INPUT PRICES AND PEAK USE:
SOME IMPLICATIONS OF MARGINAL COST PRICING

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Regulatory commissions throughout the United States are coming to grips with how the principles of marginal cost pricing can be applied to utility service rates. The concept of marginal cost pricing as the most efficient resource allocation mechanism is certainly not new. Moreover, it is difficult to dispute the theoretical merits of marginal cost pricing. Substantial debate does arise, however, in regard to "real world" practical applications of the principle.

This paper will briefly examine the major areas of controversy surrounding the use of marginal cost pricing as a basis for setting utility rates. Essentially three major arguments are currently being raised against basing rates on marginal cost:

1. Revenues will not be sufficient to cover costs under marginal cost pricing.
2. Off-peak customers would not be bearing their "fair share" of capacity costs under marginal cost pricing.
3. Marginal cost pricing is simply not feasible in the real world.

As to the first argument, the economic theorist will give a hearty, if not convincing, reply, "That's not necessarily so!" He has in mind, of course, the condition in which both short-run and long-run marginal costs are equal to long-run average cost. Under such conditions, the equating of long-run (and, thus, short-run) marginal cost with price brings about a situation in which total revenues will be just sufficient to cover total costs. In reality, this means that a utility system has been planned such that the amount and configuration of capital facilities minimize the present value of total costs. Perhaps an example would be

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FIGURE 1

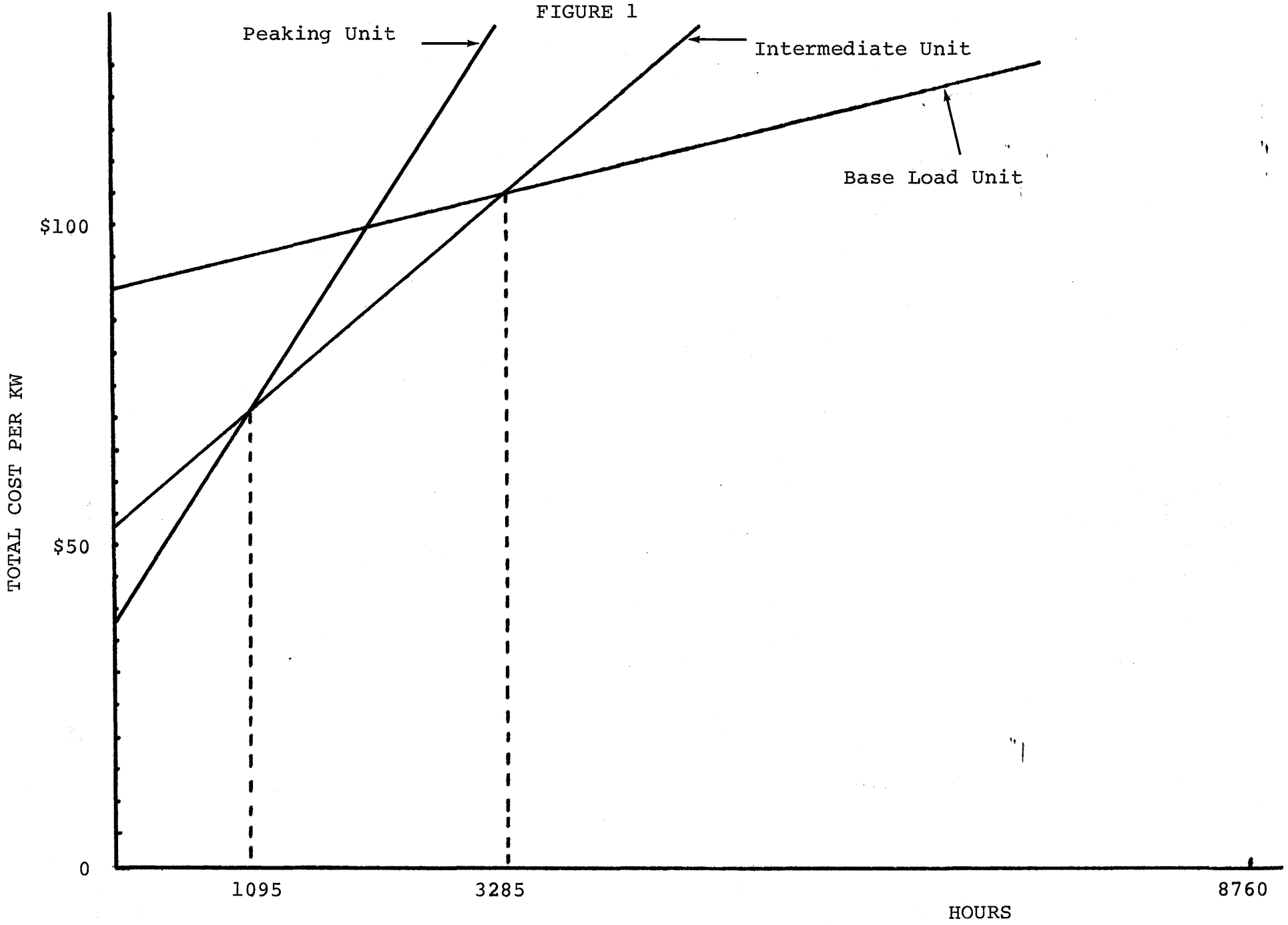
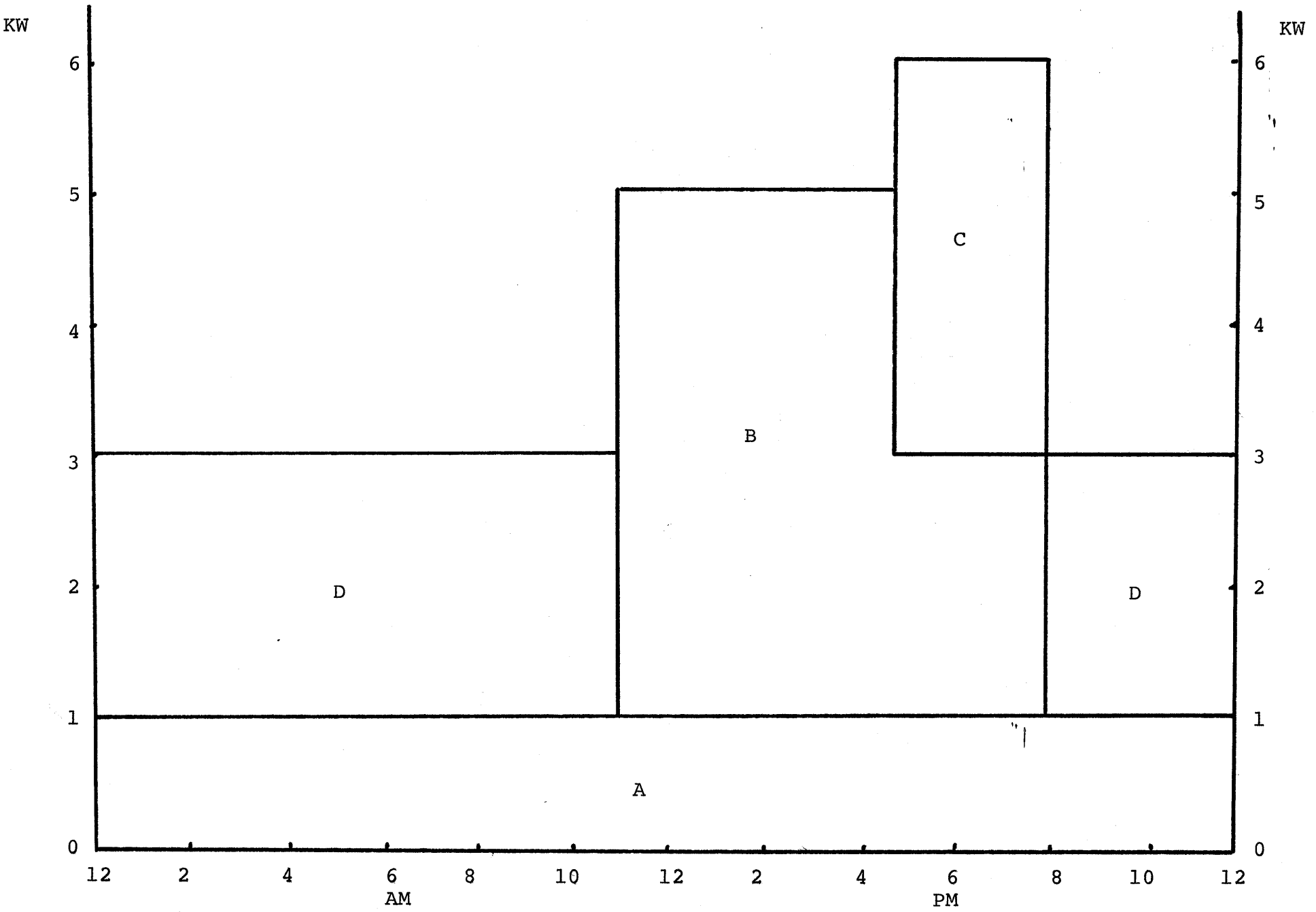

Peaking Unit
Intermediate Unit
Base Load Unit
$100
$50
0
TOTAL COST PER KW
1095
3285
8760
HOURS

FIGURE 2



the easiest means of illustrating this point.[1]

We will assume that an electric utility has an array of plants of varying initial and running costs from which to choose its optimal system. Given the system load curve, the utility will choose the cost minimizing combination of plants. Table 1 gives cost data for the three types of plant in terms of initial cost per kilowatt, the annual charge, and the running cost per kilowatt-hour.

TABLE 1

	Type of Plant		
	Peaking	Intermediate	Base Load
Capital Cost ($/KW)	$187	$359	$600
Annual Charge (%)	20%	15%	.15%
Energy Cost ($/KWH)	$.03	$.015	$.004

Figure 1 indicates the relationship between total cost per kilowatt and hours of operation for each of the three types of plant. Each cost curve intersects the vertical axis at the annual capacity charge and rises as the hours of operation increase. Up to 1095 hours, the peaking type capacity has the lowest total cost. The intermediate type capacity has a lower cost up to 3285 hours of operation. Beyond that, base load capacity has the lowest total cost and, if demand warrants it, would be operated for the entire year. Given the optimal running hours for the three types of capacity, the system load curve will indicate the amount of capacity of each type needed such that the total costs of the system are minimized.

Figure 2 presents a hypothetical daily load chart of the utility. There are four customers, A,B,C, and D, each having quite disparate consumption patterns. Customer A demands one kilowatt throughtout the entire course of the day. Customer B demands four kilowatts from 11 A.M. until 5 P.M. and two kilowatts from 5 P.M. until 8 P.M.. Three kilowatts are demanded by customer C between 5P.M. and 8 P.M.. Finally, customer D demands two kilowatts from 12 midnight until 11 A.M. and from

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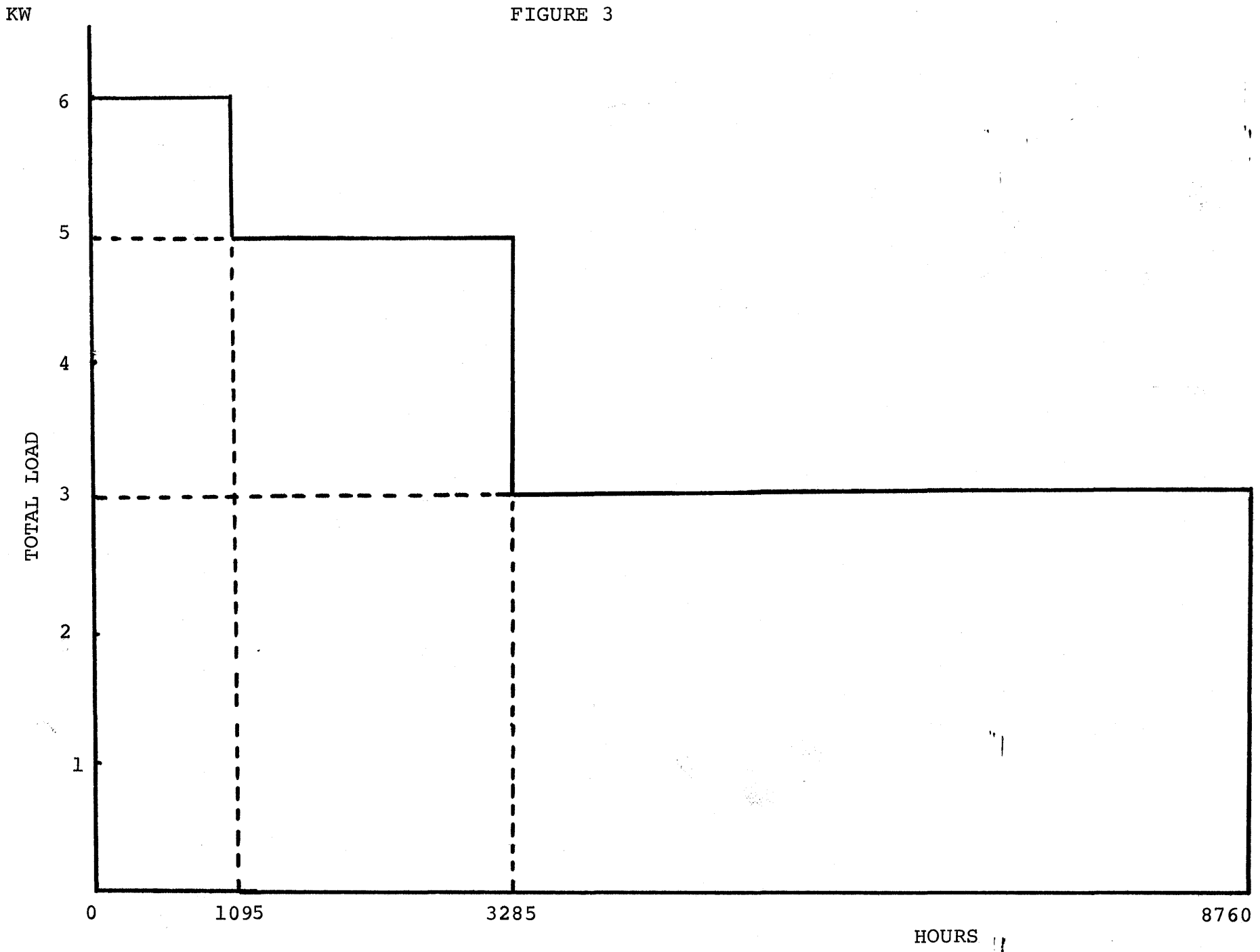
[1]All examples which follow draw heavily on the techniques employed by S.H. Streiter, Senior Consultant, National Economic Research Associates, in a paper entitled "Marginal Costs and Electricity Prices," delivered before the American Public Power Association in Washington, D.C. on January 27, 1975.

FIGURE 3



8 P.M. until 12 midnight. We will assume for sheer simplicity that the daily load chart of Figure 2 is indicative of consumption patterns on every day of the year. Table 2 indicates the total kilowatt-hours consumed annually, individual maximum demand, individual peak period demand, and the individual load factor for each of the four consumers.[2]

TABLE 2

CUSTOMER	KWH CONSUMPTION	MAX. DEMAND (KW)	DEMAND AT PEAK (KW)	CUSTOMER LOAD FACTOR
A	8,760	1	1	100%
B	10,950	4	2	31.25%
C	3,285	3	3	12.5 %
D	10,950	2	0	62.5 %

By aggregating daily load curves we may arrive at the annual total load curve depicted in Figure 3. An examination of Figure 3 indicates that in order to meet the demands of its four customers, our hypothetical utility must provide, on an annual basis, 6 kilowatts of power for 1095 hours, 5 kilowatts for 2190 hours, and 3 kilowatts for 5475 hours. Accordingly, our cost minimizing utility will employ a 1 kilowatt "peaking unit" for 1095 hours, a 2 kilowatt "intermediate unit" for 3285 hours, and a 3 kilowatt "base load unit" for 8760 hours.

The total annual costs of the utility may be calculated as follows:

PEAKING CAPACITY: (\$187) (.20) (1KW)+(1095 hours) (\$.03/KWH) (1KW)=\$70.25
INTERMEDIATE CAPACITY: (\$359) (.15) (2KW)+(3285 hours) (\$.015/KWH) (2KW)=\$206.26
BASE LOAD CAPACITY: (\$600) (.15) (3KW)+(8760 hours) (\$.004/KWH) (3KW)=\$375.12
TOTAL COST = \$651.63

Under marginal cost pricing, each consumer will be billed at the annual charge of the peaking unit for each kilowatt, or portion thereof, that they demand during peak periods. Furthermore, each customer will be billed the running cost of the

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[2]The customer load factor is defined as the average load of the customer expressed as a percentage of his maximum load. For example, customer B's load factor would be calculated in the following manner:

Load factor=Average load/Peak load

$$=\frac{10,950\text{KWH}}{8,760\text{hrs}}/4\text{KW}=1.25\text{KW}/4\text{KW}$$

=.3125 or 31.25%

"marginal unit" in each period. The calculation of annual customer bills would be made as follows:

Customer A: ($187)(.20)(1KW)+(1095 hours)($.03/KWH)(1KW)
+(2190 hours)($.015/KWH)(1KW)+(5475 hours)
($.004/KWH)(1KW) =$125.00
Customer B: ($187)(.20)(2KW)+(1095 hours)($.03/KWH)(2KW)
+(2190 hours)($.015/KWH)(4KW) = $271.90
Customer C: (187)(.20)(3KW)+(1095 hours)($.03/KWH)(3KW) =$210.75
Customer D: (5475 hours)($.004/KWH)(2KW) =$43.80
TOTAL OF CUSTOMER BILLS: $651.45

In this example, under marginal cost pricing total revenues will cover total costs.[3]

We have assumed throughout this example that the utility is capable of "proper planning." That is, the utility has installed a combination of generating units such that the present value of total costs is minimized. Under "normal" conditions, a "real world" utility would attempt to plan its system such that the discrepancy between total revenue and total cost is quite small. As mentioned earlier, this implies that long-run and short-run marginal costs are equal. Currently, sharp aberrations in fuel prices have made fossil fueled generating plants non-optimal, and thus, current short-run marginal costs will be greater than long-run marginal costs after reoptimization of the system.

Returning to the initial argument against marginal cost pricing, opponents of this pricing scheme do indeed make a good point in that electric utilities have experienced in recent years numerous drastic changes in input prices. An electric system is optimized on the basis of not only current input prices but also expectations for future input prices. When expectations for the future are not met, a system planned according to those expectations will simply no longer be optimized. If marginal cost pricing is employed to recover the costs of a non-optimized system, revenues will not be equated with costs.

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[3]In this paper, rounding errors can account for minor differences such as the discrepancy of 18¢ between total costs and total revenue.

Pricing under a condition of non-optimality is a problem not easily resolved. Consider a case in which an electric utility faces excess capacity due to either shrinking demand or indivisibilities in capacity components. In the presence of excess capacity, pricing according to marginal costs will result in a level of revenue insufficient to cover total costs. The inequality between revenue and cost is the result of the annual capacity charge on the unused portion of the system. How should such a problem be resolved?

On one hand, it may be argued that the system's excess capacity is neither used nor useful and, as such, should not be earning a return (or accumulating a depreciation reserve if depreciation is a function of time). Under this line of reasoning, the deficit would be borne by the utility's stockholders in the form of a lower capital base and, thus, lower earnings. Realistically, this strict treatment of burden would apply only in a case of blatant mismanagement in the planning process. This possibility is most improbable given the fact that most regulatory commissions must, as the arm of the "public", pass judgment as to the desirability of an initial investment. Given the commission's initial approval of an investment which later proves noneconomic, it would seem reasonable to assume that the utility, to the extent that later conditions could not have been forecast during the system planning period, should not be made to bear the full burden of the deficit between cost and revenue. That is, both the firm and the consumer should be made to bear the deficit.[4]

The easiest means by which consumers may be made to assume their portion of the deficit would be through rate increases over and above the marginal cost based rates. An efficiency problem would arise, however, in that consumers would no longer be facing the proper pricing signals on which to base their consumption

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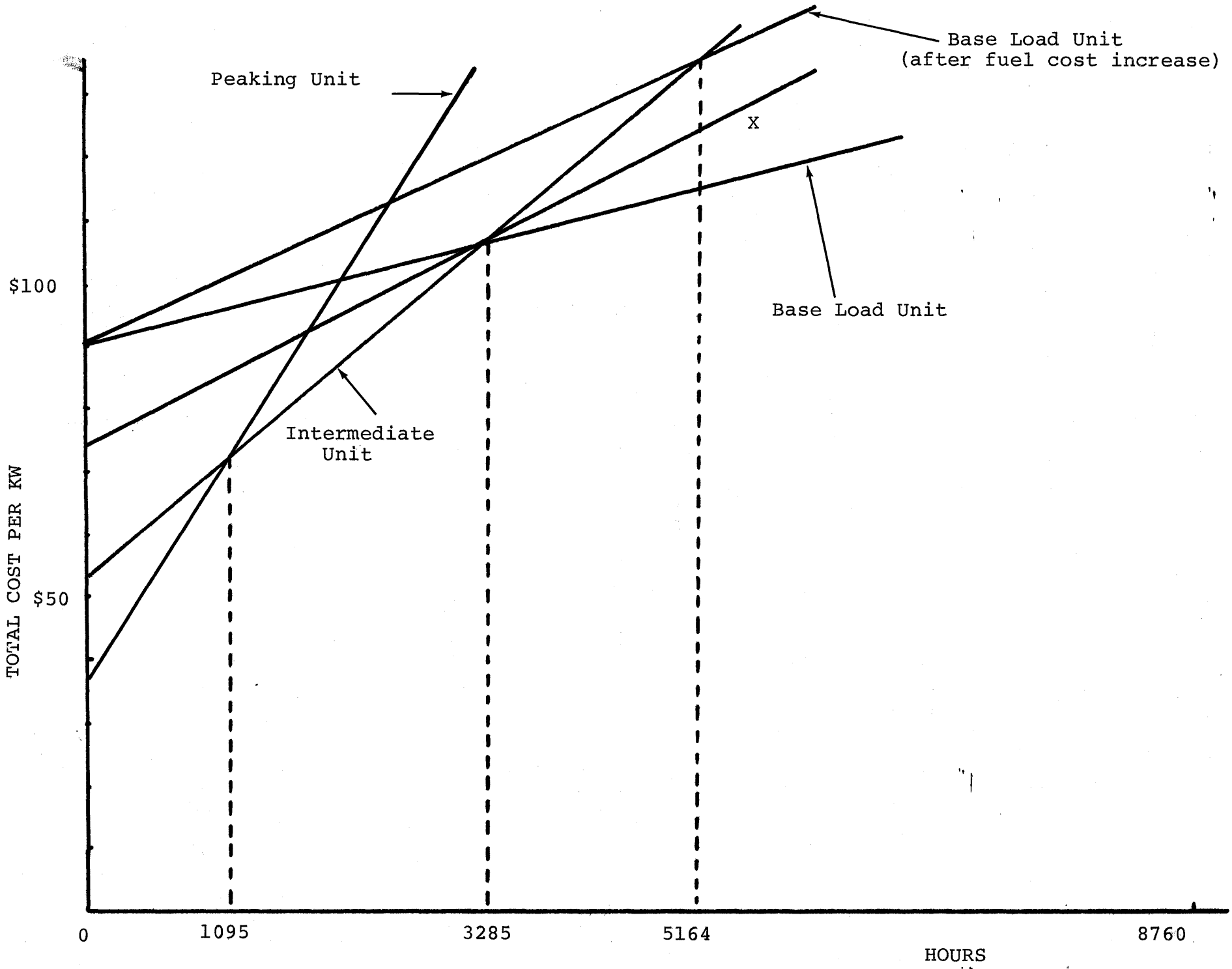
[4]The extent of the relative burdens would be determined on the (admittedly subjective) basis of how much foresight the utility could have had in recognizing a future aberration in trends. If the utility could clearly not have foreseen a major aberration in trends resulting in excess capacity and the initial investment was approved by the commission, the consumers would likely bear the greater burden, if the utility is to continue to remain in the previous risk class.

FIGURE 4


Base Load Unit
(after fuel cost increase)
Peaking Unit
X
$100
Base Load Unit
Intermediate
Unit
TOTAL COST PER KW
$50
0
1095
3285
5164
8760
HOURS

decisions. A more efficient method would involve taxing customers by the appropriate amount of the deficit and retaining the rates based on marginal cost. A related issue concerns the question of responsibility among various consumers for excess capacity. Are peak load users more casually responsible for excess capacity than those who are strictly off-peak users? A discussion of this and related questions would go beyond the scope of this paper. The whole problem of the treatment of excess capacity under marginal cost pricing will, of course, be mitigated by the increased institution of power pooling and coordination efforts among utility systems.

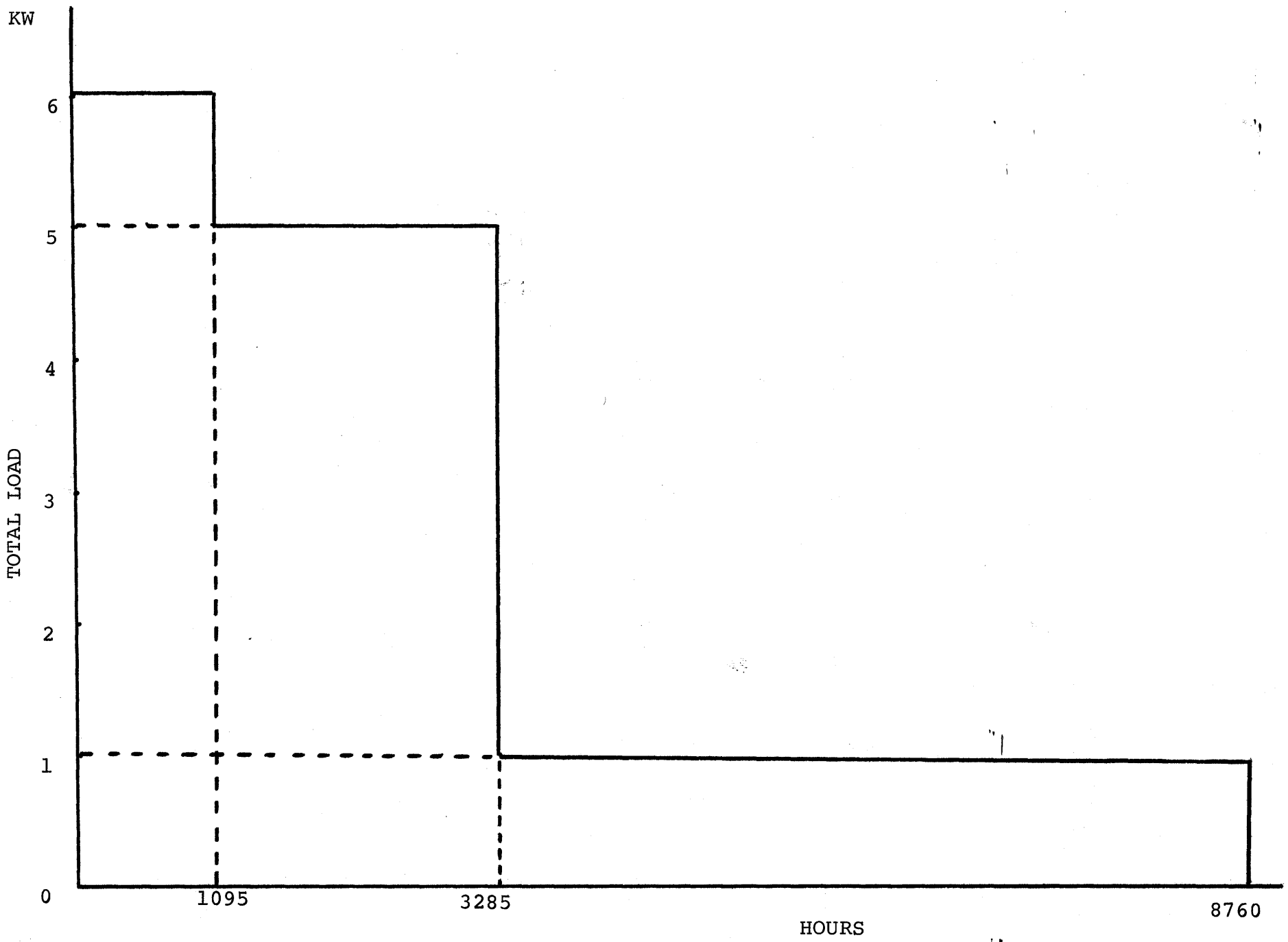
A related problem concerns unanticipated fuel cost increases. As noted earlier, the sharp increases in fuel costs experienced in recent years have made previously optimized systems now nonoptimal (short-run marginal costs exceed long-run marginal costs). It is debatable whether the utilities' stockholders should be held responsible for meeting the burden of insufficient revenue resulting from unanticipated increases in fuel prices. Appropriately, fuel adjustment provisions allow fuel cost increases to be passed on to the utilities' customers. Presently, the adjustment for fuel cost increases, in most jurisdictions, occurs on a per kilowatt-hour basis without regard to the timing of customers' consumption patterns. Such a cost recovery scheme is, of course, far from efficient. For example, a strictly off-peak customer may require nuclear-fueled base load capacity. To force that customer to face a fuel adjustment based on increases in the price of oil is to deny him the correct price signals. Under marginal cost pricing, wherein the timing of consumption is taken into account, fuel adjustments could be made to properly reflect causal fuel cost responsibility.

When fuel costs of one type of generating plant, say base load capacity, increase, marginal cost pricing results in a deficit. The deficit is incurred because only the off-peak customers face the base load running costs of a system even though these costs are incurred throughout the year. Observe in Figure 4

the effect of a 100% increase in base load running costs. Recall that the intermediate plant was formerly the least cost unit between 1095 hours and 3285 hours of operation. After the increase in running costs of the base load unit, the intermediate plant is the least cost unit between 1095 hours and 5164 hours of operation. Essentially, the system's plant configuration is not optimal given the system's load characteristics. There exists no combination of the three types of plant presently in the system which will be optimal in regard to serving the system's load, given the increase in base load running costs. A reoptimized system would entail replacement of the base load unit by some other technology such as X in Figure 4. Prior to the increase in running costs of the base load unit, X was not the least cost technology available for base load capacity. Were technology X to be installed to replace the system's base load capacity, the system configuration could again be optimized vis-a-vis the system's load. Until such time as reoptimization is financially feasible, a divergence from strict marginal cost pricing is necessary to ensure revenue sufficiency. Alternatively (and more realistically) it is highly unlikely that there will be a sufficient array of plants such that the system may be reoptimized. In such a case, the system will be restructured so that the present value of total costs is minimized and both the configuration and size of plants are as close to optimal as possible. A two-part tariff could ensure the equality between revenue and cost and, at the same time, provide the proper marginal signals to customers.

It is important to note that marginal cost pricing under a non-optimal system does not necessarily create a deficit. Consider the case of an increase in running costs of the system's peaking unit. It may be demonstrated that under strict marginal cost pricing revenue will be greater than cost. Again, if the system may be reoptimized by replacement with another technology, there is no problem. If reoptimization is not realistically possible, a two-part tariff could reduce revenue to the point of equality with cost.

FIGURE 5



those who consume at the peak, since the capacity level of a system is determined by the amount demanded during that period.

The only basis for an argument to the effect that off-peak customers should pay a portion of capacity costs would have to be grounded in equity considerations. For example, if low income users are predominantly peak load customers, society could conclude that rather than direct income subsidies, such customers should receive subsidized electricity, the costs of which may be reduced by charging off-peak customers some portion of capacity costs, thereby lowering the price to low income users. Income redistribution would be achieved under such a pricing scheme, but economic efficiency would be ignored; customers would no longer be facing the proper pricing signals on which they base their consumption decisions. By pricing below marginal cost to peak users and above marginal cost to off-peak users, consumption at the peak would likely increase, with off-peak consumption decreasing. The ultimate result would be a lower system load factor. Any equity based argument against marginal cost pricing must necessarily take into consideration the misallocation of resources resulting from a non-marginal cost pricing mechanism and the fact that there are more direct ways of raising incomes of the poor.

The third argument against marginal cost pricing regards the feasibility in the "real world" of such a pricing scheme. Certainly one must weigh the benefits to society through a more efficient allocation of resources against the costs of the more expensive metering technology. Although this technology is currently rather high priced, there is no reason to doubt that the price will fall due to economies of scale in production as demand increases. Nonetheless, the price of the new metering devices must be considered in assessing the net benefits of marginal cost pricing.

A long-held principle of utility rate making has been that rates should be designed with relative stability in mind and with a minimum of sharp increases

over time. Under marginal cost pricing, peak users will experience the greatest increases in their bills vis-a-vis their bills under a fully distributed (or, roughly, average) cost basis of pricing. Off-peak customers, on the other hand, will realize lower bills under marginal cost pricing. By way of an example, let us compare annual customer bills under both fully distributed and marginal cost bases of pricing. In our initial example using customers A,B,C and D, total cost of the system was $651.63. If this cost were divided by the total number of kilowatt-hours consumed during the year (33,945 KWH), we would have a rather simplistic approximation to rates based on fully distributed cost, i.e., $.01919 per kilowatt-hour. Let us assume (as we have implicitly done this far) that the four demands are completely insensitive to price. Accordingly, the annual customer bills would be calculated as follows:

		Marginal Cost Bill
CUSTOMER A:	(8760 KWH) ($.01919/KWH) =$168.16	$125.00
CUSTOMER B:	(10,950 KWH) ($.01919/KWH) =$210.21	$271.90
CUSTOMER C:	(3,285 KWH) ($.01919/KWH) =$63.06	$210.75
CUSTOMER D:	(10,950 KWH) ($.01919/KWH) =$210.21	$ 43.80

A comparison of marginal cost based bills with those based on fully distributed cost, indicates that those customers who are peak users (especially C who consumes all of his electricity at the peak) realize a very sharp increase in their bills under marginal cost pricing. Customer D, the only strictly off-peak user, realizes a sharp decrease in his bill as a result of marginal cost pricing.

Throughout this analysis, no consideration has been made regarding price elasticity of demand among the various customers. In light of the drastic changes in customer bills after marginal cost pricing is involved, it would be most unrealistic to assume that individual's consumption patterns would remain unchanged. In fact, by providing the correct economic signals, users have an incentive to make adjustments in their consumption patterns; such adjustments can lead to a more efficient utilization of energy resources.

Let us now consider the second argument against marginal cost pricing of utility services: Off-peak customers would not be bearing their "fair share" of capacity costs under marginal cost pricing. Many opponents of marginal cost pricing contend that off-peak customers would be getting a "free ride" in that they would be using generating capacity but would not be contributing to the recovery of capacity costs. In the previous example, customer D is a strictly off-peak user and, under marginal cost pricing, pays only the running costs of his consumption. Is this a "fair" means of pricing from the standpoint of peak users? To answer this question, let us compare the annual bills of customers A,B, and C in the absence of customer D with the bills previously calculated.

In the absence of customer D, the annual total load curve of the utility would appear as in Figure 5. It is evident that without the necessity of serving D, the optimized utility will employ a 1KW base load unit as opposed to a 3KW unit and a 4KW intermediate unit rather than a 2 KW unit. The total cost of such a system would be calculated as follows:

PEAKING CAPACITY: ($187)(.20)(1KW)+(1095 hours)(.03/KWH)(1KW) =$70.25
INTERMEDIATE CAPACITY: ($359)(.15)(4KW)+(3285 hours)($.015/KWH)(4KW) = $412.52
BASE LOAD CAPACITY: ($600)(.15)(1KW)+(8760 hours)($.004/KWH)(1KW) = $125.04
TOTAL COST: $607.81

Under marginal cost pricing, the total of annual customer bills (and, thus, total revenue) may again be demonstrated to cover total cost:

CUSTOMER A: ($187)(.20)(1KW)+(1095 hours)($.03/KWH)(1KW)+(2190 hours)($.015/KWH)(1KW)+(5475 hours)($.004/KWH)(1KW) =$125.00
CUSTOMER B: ($187)(.20)(2KW)+(1095 hours)($.03/KWH)(2KW)+(2190 hours)($.015/KWH)(4KW) =$271.90
CUSTOMER C: ($187)(.20)(3KW)+(1095 hours)(#.03/KWH)(3KW) =$210.75
TOTAL OF CUSTOMERS BILLS: $607.65

The important point in this example is, of course, that the annual customer bills of individuals A,B, and C are the same regardless of whether customer D does or does not consume. Customers A,B, and C are therefore made <u>no worse off</u> by the presence of the strictly off-peak customer, D. Under marginal cost pricing, customer D pays only the running costs of his consumption since he is not "causally" responsible for capacity. Those who do bear causal responsibility for capacity are

Nevertheless, marginal cost pricing may initially bring about substantially sharp rate changes to groups of customers, which suggests that the adoption of the pricing principle might involve movement toward a "target" rate structure. Sharp shifts may be inequitable and can lead to economic dislocations. A gradual move in the direction of a "target" rate structure based on considerations of long-run incremental cost could minimize this conflict.

The purpose of this paper has been to briefly examine some of the major arguments against marginal cost pricing of utility services. No attempt has been made to fully resolve the conflicts surrounding this pricing scheme. Instead, the paper attempts to clarify some of the issues about which the major arguments revolve.

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