaller than if that same plant is producing at, say, 50% of capacity.

In its Annual Report for 1976, Duke Power Company shows that the following uses were made of the revenue dollar.

Fuel Costs	33%
Depreciation	10%
Taxes	21%
Wages, Benefits	6%
Maintenance Materials, Other	9%
Interest and Preferred Dividends	11%
Earnings for Common Stock	10%

The items fixed by the total capital--depreciation, taxes, and return--add up to total fixed charges of 52%. Because these items are fixed, their distribution over a smaller output would produce a higher kWh cost than their distribution over a larger output.

On the other hand we must agree with the next proposition of Ebasco on page 8, that "periods of greater system load have generally associated with them a greater portion of variable costs per unit of consumption." Fuel costs obviously vary in the same direction as output, and if the larger output requires use of more expensive fuels or of generators with a lower heat rate, the variable cost will be greater per unit of output. However, if the plant is designed so that the high consumption can be met by base-load plants, it does not follow that unit fuel costs need be higher at peak than off peak, particularly, as Ebasco shows, if hydro is used to meet the peak.

The following propositions are designed to state in simplfied form the relations between total costs, various outputs, price, and load factor.

1. With a 100% load factor, total costs/total kWh equal costs per kWh. There is no peak and off-peak pricing,

the price of each kWh is the same, and the effect of price on the load factor is zero.

2. With <u>any</u> load factor <u>less than 100%</u>, long-run average cost will be higher than under 1., and if all prices are kept equal to average cost, the effect of their rate design on the load factor will remain zero.

3. If peak and off-peak price differentiation is desired, the minimum price should be the variable cost per kWh and the maximum price would be determined by value of service. However, the allocated cost per kWh would be determined by total variable cost/kWh plus the total allocated fixed capacity cost/kWh.

4. It follows that if 100% of capacity costs are allocated to the peak and zero costs are allocated to the off-peak, then total peak costs will be higher than off-peak costs.

5. If less than 100% of capacity costs are allocated to the peak, then some percent must be allocated to the off-peak, and the capacity cost per kWh on and off peak will depend upon the percentages of the total allocated to each.

6. Accordingly, under the 100% allocation to peak, Duke's approximately 50% of the revenue dollar would all be raised by pricing peak use above average costs and off-peak use below average costs. But such pricing above or below average costs should not be construed to prove that "in fact" costs are truly shown by the respective peak and off-peak rates.

Pricing serves the purposes of load management and, insofar as it happens to be correctly estimated, will in the long run reduce the total cost of capacity and hence the cost per kWh. On page 11, Duke has charted two lines: a black line, always above the red line, showing the load forecast without load management; and a red line, always lower, showing the load forecast with load management. Duke estimates that until 1990 there will be a reduction in the growth of the peak and of the amount of generating capability required to serve that peak.

Duke is therefore following functional load management; it does not price according to present load factors alone but instead prices so as to produce the kind of load factor that it believes is possible and desirable and that will produce the kWh its customers desire at the lowest average cost. This policy will benefit both consumers and shareowners and can therefore be pursued without a conflict of interest between these two groups, although some consumers off peak and some marginal cost theorists may come in with so-called cost allocations designed to serve their special interests.

In order to follow a policy of load management with the aid of peak-load pricing it will still be necessary to identify the periods of lesser and greater loads and the desirability of shifting the load from one period of the day to another or from one season to another. Accordingly much the same kind of study made by Ebasco to implement their "cost" study is still useful and appropriate to implement a load management policy by time differentiated rates. For this purpose it will therefore be necessary to identify the peak, intermediate, or any other periods appropriate to a utility operating in a given area. Such identification will, however, have the purpose not of "costing" but of promoting improvement in the load (see page 9).

The functionalization and classification of plant in service (beginning on page 13) will remain necessary for determination of the costs of serving different classes of customers but will become unnecessary for the purpose of ascertaining time differentiated costs and peak and off-peak rates.

The allocation of costs to rating periods (beginning on page 83), while providing some information about the probabilities of shifting loads, is unnecessary for the development of peak-load pricing, and because it depends upon arbitrary allocations, it will lead to extensive controversy between various arbitrary cost allocators who believe that their own allocation and theirs only has the merit of eternal truth. Like all nonrational values, the merits of the various cost allocations can never be resolved, and discussion of them merely engages the time of the companies and the commissions and delays the solution of rate cases.

We must therefore agree with Ebasco when it says on page 112 that the cost-of-service studies in the past have not been translated directly into rates and that present concern appears to be about the relative rates of return being earned on the various classes of service. These rates can be computed without reference to a differentiation between the cost per kWh at 2 p.m. and 2 a.m. Time differentiation of costs is not necessary for purposes of finding the return on residential, commercial, and industrial services and is clearly impossible, as we have shown, except by use of arbitrary cost allocations.

For that reason we must agree with Ebasco's statement on page 112 that "many of the economic objectives of peak load pricing could have been achieved swiftly and within the current regulatory framework." However, this writer would make the process completely free from the encumbrances created by the traditional belief that PLP must be justified by allocated cost-of-service studies.

Naturally, this writer also agrees with Ebasco (page 113) that "the premise that peak load pricing must be based exclusively on marginal costs is absurd. . ."

We must also agree that Ebasco is fully consistent in its position when it says: "Ideally we would like to see a production planning period long enough to represent the long-run mix of future generating units." Such an estimate must be made whenever any utility plans a construction program. Likewise it must also estimate the probable effects of its rate structure on the load factor and the amount and type of plant required. All such estimates of future construction costs and prices and of availability of fuels and other materials may have a large element of error, but this error is unavoidable in any action taken for the future so long as man does not have the omniscience of the Deity. Formulas postulating such foresight are merely intellectual diversions practiced by those unable or unwilling to meet the problems of the day.

The number and length of rating periods required to estimate costs at particular times of day or seasons is, as Ebasco indicates in its studies, a function of the type of load that each utility has and of the means of meeting the peak and off-peak demand. Ebasco seeks to find differential time related costs in three periods: peak, intermediate, and off-peak. In some cases only two periods are used. However, in theory there could be as many periods as there are hours of the day and seasons of the year. The issue is truly not how many different time differentiated costs should be measured but what loads can be shifted from one period to the other so as to improve the load factor and reduce the overall cost per kWh. By using such a more objective criterion in place of an "ethical" allocation based upon an arbitrary computation of costs, commissions can have recourse to the competitive model of pricing. Use of that model, by itself, will not provide quantitative knowledge of the effects of load shifting but will enable rates to be justified by their ultimate long-run cost effects and by their conformity to the practice of the competitive society, in which prices are not set by allocated costs or by free rides for any group of buyers.

SECTION 4

TOPIC 5: RATEMAKING

The purpose of this report is stated to be: "to present rate forms developed from the different costs of service studies prepared by Ebasco" (page 1). And on page 2 Ebasco states: "We will now, in this report, take the results of these cost studies and translate them into rate forms for the pricing of the different services." But on page 4 it is shown that rate design does not simply follow differential costs but also follows some eight other objectives, including "the control of the relative uses of alternative types of service (on-peak versus off-peak)." And on page 5 it is said that peak load pricing is, then, "an attempt to price the use of the service in a more fair and equitable manner than present methodologies" and that the pricing format will reflect differences in costs. Pricing by "cost differentials" is accordingly considered "ethical" and able to give the "proper price signals to produce the best allocation of resources."

After this obeisance to "cost," Ebasco emphasizes that it may "compromise the strict adherence to cost" for practical reasons. This, however, is clearly not an abandonment of the cost-equals-price objective.

Ebasco then discusses methods of dealing with the windfall profits produced by making prices equal to marginal costs. It agrees that any load shifting would be from the high-price to the low-price areas but finds also that the industry does not have the knowledge about demand elasticities that would enable it to predict the precise shift.

So far so good. Cost based rates appear to be the objective, and load shifting appears to be merely coincidental. However, on page 18 Ebasco says that in order to obtain knowledge of the customer's behavior, rates do not need to be cost based.

For this purpose, it would be meet to inquire as to (1) the minimum ratio between peak and off-peak prices that will cause a shift in load; (2) the length of the rating period that will cause customers to shift load without creating a new peak; and (3) which customers shift and where the load goes. Ebasco correctly asserts that such an experiment in load shifting should not be constrained by adherence to the price-equals-cost criterion. However, Ebasco does not make it clear whether it believes that the main criterion for rate design should be (1) to make differential rates equal to differential costs, regardless of the effect on load, or (2) to minimize time-of-use disparities and thus reduce costs in the long run. Because the costs in different rating periods turn out to be in significant part a consequence of methods of allocation, the cost criterion and the "ethical" consideration should in my view be cast aside for the pursuit of the desired load objective. Ebasco is profoundly conscious of the load management objective but appears to be bound by the assignment that that objective must be pursued only indirectly, by demonstrating that differential costs will produce differential rates, which will then produce the appropriate load effects. On page 19 Ebasco concludes that "for the purpose of this rate design, we have maintained the same rating periods used in the cost analysis."

Inasmuch as time differentiated costs can, by chosen allocations, be made to produce within limits whatever "costs" will equal the rates necessary to induce the desired load factor, it is possible that time differentiated cost-of-service studies can be used effectively to provide a result, load improvement, that was no part of the ratemaker's original intention. However, if an improved load factor is the ultimate aim, it would seem that this objective should be pursued directly and not, as it is, by indirection, by means of an intellectually faulty scheme of allocation that makes costs coincide with rate structures whose shapes are really determined by other objectives.

Price signals, Ebasco points out, cannot be equally effective for all users. On page 27 it states that small-residence usage that can be transferred to lower price periods is not enough to offset increased metering costs. It does, however, favor curtailment of load at the time of the system peak for large customers. We must also agree with their conclusion (page 29) that implementation of time-of-day rates requires more knowledge than now exists.

It should be emphasized that the above deficiencies in theory are not due to any failure on the part of Ebasco to recognize the nature and complexity of the problems of rate design and the difficulties of finding a universally agreed upon method of allocating joint costs. Ebasco was given the assignment of providing in as great detail as possible the step-by-step allocation process encompassing functionalization, classification, determination of rating periods, and allocation. By reorienting Ebasco's analysis, it is possible to use the data, experience, and knowledge accumulated under the rubric of differential costs in order to move directly to the problem of the load factor and the place of time differentiated rates to improve load and to reduce long-run average costs. In such an analysis, it would be necessary to consider the long-run marginal cost of incremental power, not for the purpose of rate design, but for planning purposes, and then to compare the present embedded costs with those existing at the close of the planning period. Total revenues during any period would be neither the embedded revenue requirements of some dead past period nor the requirements expected to exist some years hence, but the requirements for servicing the operation during the immediately ensuing period. These requirements would, of course, need to be adjusted as new plant came on the line.

Sections A to E, which give the data for five different companies, show that companies having a high daily load factor, 75% to 85% (page 24), are not likely to benefit very much from time differentiated rates and that implementation of time-of-day rates requires additional knowledge. The application of such rates to each of the companies shown would likely be different.

For each of the companies studied, Ebasco finds what might be expected, namely that the long-run marginal costs are far above embedded costs. It is an error therefore to insist that either the level of rates or rate design should be based upon LRIC rather than on test-year embedded costs and then, in effect, to modify away the LRIC in such a way that it ceases to be a guide to either the level of rates or their design. In its many criticisms of marginal cost pricing, Ebasco is therefore generally correct. Marginal costs are relevant to planning purposes, not to rate design or total revenue requirements. In this matter, this writer agrees with Ebasco.

Ebasco's Table V on page A-15 shows the residential rates from Form #1 for Virginia Electric and Power Company. The energy charge on peak for the year 1976 is shown by the embedded cost study to be 7.20¢/kWh, whereas the long-run marginal cost study shows it to be 7.00¢/kWh, only a slight difference. For off-peak hours the results are 2.95¢/kWh and 2.50¢/kWh respectively, a slightly greater difference.

Ebasco finds, however, that for residential users there is little incentive to shift the load sufficiently to offset the cost of metering.

This study, therefore, shows that although improvement of the load factor is, in itself, desirable, it has by no means been established that any reasonably conceivable differential in rates between peak and off-peak can have a significant effect on small users. Each utility must therefore plan its rate design according to the needs of its own users and the probable effect on its system.

Regulatory bodies should therefore seek to obtain such evidence as they can regarding the probable effect on the load factor of different rate structures rather than to work through the route of time differentiated costs of service. A hearing directed to that issue would enable utilities and customers to present their responses and predictions about future behavior rather than merely their opposition to changes based upon so-called ethical considerations and conflicting cost data based upon their own arbitrary and sometimes self-serving allocations. The probable effects of rate changes must wait upon experience. For the present they are a matter of experimental prediction based upon judgment. Human judgment is fallible but it is all that we have and has brought us as far as we have come.

SECTION 5

APPLICATION TO VIRGINIA ELECTRIC AND POWER COMPANY

This study seeks to apply to Vepco the principles set forth in Topics 1.3, 4, and 5. It analyzes this company from the viewpoint of (1) embedded costs, (2) short-run marginal costs, and (3) long-run marginal costs.

On page 2 Ebasco states that the objective of this study is to explain and demonstrate the various methods of cost allocations and (page 4) to develop unit revenue requirements. Ebasco continues to emphasize that the study is primarily directed toward peak-load costing and not cost of service in general (page 6). For this purpose, production plant has been expanded into three subfunctions: base, intermediate, and peak. The BIP method, which gives different weights to the fixed costs of plant used for peak, intermediate (or secondary-peak) and off-peak periods, is therefore a predetermining factor in Ebasco's different unit revenue requirements for each rating period.

On page 28 Ebasco says, "It should be mentioned at this point that the task of classifying the production units is required only for the assignment of fixed costs to the rating periods," and on page 33 it says that "what is needed is some logical means to apportion the fixed costs associated with base load type facilities to not only the off-peak period, but to the secondary and peak periods as well. Intermediate type facilities must be apportioned only to the secondary peak and peak periods. Peaking facilities are exclusive to the peak rating period...Base load units are apportioned into thirds and allocated equally to the three rating periods. Intermediate units are allocated half to the secondary peak period and half to the peak period."

This discussion will be confined to demand related costs because this is the crucial issue in time differentiated rates. Differences of opinion exist relative to energy related costs, but these cost differences are relatively small compared to capacity related costs.

The test-year-1974 results of Ebasco's calculations using four different methods are as follows (pages 49-52):

Method I BIP gives total demand related costs of \$6.98

Method II hours gives total demand related costs of \$6.25

Method III kWh gives total demand related costs of \$6.37

Method IV PCP gives total demand related costs of \$7.25

Method I is the BIP method. Methods II and III allocate demand costs in proportion to hours and kWh usage and give quite similar results. Method IV (probability of contribution to peak [PCP]) is a weighted probability of peak occurrence within each rating period. Methods I and IV give quite similar results.

On page 59 it is shown that Methods I and IV produce peak capacity costs 3.36 and 3.91 times off-peak capacity costs and that Methods II and III produce peak capacity costs 1.30 and 1.59 times off-peak capacity costs. The relative size of capacity costs is therefore determined primarily by allocation.

Although Ebasco seeks a "logical" choice between methods of allocation, there is fundamentally no reason why unit fixed costs should be assigned more heavily to the peak period than to the off-peak period, as is done by Methods I and IV. The choice of allocation methods thus depends upon the type of "end result" desired, and it is not intrinsically correct to assign joint costs, as is done by Ebasco, in BIP and PCP rather than by the hours of use or kWh of use method. Neither method produces "in fact" costs. Both depend upon arbitrary allocations, and neither method should be relied upon to determine the differentials between peak and off-peak rates. That differential should be determined by its effect upon the load factor, which in turn will depend upon the value of the service to users at different times of the day and year. If, perchance, existing rate schedules already conform to this standard and to the structure that would prevail for similar joint products in the competitive market, then weightings can be chosen retrospectively that will demonstrate that the allocated costs of service during each rating period already conform to the prices that exist. However, if some innovator were to find some rate schedules or load control devices that would produce a better load factor, it would then be impossible to put them into effect unless it were first proved that the previously demonstrated "costs" were wrong and that a new cost study would show that the newly designed rate schedules now conformed to the differential "costs" of service.

According to some theories of marginal cost pricing, all of the demand or capacity costs should be allocated to the peak period. Although this author does not agree with that view and considers it basically erroneous in theory and in fact, it would have been helpful if Ebasco had shown the results that would have been produced by application of that version of marginal cost pricing. Theoretically it would, of course, have produced a wider disparity between peak and off-peak costs, and the rates based upon it would tend to produce a greater load shift than that obtained by any of the above four methods.

In an early draft of its Vepco Topic 5 report, Ebasco calls the short-run marginal cost principle "absurd from a pragmatic point of view."* It is, of course, obvious that fixed costs do not remain

*The section on short-run marginal costs was omitted from the final version at the direction of the Project Committee of the Rate Design Study.

fixed even from day to day, but this fact does not void the relevance of the economics of the short-run from a methodological point of view. Short-run marginal costs, construed precisely, are simply the energy costs of an additional kWh or kWhs, which are the fuel costs. The short run as used by the economist is really not a time related concept. It is a heuristic device to separate those costs that vary with the size of plant from those that vary with the size of output. However, ratemaking needs to concern itself both with the revenue requirements and rate schedules that are applicable to the next year or two and with those that will serve best in the long run. Rate design is concerned primarily with the latter; revenue requirements are concerned primarily with the former. Both short-run and long-run concepts are therefore useful, and the short-run concept might be given a time dimension by calling the short run the immediate future period of the long run, which will contain changes both in variable costs and in plant capacity costs.

Ebasco reported* that because of increased nuclear generation, Vepco energy costs may decrease in the short run whereas demand costs are increasing. However, the relation of peak to off-peak demand costs will under its method continue to be approximately 2 to 1, whereas the energy cost relationships will be close to unity.

Long-run marginal costs are construed to mean the costs that will exist at the end of the planning period, which was assumed for Vepco to be 1985. Ebasco used fixed charge rates of approximately 20% in its LRMC cost study (page 70). On the basis of existing rates of return and taxes, this approximation appears to be good. These are, however, variables, and they may actually change during the planning period. Of course, long-run fuel costs are highly speculative, as are also the degree of inflation and its effect on plant costs per kWh.

A wide disparity between peak and off-peak unit demand costs continues to exist (pages 84-85) in Ebasco's calculations.

*In Ebasco's early draft; this section was omitted in the final report.

The major difference between long-run marginal costs (LRMC) or incremental costs (LRIC) and long-run average costs (LRAC) is created mainly by the simple fact that new plant costs more because of inflation. Present costs of capital are also higher than embedded capital costs. However, if rates and revenues based on LRIC or LRMC are corrected to eliminate the so-called windfall profits, then of course the end result on total revenue requirements will be little different regardless of the method used. In either case, the time differentiated costs will continue to depend upon the method of allocating the capacity or demand costs to peak, intermediate, and off-peak periods, and because that allocation depends upon the end result desired, the determination of time differentiated rates is made by reasoning in a circle.

Analysts proceed upon the assumption that a given time related rate structure is desirable, fair, just, and reasonable and then allocate fixed costs in such a way that differential costs tend to coincide with these differential rates. Instead of "costs" determining rates, rates determine costs, and these are then used to justify the rate design.

It is possible to get out of this circle by designing rates not by their alleged time differentiated "costs" but in order to produce the desired load factor within the constraint of the factors of minimums equal to variable costs, and by simulating the structure of prices that would prevail in the competitive market as a result of the value of service at different times of the day and year. This approach to rate design would most likely produce results similar to those obtained by the BIP and PCP cost methods, but the designer would not be bound by costs and would escape the need of reasoning in a circle.

The sometimes expressed view that correct economic theory requires the assumption that all fixed costs of plant be allocated to the peak is demonstrably false. Some economists may believe that to be true or may postulate it to suit their own convenience, but that does not make it true, nor does it make the postulation consonant with the pricing process found in the real world of competitive pricing.

It is, of course, true that the nature of electric service makes it necessary and desirable, even if it were not required by law, to plan capacity to meet the peak load and allow a necessary reserve. But that does not prove that the price of the peak service must include 100% of the capacity costs. This rule does not obtain in the competitive market.

We have shown above that in the unregulated competitive market seasonal price does not vary with seasonally allocated costs. We must now show further that even though utility plant, or any other plant for that matter, may be built to satisfy the peak demand, it does not follow that the builder expects or can reasonably expect to obtain from the peak demand alone all of the revenues to pay for the annual capital costs of that plant. He may build to meet the peak but expects to get revenues to cover his capital costs from both peak and off-peak users. We may illustrate this by analysis of the seasonal hotel industry.

A builder of a hotel that will have occupancy rates varying with the seasons does not need to contemplate or expect to derive all his fixed costs from the peak occupants, and none from the off-peak customers. Before air conditioning, hotel owners in Florida tended to build with the expectation of recovering all their costs from revenues during the winter season. However, after air conditioning, hotels came to be built if the revenues minus costs of all seasons combined provided a reasonable rate of return on invested capital. The rates charged for hotel rooms during each season are determined not by the allocated costs during such a season but by the value of the service and the resulting price that will provide the optimum occupancy so as to provide the greatest net revenues. In Florida, winter hotel rates may be 50% higher than summer rates. In Lake Tahoe summer hotel rates may be 50% higher than winter rates. Such costs as the required return on investment, income and property taxes, and depreciation do not vary with the seasons, and it would be absurd to allocate them so as to make them vary with gross or net revenues during each month of the year. Yet such a method of "costing" is expected by some to be pursued by regulated utilities and is supposed to produce a fair and ethical result.

Hotel rooms in a seasonal area are priced by value of service or according to what the traffic will bear, and prices are kept fair and reasonable by competition among hotel operators. Likewise, peak and off-peak prices of electricity should be priced by value of service within the constraint of the fair return that would obtain in the competitive free market.

The pricing of hotel rooms, peak and off-peak, is more analogous to the pricing of electricity seasonally than, perhaps, the pricing of other joint products such as beef cattle, hogs, or oil and gas. No producer of a joint product expects to obtain all of his revenues or even net return from any one of these products, even if it provided the major source of his revenues, but from all the products combined.

It is accordingly wrong in economic theory to say that hotels are built solely to satisfy the peak demand or that the seasonal prices of hotel rooms cover their fixed costs. Hotels are built to satisfy the total demand, on and off peak, but the prices obtained seasonally are determined by the value of service. If therefore the pricing of electricity is to bear any resemblance to the competitive pricing process, it will not be priced in such a way that total fixed costs are borne by the peak user and the off-peak user will get a free ride.

It is therefore erroneous to confuse the marginal cost theory of pricing for singular products under perfect competition with the marginal cost theory of pricing for joint products. It follows that it is also wrong economics to insist that because the price of a singular product under perfect competition tends to equal marginal cost, then the price of any one of the joint products tends to equal the allocated marginal cost of that joint product.

After ridding ourselves of these ill-conceived obsessions, we may proceed to price electricity on and off peak in such a manner as will achieve the desired load objectives within the appropriate constraints and to throw off the burden of designing rates that conform to time differentiated allocated costs of service.

Rate design that achieves load objectives and simulates the behavior of prices in the competitive market is consonant with the past practice of utilities and their regulators in the aim of achieving the most and best service at the lowest reasonable cost.*

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*Further analysis of this subject is made in Appendix A and in "Pricing of Electricity by LRIC Versus Pricing by Objectives" by Walter A. Morton, pp. 55-76 in "Proceedings of the 1976 Symposium on Rate Design Problems of Regulated Industries," Department of Economics, University of Missouri, Columbia, Missouri. Also "Long Run Increment Costs and the Pricing of Electricity" by Walter A. Morton in Public Utilities Fortnightly, Vol. 97, Nos. 6 and 7, March 11 and 25, 1976.

APPENDIX A

UTILITY EARNINGS AND TIME DIFFERENTIATED RATES

I

The recent emphasis upon rate design in electric utilities had its origin in the shift of the industry from decreasing costs to increasing costs during the late 1960s. This shift required continuous increases in revenues and consequently in rates.

The need for rate increases was, however, due to inflation, which was reflected in the increasing costs of fuel, materials, and labor and in the rising prices for utility plant and equipment, which prices increased at a faster rate than prices in general. At the same time the cost of capital in the form of embedded costs of debt, of preferred and common stock, has also risen. It is these higher combined costs that have made rate increases necessary. The regulatory lag and the tendency toward attrition further decreased utility earnings and consequently the coverage of fixed charges and the earnings on the common stock. Common stock dividends consequently did not increase at the previous rate and caused a lack of faith in the future of the utilities and a fall in market-to-book ratios. In 1974 and 1975 utility stocks generally sold below book.

During this period the idea was promulgated by users of the D.C.F.* cost-of-equity method that a market price equal to book or slightly above book was the right price and that any market price appreciably above book showed that utilities were earning too much. This view was endorsed by some companies and by the staff of the Federal Power Commission. In some jurisdictions this idea appears to have set a ceiling on market price from 10% to 20% above book. This concept I regard as intrinsically erroneous,

*discounted cash flow

injurious to utility credit, and unfair to common stockholders. The latter have not, however, voiced any objection to those utility managements who sponsor this theory, but they do appear to be wary of utility stocks when they begin to sell above book equity per share.

The action of OPEC and the consequent rise in all fuel costs accentuated the tendency of costs to rise and of the rate of return to fall, which caused a further deterioration in utility credit, the downgrading of its bonds, and consequently higher costs of capital, the immediate effect of which was to further increase return requirements and to reduce confidence in the future of utility common stocks.

Resistance to rate increases on the part of the public and some of its purported leaders was often oblivious to its basic causes. Regulatory bodies could do nothing about fuel, labor, and material costs, the cost of new facilities, or the embedded costs of money, so the net effect of a reluctance to provide adequate revenues fell upon the residual corporate claimant, the common stockholder, with the consequent deterioration in his financial position. On the whole, the common stockholder of electric utilities, after pouring additional investment into each share of common stock through retained earnings and new investment, is still receiving about the same dividend measured in purchasing power as he did 10 years ago.

II

Changes in rate design were conceived by some to be a substitute for the higher rates necessary to meet these changing conditions. It was claimed, mostly without foundation, that the residential consumer or small user was being exploited by the declining block structure of utility rates, which encouraged higher usage, and that if the rate design were altered, the need for additional plant capacity and fuel would be reduced, and so also the need for increased revenues.

The basic reasons for higher rates tended to be minimized and the purported effects of rate structures exaggerated. Demand for reform in the rate structure was also used as a vehicle by some interests to shift the increased cost of electricity onto others, to effect a redistribution of income, and to pursue other ethical, social, and ecological objectives through lifeline rates or by inverted rate structures, which would burden the heaviest users: the industrials who could shift the burden to consumers. Since, however, this shifting might hurt industries in those states that thus overburdened them, it was then contended that the new rate design be enforced by federal legislation upon all utilities in all states. Accordingly rate design proposals brought out a conflict of interest and called for extensive revision of federal-state regulatory relations. The effect of inadequate earnings and the agitation about rate design as a substitute for rate increases was a deterioration in utility credit, which caused the abandonment of many construction projects during a period when much idle plant and labor existed in the utility plant construction industries. This arrest has increased costs of plant still further and has been detrimental to income and employment in the economy as a whole.

Recent experience has already demonstrated that the need for higher utility rates cannot be changed substantially by rate design. A rate design that minimizes costs by improving the load factor is, of course, desirable, but its effect on total consumption will be small compared with the effect of elasticity of demand and the general public recognition of the need to save energy and fossil fuels. The public will soon learn that it cannot take out its frustrations with OPEC, cold weather, drought, floods, fuel scarcity, and inflation by destroying utility credit and impairing the ability to fund future plant facilities required to meet the growing need for electricity which must eventually replace some other sources of heat and energy.

Even though rate design cannot overcome the basic causes of rate increases, it should nevertheless be used, to the extent that it is feasible, economic, and convenient, to improve the load factor and to reduce average costs per kWh below what they otherwise might be. Improvement in the load factor might therefore slow down by a small margin the rate of increase in rates and their absolute levels. One utility estimates that load management may reduce the growth of the peak and the amount of generating capability required to serve that peak by about 10%, so that by 1990 generating capability would be about 90% of what it would otherwise have been without rate design and load management. This projection indicates that although improvement in the load factor will have some effect upon costs, it is small. The higher costs of plant per kW, together with higher fuel costs, will continue to require continually higher rates regardless of rate design or load management. The great hopes placed in the ability of load management to bring about a substantially lower rate of increase in utility rates will prove to be illusory. Rate design will, however, continue to be stressed by those who believe they are morally justified in having others pay these increased costs rather than paying the costs themselves. The high ideal of moral right that animates many of these good citizens is to get something for nothing at the expense of their fellow man.

In the past, the aim of rate design has been to fix rates aimed to recover the costs of serving various classes of customers: residential, commercial, and industrial. The present legitimate interest is in the variations of these costs diurnally and seasonally and in the establishment of rates that will encourage a higher load factor. The instrinsic and identifiable difference in the costs of serving various classes of users should not be confused with the purported difference in costs of serving each class by time of day or season of the year. It is therefore necessary to examine the causes of such differential time related costs, the degree to which these differences rest upon demonstrable facts, and the extent to which they rest upon assumptions about the allocation of the joint fixed costs of plant capacity.

III

Although the interest in rate design by utilities, customers, and regulatory bodies for the purpose of reducing the rise in average costs per kWh is legitimate, it has also become the concern of various academic, ratepaying, and political groups that pursue other personal and social objectives. They seek to modify rate structures in order to satisfy their theories of the "right price" or to promote their own interests. There is, consequently, both an economic and an ideological conflict in proposals regarding rate design.

The academic interest in rate design had its origin in the proposal of Professor Harold Hotelling in 1938 that rates should be set at short-run marginal costs, which were then below average costs, and that the resulting deficiencies in revenues should be made up by the government through taxation. Rates from 1938 to about 1969, based on average costs, continued to fall, and usage increased. Rates based on marginal cost would have fallen even further and presumably would have increased usage even more. The marginal cost theorists today hold the same view, except that they substitute the concept of long-run marginal or incremental costs (LRMC or LRIC) for short-run marginal costs. However, because these costs are now far above average costs, their proposal would now provide a surplus of revenues. The theorists are then faced with a dilemma. They must either favor windfall profits or reduce utility rates below their marginal costs by imposing the constraint of revenue requirements based on average costs. They solve their problem by proposing rates based on marginal cost in theory but not following it in practice. They accordingly violate the very economic principles by which they profess to be guided. The most obvious profession of these principles without their practice is found in the rulings of the Wisconsin Public Service Commission, which finds that average costs are a "proxy" for much higher marginal costs--an obvious semantic obfuscation, necessitated by the profession of a theory that cannot be followed in practice.

The principle that rates should be set at marginal cost is based upon an economic theory that purports to show that such rates produce allocative efficiency. This theory is not, in truth, applicable to joint or quasi-joint products or services, where prices are governed not by the marginal cost of each product but by consumer preference for each of the joint products and by their price elasticity. However, the marginal cost pricing theory is being financed by the Ford Foundation and is now entertained by many individuals high in our political life. But they do not emphasize that its application during the period prior to 1970, when marginal costs were below average costs, would have required, in effect, government ownership, whereas its unmodified adoption today would produce the large windfall to utility stockholders that gave the Wisconsin Commission pause. On the other hand, advocacy of the principle and then its modification by the "inverse elasticity" rule produces a violation of the rationale upon which it is based. This compromise of the marginal cost-price principle thus leads to an indulgence in purely semantic confusions such as using average costs as a "proxy" for marginal costs and calling the resulting average cost rates "second bests." This procedure has the appearance, though it lacks the substance, of economic science and conceals the fact that utility rates are actually being determined not by marginal costs but by average costs.

Correct application of the marginal cost principle, insofar as marginal costs can be measured, accordingly produces either a deficiency or a surplus of revenues whenever marginal costs differ from average costs, and if rates are adjusted to overcome these effects, the Pareto Optimum principle, used to justify this theory of allocative efficiency, is violated. We now have the theory without the practice--"the grin without the cat." It is not necessary for rate design to be based upon such intellectually deficient methodologies.

Various theories of rate design are sometimes used by various ratepaying groups. It is, of course, both proper and desirable for each group to show how any rate structure will affect its costs and operations and whether that rate structure is fair and reasonable. The interests of various ratepayers even within a given classification are not, however, necessarily the same. All do not have the same demand factor or the same load factor. Industrials with a high load factor do not necessarily have the same interest in off-peak pricing as those who can shift their operations so as to utilize putatively low off-peak rates. A rate design that will benefit industrial users who operate a night shift may, of course, be offset by a wage shift differential whose cost offsets, partially or totally, any saving in electricity costs. Hence low off-peak rates may not, in practice, actually produce the desired reduction of the peak. These matters are to be considered in rate design but need not offset the general principle that rate design should be used, within effective limits, to improve the load factor and to reduce the peak.

Commercial users may find it difficult to change their load because their usage depends upon public habits and convenience, which they cannot readily alter. For them a change in the use of electricity is affected by relative costs versus benefits or losses.

For the residential user, the time of usage will be determined by the willingness to change customs and activities and the willingness to bear the cold or the heat of the day for a monetary advantage.

A shift in the rate structure favoring one class or another, unless justified by costs, does not affect load or total costs and therefore merely burdens one group and benefits another. Only a rate structure that improves the load factor and reduces the need for additional plant and equipment will benefit all users. Time differentiated rates should be put into effect only after considering probable changes in usage, relative costs, elasticity of demand, and revenue effects.

IV

Time-of-day or seasonal rates* should not be adopted simply because they supposedly conform to peak and off-peak allocated costs. These costs are not explicit, demonstrable facts; they depend upon assumptions and allocations of joint and common costs, which are at best matters of judgment and at worst theoretically arbitrary assumptions.

* Temperature sensitive rates serve the same purpose. See Appendix B.

Because the variables cannot all be predicted with precision, rate design becomes a matter of art rather than of objective science. However, it can be tested by continued observation of its effects and revised with experience.

It is, however, desirable to state the general principles by which rate design is guided. One of the most common principles is that price should equal cost. This would be a valid ultimate principle also for time differentiated rates if costs themselves were mensurable for output produced jointly. Some costs for residential service do not exist for many industrial services. Some specific customer and distribution costs are assignable. But the costs of plant capacity and the willingness to serve both on and off peak must be allocated to peak, intermediate, or off-peak periods, and the method of allocation largely determines differential costs at each time.

If no distinction is made between seasonal and time-of-day consumption, then average costs can govern rates. However, if it is desired to improve the load factor, and rates are to be governed by costs, then an effort must be made to find the cost of power at different times of the year and of the day. Although some specific costs such as customer costs and energy costs can be specifically attributed to specific outputs, the general capacity or demand costs off and on peak cannot. They depend upon allocation. Allocation of demand or capacity costs is therefore necessary under any procedure that purports to find the full peak and off-peak cost of any class of service, no matter whether the costing method be estimated future marginal costs or embedded historical costs.

The following model with assumed inputs demonstrates the relation between average and incremental or marginal capacity or demand costs and peak and off-peak usage.

Let us assume that a utility can sell 1000 kWh from 6 a.m. to 6 p.m., and the same amount from 6 p.m. to 6 a.m. for a total of 2000 kWh. Assume a capital cost of $100 for the required plant. Assume next that the fixed charges--return, depreciation, and taxes--are 20% of the capital cost of $100, or a total of $20. If this $20 cost is attributed to the 2000 kWh sales, the cost will be 1¢ per kWh, as shown in Table 1.

Now suppose, as shown in Table 2, that the 6 a.m. to 6 p.m. users need an additional 1000 kWh, increasing their demand to 2000 kWh, whereas the 6 p.m. to 6 a.m. consumers keep their demand at 1000 kWh. Suppose that this increase requires a doubling of plant capacity (at constant costs per kW). This measure will cost $100 and increase the total cost of capacity to $200; the fixed charge will be 20% of $200, or $40. All this additional capacity was incurred solely to serve the peak users of the additional kWhs. Therefore, the marginal capacity cost of this incremental 1000 kWh is 2¢ per kWh. The average cost of the total 3000 kWh would be $40/3000, or 1.33¢.

Table 1

CALCULATION OF AVERAGE CAPACITY COSTS

I	II		III
Capital Cost of Capacity	DEMAND (in kWh)		Average Annual Capacity Cost per kWh
	6 a.m. - 6 p.m.	1,000	
	6 p.m. - 6 a.m.	1,000	
$100	total	2,000	$20/2,000 = 1¢

Note: Column III is 20% of Column I divided by Column II.

Table 2

CALCULATION OF CAPACITY COSTS WITH
DOUBLED CAPACITY TO SERVE PEAK USERS

	I	II	III	IV
	Capital Cost of Capacity	Demand (in kWh)	Average Annual Capacity Cost (per kWH)	Marginal Capacity Cost--Incremental Capital Cost (per kWh)
Before expansion	\$100	2000	\$20/2000 =1¢	--
Increment	\$100	1000	\$20/1000 =2¢	2¢ all
New total	\$200	3000	\$40/3000 =1.33¢	2¢ if paid by peak users only

Note: Columns III and IV are 20% of Column I divided by Column II.

If, however, the incremental users can be identified and all the marginal capacity or demand costs paid for by them alone, the cost would be \$20/1000, or 2¢ per kWh. If all the demand costs were attributed now to all peak users as a group, the cost and charge to them would be the same: \$40/2000, or 2¢ per kWh. For the off-peak users there would be no capacity or demand cost charge for their demand costs. The following cost-price results of this shift in total demand capacity or demand are shown in Table 2.

1. Average cost before expansion: 1¢ per kWh.
2. Average capacity cost after expansion: 1:33¢ per kWh.
3. Marginal capacity cost of expansion: 2¢ per kWh capacity.
4. Cost if attributed to the peak user only after expansion: 2¢ per kWh.
5. Capacity cost assigned to the off-peak user after expansion: zero, because all paid by peak users.

The marginal theory that assigns all marginal capacity costs to the peak accordingly requires that as soon as there is peak and off-peak usage, the off-peak users get a free ride. If, however, some part of the capacity costs are assigned to the off-peak, the free ride ceases and the off-peak user pays the amount determined by the arbitrary or judgmental allocation that is made.

The examples presented so far have assumed that new capacity could be installed at the old rate. If, as now appears to be true, new capacity costs are about twice per kWh the old capacity costs, then the average and marginal costs will increase as shown in Table 3.

Under the condition that new plant costs twice as much as

Table 3

CALCULATION OF CAPACITY COSTS
WITH HIGHER COST OF NEW CAPACITY

	I Capital Cost of Capacity	II Demand (in kWh)	III Average Annual Capacity Cost (per kWh)	IV Incremental Capacity Costs (per kWh)
Before expansion	$100	2000	$20/2000 =1¢	--
Increment	$200	1000	$40/1000 =4¢	4¢
New total	$300	3000	$60/3000 =2¢	$60/2000=3¢ on peak 0/1000=0¢ off peak

Note: Columns III and IV are at 20% of Column I divided by Column II.

old, it is clear that marginal capacity cost is 4¢, or twice the average capacity cost of 2¢. Regulatory bodies are therefore reluctant to apply the marginal cost theory without modification. If, then, they wish to apply it so as to remove the windfall, they must use a rate structure that produces revenues sufficient to cover capacity costs of 2¢ instead of the marginal 4¢. Moreover, it is clear that the same effect is obtained when the peak rates are increased to the benefit of the off-peak user, whether this measure is justified by allocating more capacity costs to the peak or simply by raising peak rates for the purpose of creating a shift in demand. If the effect on the load factor is the primary reason for time differentiated rates, allocation of capacity costs becomes superfluous.

If the off-peak free-ride theory is adopted there is no problem of allocating capacity costs--they are all assigned to the peak user. But if it is not adopted, then capacity costs must be allocated in some proportion or another, depending on how free or expensive the ride ought to be and on what effect it will have on the load factor.

Insofar as costs determine the time structure of rates, rate design should aim to produce the lowest long-run average cost per kWh for the total quantity that the consumer is willing to buy. Noneconomic considerations such as fuel saving or ecology could alter this guide.

V

Some proponents of marginal cost pricing insist that they favor this policy not because of its presumed desirable effects on load factor but because a price equal to marginal cost is the "right" price. The consumer, if given the "right" peak and off-peak prices, they insist, will then be able to choose between peak price and shift in his demand. Consumer sovereignty prevails, according to this view, and should govern the expenditure for plant, equipment, fuel, labor, and materials.

This view has the appeal of simplicity: price equal to cost seems entirely rational. However, when the cost at any given time is in significant part (say, about half) a joint cost, that cost in economic analysis is incommensurable. It depends rather upon the allocation of joint or common capacity costs, which is nonrational or arbitrary. The "right" price, which purportedly has such beneficent effects, is thus an arbitrary price.

Strict theorists of marginal cost pricing, although still faced with the necessity of defining the hours of the peak and off-peak periods, yet have a consistent theory to apply to this peak, whether it be 1 hour, 10 hours, or 12 hours. Since the incremental plant is built to satisfy peak demand, they simply assign all capacity or demand costs to the peak period and none to the off-peak period. The costs per kWh during the peak period include 100% of the capacity or demand costs; the costs during the off-peak period include none. The joint capacity or demand costs consist of rate of return, taxes, and depreciation, which total about 50% of total costs. There is no difficulty with allocation. The off-peak users get a free ride: the use of the joint plant and equipment without any cost whatsoever.

This result would, of course, undergo a change as the load became more level and there was no differentiation between the usage at different times of the day or seasons. Then each unit of consumption would have the same demand costs.

However, as long as time of use differed, the strict use of pricing by long-run marginal costs, which attributed all demand costs to the peak period, would dispense completely with the allocation problem. Price would equal specifically attributable costs plus such allocated costs on and off peak.

If, however, we view peak and off-peak users as consumers of a service produced jointly by a given plant, this solution is impossible because there is no way of measuring the cost of any joint product. Ham, bacon, pork chops, pigs' feet, and pig skin are produced by the whole hog, and there is no way of ascertaining their individual costs. Moreover, their prices are not determined by such costs. The producer requires only that total price equals total cost. The price of each of the joint components of the pig is determined by supply and demand, and not by the cost of producing that component. Likewise the fixed cost of a hotel does not vary with the seasons, but the price of a room does. It would be absurd to find that the capacity costs of a hotel in Florida were higher in January than in June because the price per room was different during the peak and off-peak seasons. Accordingly, the theory that price is determined by cost for joint products is utterly meaningless in the competitive market. It is meaningful only in the regulated, monopolistic utility market, if the regulator chooses to allocate demand costs in such a way as to make cost equal to the price he chooses to set. To use such a method would be to say that cost is equal to the value of service, or that cost is what the traffic will bear. This method of cost ascertainment was tried by the Federal Power Commission staff when it sought to find the cost of producing casing-head gas, a joint product with oil, water, argon, krypton, CO_2, nitrogen, and whatever else came out of the well. Some analysts used the Sales Realization method of allocation. They used the revenues from gas compared to total sales realization from gas and oil in order to determine the proportion of total costs to be assigned the production of gas. The lower (or higher) the price of gas, the lower (or higher) was its cost by this fallacy of retrospective inference. I presume that if meat packers came under regulation and were mandated by law to price ham, bacon, lard, pork chops, and pigs' feet at their relative "costs," they could find someone to demonstrate with the appropriate allocations that ham costs five times as much to produce as pigs' feet, about the same as bacon, and so on ad infinitum. Being free from regulation by costs, the meat packers do not need to indulge in these practices.

It is, of course, necessary that total costs be covered by total revenues, for utilities as well as for meat packers, hotel owners, or any other businesses producing joint products or time differentiated services. However, it is not necessary to govern the prices of particular increments of service by allocation of joint costs. It is preferable to use, as a guide to price, the principle that the price of a particular service should be governed by both supply and demand. The supply of a kWh of electricity should not be forthcoming at all at a price below its short-run variable cost. But the price at which it is sold should depend upon the value of service, "what the traffic will bear," elasticity of demand, or whatever it be termed.

Inasmuch as total revenues are limited by total costs including a fair return, the average price of the kWhs sold should be equal to average costs. If the demand for off-peak services can be increased by selling them at a price above variable costs but still below average costs, they should be so priced, and the peak services should be priced so as to make up the deficiency of revenues from off-peak services. Total revenues would thus be equal to total costs, but differential pricing due to differences in the value of service at different times of the year or day could still be maintained and would have desirable effects on the load factor, the amount of plant required, and hence the average cost per kWh.

Utilities and regulatory bodies should therefore pursue the objective of improving load factor without being bound either by the straight jacket of marginal cost pricing, with its inherent fallacy of the allocated free ride for the off-peak user, or by allocated embedded costs. The free ride does not obtain in the unregulated market, and allocated cost does not determine price. Each user pays the price produced by the supply and demand for each commodity or service. The totality of joint products will continue to be produced as long as the total revenues cover total costs.

VI

The guide to prices should be neither the political coercion that consumers can exert upon the regulatory body, nor the putative but still unascertainable cost of each of the joint products, but the specifically attributable cost of each class of service plus such portion of the indivisible and unallocable demand costs as would be contained in the price that would prevail in the competitive unregulated market.

In such a market the price for the peak user would not be equal to specific costs plus 100% of demand or capacity costs, and the price for the off-peak user would not be equal to specifically attributable costs with zero contribution to capacity costs; price would, rather, be something above variable costs according to the elasticity of demand. Under competition the revenues from peak and off-peak users would be determined not arbitrarily but by competition among sellers and by the demand of buyers. In the long run it would cover the total costs of delivering the service to both classes of users at a price that corresponded to the value of the service to each.

Any method of costing of the services of a utility that are produced jointly for different classes of users at different times of the day or year will depend upon some arbitrary assumption regarding the allocation of capacity or demand costs. No amount of analysis or experience can overcome the arbitrary nature of any assignment of joint costs. It can be assumed that invariable demand or capacity costs should be allocated all to the peak and none to the off-peak, or by hours of use, or half and half, or one-third and two-thirds, or in any other proportions, and competent analysts have accepted these varying conclusions. It does not follow, however, that the prices that correspond to such allocated costs will be the prices that the customer is willing to pay or that will optimize the load factor, produce the lowest unit cost, and provide the required revenues. Above all, such cost allocations do not show what prices would prevail in the free competitive market under similar joint cost conditions.

Whilst retaining the principle that total revenues must cover total costs including a fair return, it is better to abandon the theory that specific peak and off-peak prices for various classes of service must correspond to peak and off-peak allocated costs, and instead to follow the model of the competitive market.

The minimum price should cover variable, out-of-pocket or avoidable costs for each peak and off-peak service, and the maximum price cannot exceed the value of the service, the elasticity of demand, or what the traffic will bear. The total revenues from such prices should be kept equal to total costs.

In the competitive market, ideally, the price for each kWh of service could not exceed the value of that service, but the actual level of price for each hour of service would be dependent on the demand for each class of service, just as in the gas and oil business the prices of gas and oil are dependent upon the supply and demand of each, and just as in the meat packing business the prices of various cuts of meat are different but must in the aggregate produce total revenues sufficient to cover total costs. The prices that will improve the load factor, satisfy customer demand, and produce the necessary revenues must be estimated and changed with experience. They are indeterminate because they will depend upon changing elasticities of demand for each hour of service and cross-elasticities of demand determined by substitution of one service for another.

The fairness of diurnal and seasonal rate differentials must be judged not by their relation to their alleged costs but by their consonance with the rates that would putatively obtain in the free competitive market, in which there is no free ride.

Some allocations may, in fact, produce relative costs similar to the prices that would prevail in the competitive market. But this result occurs because the cost-of-service studies are consciously or unconsciously guided by the desire to find a result that is fair, equitable, and workable because it simulates the competitive market. Consequently, the end result assumed for quantity and price determines the allocation of fixed cost components; not, as formally appears, that the allocation of fixed cost components determines the price.

Rather than adopt marginal or long-run incremental costs as a guide to peak and off-peak pricing, it is preferable to cease openly and avowedly to allocate capacity costs on and off peak, and to adopt a theory of diurnal and seasonal pricing that is consistent with the avowed objective: to improve the load factor, to reduce the growth in plant, and to minimize total costs and costs per kWh at the desired level of service.

The suggestion to cease allocation of demand or capacity costs by season or time of day and to price all services so as to take into account specifically attributable costs and value of service within the revenue requirements is by no means revolutionary. That has been the practice of utilities during the long period up to 1970, when incremental and average costs were falling. The level of rates was determined by revenue requirements, but the structure of rates was determined by ascertainable costs and value of service. For example, in such an industry as telephony, which makes wide use of time-of-day rates, it would be difficult to prove that a 10-minute call "after seven" uses less capital facilities than the same call "before seven." Yet that call may be priced lower in order to induce usage and thus to maximize gross and net revenues.

VII

It is an error on the part of commissions and companies to pretend to find the true cost of every service that is in part the product of a common plant. The basic fallacy of finding a true allocated cost of service by arbitrary allocations was illustrated in the opinion of the Supreme Court of the State of New Mexico, filed April 20, 1977, which unanimously reversed the New Mexico Public Service Commission's denial of a rate increase for Mountain Bell Telephone Company on the ground that the company had not produced a satisfactory "cost of service" for each of the many services. In the words of the court, (page 9 of the opinion memo): "The Commission, by its order, found 'an absence of reliable cost information' and said, 'we are convinced that the absence of reliable cost and revenue data exists in the evidence offered to support each and every proposed rate or charge in every service category.'"

The court said that the record revealed that the commission "was determined to develop cost-of-service data for each of the services rendered by Mountain Bell" (page 16) but that it provided no basis for making allocations of the costs of producing a joint product or service. This is, of course, theoretically impossible, and arbitrary allocation is nonrational. The court said that witnesses had testified that for "seventy to eighty years prior to 1969, there was a generally consistent policy throughout the United States whereby regulatory commissions established telephone rates by looking at costs and revenues on a statewide basis," (page 17) but that since then the

Bell System had begun "to itemize the costs of these competitive services for use in avoiding anti-trust actions" and the "regulatory commissions began requiring additional cost studies for other services" (page 17).

The court showed an excellent grasp of economic principles and the fallacy of the "costing" procedures using "arbitrary" methods of allocation (page 18) and on pages 19 and 20 made the following statement regarding these cost procedures. "The end result of the machinations is not a determination of the actual cost of any given service. Use of the term 'cost of service' is an oversimplification. At best, the result represents an educated guess as to what the costs may be in the test year. It cannot be dignified by being considered a factual determination. It is tenuous expert opinion, or informed-judgment evidence, based upon extremely complex and elusive information." The court continued by saying that value of service may be entitled to more weight in ratemaking than "cost of service which necessarily involved many allocations on a more or less arbitrary basis" (page 20).

The court pointed out further that the applicant was being required by the commission "to present 'definitive cost justification' with no enunciation of the means by which the costs are to be justified."

This decision of the New Mexico Supreme Court therefore makes it clear that the law of New Mexico does not require a utility to perform an impossible task and that "arbitrary" allocations produce arbitrary costs and not factual costs. Whether the law of other state jurisdictions or of the United States requires the adoption of the rule of unreason in utility ratemaking still remains to be determined.

VIII

It may be objected that if allocated costs are abandoned as a guide to rates then no guide is left and rate structures will be determined by economic or political pressures and influences. But it is also possible that if allocated costs are used as a determinant of rates the same pressures will be used to determine the allocation, all the way from 100% of capacity costs at peak and a free ride off peak, to any numbers in between.

It may also be said that abandonment of costs as a price determinant, even if they be allocated costs, would replace the usual conception--that fairness requires that prices be equal to costs--with much more volatile, indeterminate ethical considerations. There is much truth in this observation. Ethical conceptions about the fair price differ with each person's values, interests, ideas, and feelings and would be an uncertain guide to ratemaking. Jurists were long wary of equity. As an English jurist has said it, equity is "a very unruly horse, and when once you get astride of it you never know where it will carry you."

For that reason the fair price has been construed to be the price that would prevail among willing buyers and sellers in a competitive market. It is that conception that I propose as a guide to time-of-day and seasonal differentials in rates.

There is no need to conceal the fact that the objective of such rates is to improve the load factor and to minimize costs while providing the optimally desired service at the lowest cost.

It might also be said that individual rates divorced from "costs" may not meet the sanction of the courts. Speaking without legal qualifications, I venture that if the courts find that a given rate structure contains differential peak and off-peak rates that are not justified by allocated costs, but that this rate structure produces the revenue requirements including a fair return on the capital invested, improves the load factor, saves capital costs, lowers rates, economizes on the use of fuel, and approximates the results of the simulated competitive market, they will hold that the rates conform to law despite previous dicta and despite any cost-of-service studies based on allocated capacity costs that purport to show that the time differentiated rates do not correspond to such allegedly time differentiated costs.

Of course time differentiated prices alone need not be relied upon and are not now being relied upon exclusively to improve the load factor. Other controls, which are aided by interruptible rates, are being used for the accommodation of the load to capacity. All such methods of load management can be followed along with whatever aid is provided by and in conjunction with the "price signals" given by differential pricing.

Time differentiated pricing can be guided by its avowed objective: to improve the load factor, to reduce plant capacity per kWh, and to minimize average costs per kWh. Pricing by these objectives should take the place of pricing by allocated fictional costs of service.

Pricing by objectives, however, unlike pricing by marginal costs or LRIC, does not furnish a single simple guide whose contents, however, are in fact considerably arbitrary. But it does set forth the true reasons for rate policy. Pricing can be made free of arbitrary cost allocations no matter how reasonable they may appear to each user. Such pricing policies, moreover, need not deny the use of marginal or of average costing methods where relevant to incremental decisions to expand capacity. They can also take into account self-generation and substitute sources of energy. It will free decision making of illicit theory and of arbitrary assumptions posing as ultimate truths and enable the industry and its regulators to pursue their objectives free of needless theoretical encumbrances.

APPENDIX B

TEMPERATURE SENSITIVE RATES

Peak-load pricing need not be confined to diurnal or seasonal rating periods. Since temperature largely determines the air conditioning load, the peak can be defined as the time at which the temperature exceeds a specified level. It has recently been suggested that during the summer peaking season, temperature sensitive rates be applied (testimony of Gary R. Couillard, of the Wisconsin Public Service Commission, on August 3, 1977, in Docket No. 6630-ER-2, Wisconsin Electric Power Company). Mr. Couillard testified that "a basic diurnal type time-of-day rate does not adequately reflect the cost characteristics of producing electricity for those customers with temperature sensitive loads." He therefore recommended that "customers who consume additional amounts of energy on the peak summer day should pay a higher rate than for usage during the other summer periods." He pointed out further that: "The New York Public Service Commission presently has before it a recommended decision to accept a temperature sensitive rate (proposed by Lilco and recommended by the Examiner) in Docket 26886 Long Island Lighting Company (Lilco). The Lilco rate will apply to 900 residential customers. The temperature sensitive provision is effective whenever the temperature exceeds 83°. The temperature sensitive rate is 26.0¢/kWh as compared to an average summer on-peak rate of 3.3¢/kWh and an off-peak rate of 2.5¢/kWh." According to these calculations the temperature sensitive rate would be 800% of the summer peak rate and 1000% of the off-peak rate, and these rate differentials purportedly represent "cost differentials."

As suggested in New York, temperature sensitive rates can be made extremely high to prevent the needle peak, but this can be

*The New York Public Service Commission has formally approved time-of-day rates for approximately 1100 residential customers that have annual electricity consumption which exceeds 45,000 kWh. The approved rate structure has a temperature sensitive rate of 29.3¢/kWh when the temperature reaches 83°. Consult New York Public Service Commission, Opinion and Order No. 77-11, Case 26887, Long Island Lighting Company, September 1977.

done without resort to justification by purported allocated costs. Such costs calculated under the assumption that all demand costs are allocated to the peak will vary with the length of the rating period chosen. Theoretically, they could be as low as 3.5¢ or as high as 26¢ per kWh, depending on the length of the rating period. The temperature sensitive "cost" per kWh would, of course, be higher if the effective temperature were made 93° instead of 83°, and lower if it were made 73°. The theory that rates should be equal to marginal costs is therefore devoid of content until the rating periods and quantities are specified.

It is preferable to design rates that tend to eliminate needle peaks and to improve the load factor so as to achieve optimum use of plant to satisfy customer demand than to make a calculated allocated "cost of service" at each of various selected margins and then design rates to conform to such arbitrarily allocated "costs." The electric power industry, like others, should seek to price its output so as to affect demand in such a way that it will not be encumbered with plant that is used for only short periods of time. Other industries, ordinarily, do not build plant to meet all possible peak demands for their products or services.