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Socioeconomic Environmental Studies Series

The Economic and Environmental Benefits from Improving Electrical Rate Structures

Office of Research and Development
U.S. Environmental Protection Agency
Washington, D.C. 20460

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EXECUTIVE SUMMARY

This is a study of the pricing practices of the electric power industry, motivated by the importance of this industry to any overall program of environmental management. The generation of electricity is a major source of air and therm pollution; the siting of new electric power plants has been a major focus of the preservation versus development controversy, and a harbinger of the growing importance of the land use issue. Both the level and pattern of utilization of existing capacity, and the rate and composition of additional capacity, are therefore critical to environmental policy.

Our laws and institutions are built around the presumption that, unless there is good reason to believe otherwise, markets and market-determined prices are the best arbiters of both output and investment decisions. The rationale for that presumption is very simple: under certain conditions, market prices equal "social costs". Under these conditions each consumer, in deciding whether or not to take an additional unit of the good in question, knows that he must pay the full costs that society will incur in producing that additional unit of the commodity. Markets and prices then guide us to a situation in which each consumer (and therefore society) takes only as much of the commodity as he (and therefore we) are willing to pay for.

Two kinds of “conditions” are necessary to this result. First, economies of scale must be exhausted with firm sizes much smaller than market demand: otherwise one firm will grow to dominate the entire market, and there will not be any competition between firms. Second, there must be no externalities, so that the costs to the firm of producing a unit of the commodity reflect the full costs thereby imposed upon society.

Both of these conditions are violated in the case of electric power. This simultaneous violation has brought the issue of electricity rates to the forefront of environmental controversy. The first condition is violated by economies of scale in the generation and distribtuion of electric power: it is cheaper per KWH to supply more KWHs up to and beyond the number of KWHs taken in large markets. Consequently, we have devised the social institution of regulated monopoly: electric power companies are given a monopoly of their service areas, so that society may reap the benefits of scale economies. And they are regulated--their pricing and investment deicions are subject to the approval of public authorities--in order to spare us the potential dangers of monopoly power.

The second condition is violated by the familiar “external diseconomies” of power generation--air and thermal pollution. Some associated costs, for example the health costs of air pollution, are not seen as costs by power companies, and therefore do not enter into the determination of prices.

The well-known solution to this second problem is to "internalize" external costs: in the last example, this requires adding the health costs of air pollution to the internal production costs of the polluting firm. Health costs will then be reflected in prices, thereby restoring a rough equality between price and social costs.

The implementation of this simple prescription faces severe difficulties of practice. For, as we have emphasized above electric power prices are regulated monopoly prices, set in order to guarantee a "fair" return on capital. Consequently it cannot be assumed that some simple adjustment of existing prices will equate price and social cost. And there is a further serious difficulty: the internal costs of power production are rather complex.

A major source of that complexity is associated with the "peak load" problem. In the early hours of the day much system capacity is sitting idle, so that the costs which an additional user imposes upon society are essentially only the cost of the fuel required to generate enough electricity to meet that user’s demand. But at some hour of the day the demands of residential, commercial and industrial electricity customers will inevitably approach system capacity. All customers taking power at those peak hours will, collectively, be imposing upon society, the full capital costs of system capacity. The costs of serving these users therefore include both fuel (or operating) cost and capital costs.

Our purpose in this study is to take two essential steps in the direction of a rationalization of the pricing of electricity: first, an examination of the relationship between existing prices and internal costs, and second, a quantification of the potential benefits to be derived from the redesign of rate structures. In this Executive Summary we will begin with a highly simplified conceptualization of the problem. Then, bit by bit, we will introduce the complexities and data difficulties which have forced us to imputation, approximation, or estimation. Finally, we shall discuss the results of our empirical work, and the policy implications of those results.

CONCEPTUALIZATION OF THE PROBLEM

Consider Figure 3 of the report text, reproduced below. That figure illustrates the distortions which arise from failing to charge different offpeak and peak prices for a commodity subject to a peak load problem. A peak load problem arises whenever demand fluctuates much more rapidly than the time in which capacity can be adjusted to demand. (In the case of electric power, demand varies sharply over the working day, while capacity takes years to plan and build.) At the single price P, offpeak customers take $KWH_{Offpeak}$ and peak customers take KWH_{Peak}, with these quantities defined by the intersections of the P line and the offpeak and peak demand curves.

The problem with this method of pricing electricity is that it is inefficient. Economic efficiency requires that every customer pay the full incremental resource costs his consumption imposes upon society, no more and no less. Depreciation

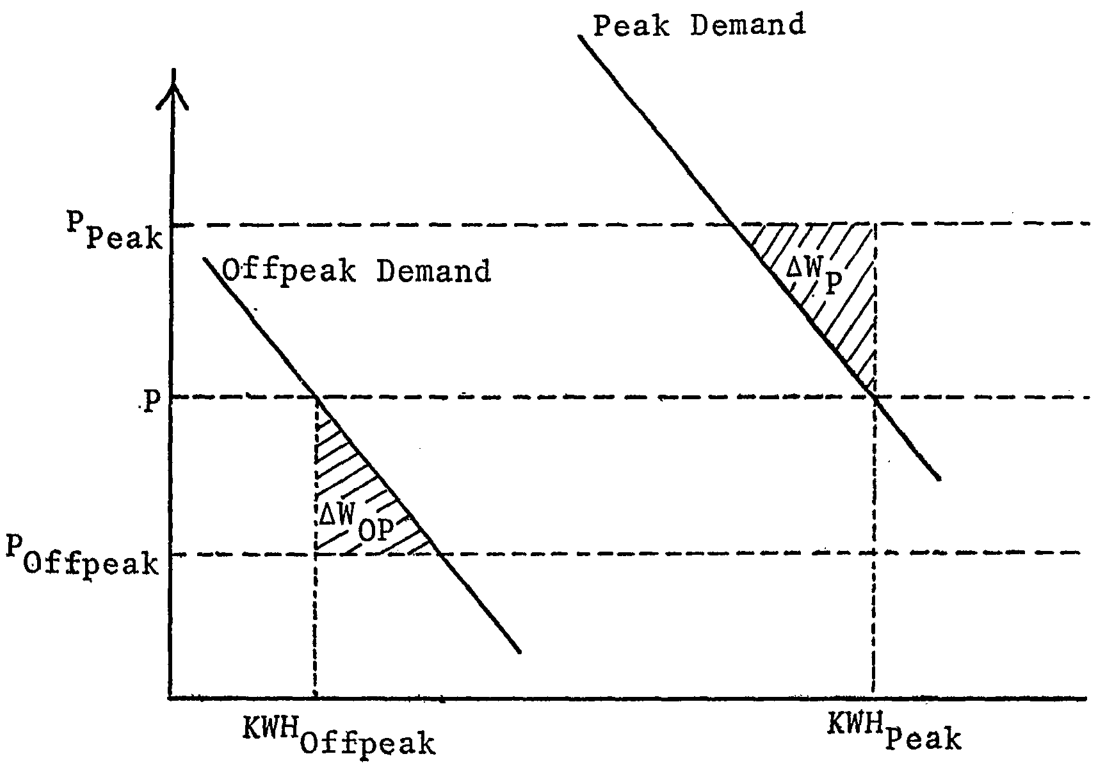

Figure 3. Welfare Gains from Peak Load Pricing

is a resource cost, and the peak load pricing problem is essentially a problem in assigning responsibility for depreciation or the maintenance of capacity; A priori, it may appear that because there is excess capacity during offpeak hours, offpeak users impose no incremental capacity costs upon society, More generating capacity need not be built in order to serve these users: in fact, equipment could be allowed to deteriorate slightly, capacity could be reduced, and offpeak demand could still be met. Thus, it may appear that because capacity is not scarce during offpeak hours, the price paid by offpeak users should not include a charge for depreciation. Further, it may also appear that since capacity must be maintained in order to meet the demands of peak hour users, it is they who must pay a charge sufficient to cover depreciation.

This solution is not entirely correct. Depreciation takes two forms: that associated with use and that which is independent of use. Any depreciation resulting from use constitutes a resource cost imposed upon society by that user. In the case of an electrical utility capacity is scarce during peak hours, and if depreciation occurs when electricity is supplied to offpeak users, then a scarce resource has been used up, a resource cost has been imposed upon society, and the price charged to offpeak users should legitimately include a charge for this depreciation. Obviously the same holds for any depreciation associated with use by peak hour users.

The situtation is quite different for depreciation which cannot be attributed to use. Since offpeak users are neither contributing to such depreciation nor demanding that capacity be maintained, they are not imposing a resource cost on society, and the price which they pay should not reflect this type of depreciation. However, if peak hour demands for power are to be met, capacity must be maintained. Although peak hour users cannot be said to be causing non-use depreciation, their demand for electricity implies the need to maintain capacity and imposes a resource cost on society. Hence the price charged these peak users must be sufficient to cover both use and non-use depreciation, normal return on investment, and incremental operating costs.

Since most depreciation in the electrical utility industry is not attributable to use, the efficient prices are $P_{Offpeak}$ to offpeak users, where $P_{Offpeak}$ is equal to the incremental operating costs of serving these users, and P_{Peak} to on peak users, where P_{Peak} is the sum of incremental operating costs and incremental capacity cost.

The shaded areas in Figure 3 represent the losses to society from incorrectly pricing the commodity at P. At price P, offpeak users are being denied consumption which they value more than the resource costs ($P_{Offpeak}$) that consumption would impose upon society, and ΔW_{OP} is the magnitude of those losses. Similarly, at price P peak users are being charged less than the resource costs (P_{Peak}) they impose upon society by their consumption, and the area ΔW_P represents the social gain available if current price P is raised to P_{Peak}, there eliminating inefficient consumption. Correct pricing will give net social benefits equal to $\Delta W_{OP} + \Delta W_P$.

DIFFICULTIES OF IMPLEMENTATION

Implementation of this scheme runs up against many practical difficulties, and here we set out the most prominent, together with some comments on their resolution.

Demand

In Figure 3, we have drawn two demand curves, one for the offpeak hours of the day and one for the peak hours of the day. The demand for electric power fluctuates over the 24 hour daily cycle, and we have taken as "the" peak period of every 24 hour day that eight hour period in which the largest KWH total is generated. (Electricity demand also exhibits a seasonal peak, with average daily consumption peaking in some month of the year. This seasonal peaking problem will concern us later; our focus here is on the daily peak.)

In order to compute the potential welfare gains ΔW_{OP} and ΔW_P, we need to know how much offpeak and peak demands change as offpeak and peak prices change. The technical term for the required measure of price sensitivity is price elasticity: the information we require is offpeak and peak price elasticities. But existing studies of the price elasticity of the demand for electricity generally estimate the price elasticity of total demand--offpeak plus peak demand--and do not try to estimate the price elasticities of off-peak and peak demand separately. We were therefore forced to use the best of recent studies of overall demand elasticity, and to assume that peak demand is independent of offpeak price--and vice versa. The latter assumption is uncomfortable, especially in the long run, since there would almost certainly be some shifting in temporal patterns of electricity consumption in response to relative price changes. Moreover, it is the long run--the time span in which capacity can be adjusted--that interests us most. The welfare gain ΔW_P in Figure 3 arises in part because society is spared the incurrence of the costs of provision of some inefficient capacity, and that capacity adjustment can only be made in the long run. Note that were prices off peak lowered so as to capture the welfare gain ΔW_{OP}, electricity consumption offpeak would be increased--as would be environmental degradation, the costs of which are not counted in ΔW_{OP}. For these reasons, we have, in our welfare gain estimates, used ΔW_P, which can be used without reservation as a lower bound welfare gain estimate. After a survey of available econometric elasticity estimates we adopted those of Chapman, et. al., because of the exceptional quality of their econometric work and their estimation, on a comparable basis, of elasticities by customer class (residential, commercial, and industrial) and by state. Their long run elasticity estimates are roughly equal to one.

Cost

In figure 3 we have drawn two horizontal lines at $P_{Offpeak}$ and P_{Peak}, and these represent the incremental cost of serving offpeak and peak users respectively. That simple representation covers a multitude of conceptual and empirical difficulties in the estimation of these incremental costs.

The offpeak incremental costs of delivering an additional KWH to a customer are relatively easy to estimate, since the are essentially the fuel cost of generating an additional KW Strictly speaking, that cost is different from hour to hour, for every electric utility has a stock of generating units c various ages and sizes. Typically, the older and smaller units are less efficient, and in order to minimize operating cost, the units are brought on line in ascending cost order. At any moment, the offpeak incremental cost of delivering an additional KWH is therefore approximately equal to the generation costs of the least efficient unit operating at that moment. Further, it costs more to deliver a KWH to a residential customer than to an industrial customer, since there ar energy losses in the low voltage distribution system serving residential customers. But these differences are relatively small, and we have taken average fuel cost as an approximate measure of the offpeak cost of delivering a KWH.

The peak incremental costs of delivering an additional KWH to a customer are much more difficult to estimate, since that requires the allocation of capacity costs among customer classes. There is inevitably some arbitrariness in these allocations, but our exploration of a range of reasonable procedures led to little quantitative variation in results.

Pricing

Our purposes in making estimates of the costs incurred in serving offpeak and peak customers of various types (residential, commercial and industrial) are two: first, to allow us to compare present prices charged for each of these kinds of service with the costs incurred in providing that service; and, second, given that comparison, to suggest improvements in rates--methods of pricing electricity--which will better approximate price cost. We therefore turn to a summary of our treatment of the pricing problem.

In Figure 3, a single horizontal line P represents the present price of electricity. The reality is more complex; electricity is generally priced at a quantity discount, in so-called declining block rates. Any customer taking a specified amount of energy under a schedule is paying some definite marginal price and some definite average price, but he is not paying any single price. In order to quantify his sensitivity to price changes, we need to know what kind of changes he is sensitive to--marginal, average, or both.

There is no firm basis for asserting that, e.g., residential customers are responsive only to average prices or that industrial customers will shift their time profile of electricity consumption in response to price differentials between peak and offpeak. But a reasonable argument can be made for such a typology of customers.

Assume that every consumer reacts optimally to the options open to him. Then any consumer of electricity will allocate time to the electricity consumption decision to the point where marginal benefits of such time--the reduction in electric bill resulting from the incremental minute spent in making the electricity consumption decision-- just equal the incremental costs involved (in this case, the value of the incremental minute in its next most valuable use). The outcomes of this allocation decision process will be classified in two dimensions: time differentiating versus time-undifferentiating consumption decisions, and average price responsive versus marginal price responsive consumption decisions. Table 7 of the text sets out this typology, and is reproduce below.

Table 7. A TYPOLOGY OF ELECTRICITY CUSTOMERS

	Time Undifferentiating	Time Differentiating
Average Price Responsive	I	II
Marginal Price Responsive	III	IV

Customers in Category I have found it optimal not to distinguish between average and marginal prices in their electricity consumption decisions. For these customers, the existence of block rates is irrelevant, since they would make the same consumption decision at a flat price equal to the average revenue they are currently paying. Customers in Category II elect to pay the cost of differentiating between their consumption on and offpeak by paying the additional costs of metering peak and offpeak consumption separately. By assumption, they are insensitive to any differential between average and marginal prices on peak, and to any differential between average and marginal prices off peak. They do distinguish between average peak period price and average offpeak price.

Customers in Category III do not find it optimal to distinguish between peak and offpeak consumption, but they find it optimal to distinguish between marginal and average price. Finally, customers in Category IV find it optimal to distinguish between consumption in both dimensions: between power taken off peak and at peak, and between average and marginal prices paid for electricity.

So much for typology: which kinds of customers belong where? There are no unambiguous guidelines. Thus, it is not entirely clear that all customers on a given.rate schedule belong in a single category. Large residential users, for example, may have some marginal price sensitivity and may therefore belong in Category III, whereas very small residential users almost certainly belong in Category I.

Our identifications of rate schedules with categories of the above typology are as follows.

<u>Category I</u>

This category is the domain of small residential and commercial users. The relevant question regarding possible improvement in rate structures is then restricted by the assumptions that consumers in this category do not, for information cost reasons, distinguish either marginal and average price or off peak and peak consumption. The only remaining policy quest is then as follows: how much "better" can we do by changing the average KWH prices paid by customers on individual rate schedules? For example, how much better can we do, in terms of our welfare measures, by slightly raising the average price per KWH paid by commercial customers, and by simultaneously slightly lowering the average price per KWH paid by industrial customers? To the extent that the derived quantitative measures are reliable, they indicate that available gains are ligibly small.

Category II

We will compute net benefit measures for all rate schedules the sample companies as if it were the case that customers average-price responsive--that they have found it optimal n to distringuish between peak and offpeak consumption. For residential customers, presently metered on. a KWH monthly or bimonthly basis, this will require netting of the additional cost of double-rate registers required to charge differential rates off peak and on peak. A warning regarding the full spectrum of benefits and costs for double rate register metering is in order: there is a potentially serious drawback to do rate register metering of offpeak and peak hours. Should service to a given area be interrupted and restored in any time interval not a multiple of 24 hours, the correct setting of the double rate register shall have been lost. It would be necessary to meter on a KWH basis, taking the simple summary of the offpeak and peak registers as the relevant number of KWH, until the time at which the meter was read; at that time the reader could, reset the device. The evaluation of this problem is beyond the scope of this report.

Category III

The prime candidates for Category III are large residential users if it is assumed that, for some reason, there is no possibility of differentiating between offpeak and peak usage for these customers. Again, recall that all customers on a given rate schedule need not necessarily fall into the same category of our typology. Nevertheless, as we will see in our analysis of Category I, there is little to be gained from pricing changes which do not discriminate between off-peak and onpeak consumption. However, there is still the possibility of "implicitly" differentiating between offpeak and peak, and our major estimate corresponding to Category III is the estimation of an upper bound on the gains attainable from implicit differentiation. How might this work? Suppose that some electric utility had a declining block rate schedule with two blocks, with the tailblock lower than the first block. Suppose further that tailblock customers buy all their electricity on peak, while first block customers buy all their electricity off peak. Then we can in some measure simulate peak load pricing by raising the tail-block and lowering the first block. Advocates of "rate inversion" often argue for something like this, and we will calculate a rough upper bound on the potential welfare gains associated with one kind of rate inversion proposal.

Category IV

In Category IV we place our large commercial and industrial users. They incur little incremental expense in differentiating betwen their consumption off peak and on peak, since utilities generally know the instantaneous load being pulled by their individual large customers, and those customers generally know the loads they are pulling. Some of these customers also have that information. Similarly, there is little incremental expense to be incurred by a "switch" from average price sensitivity to marginal price sensitivity: so long as someone is watching the electric bill, the additional cost of watching it in a slightly different way is negligible For these customers, a relevant benefit/cost question is: what is the magnitude of the gains likely to be had from time differentiated pricing, e.g., a better matching of peak peri (perceived) prices and costs? Some technical problems make this comparison less than straightforward. But we shall see that it can be made, and that the attainable gains are probably substantial.

External Costs and Welfare Gain Measures

All of the costs we have described are strictly internal to the firm. The welfare gain measures depicted as the shaded areas of Figure 3 are constructed on the assumption that the horizontal lines $P_{Offpeak}$ and P_{Peak} reflect all the incremental costs of offpeak or peak consumption, and since lowering the offpeak price will expand offpeak consumption and the corresponding external costs, we cannot confidently assert that we gain ΔW_{OP} by such a change in price. But raising the price of peak electricity restrains peak consumption, and spares us both ΔW_P in welfare loss and the associated external costs. Consequently, the welfare gain measures we report ar our evaluations of ΔW_P alone.

WELFARE GAIN ESTIMATES

Category I

The evaluation of several welfare gain measures subject to the stringent assumptions defining this category--that customers are average price responsive and do not distinguish between offpeak and peak consumption--gave negligible benefit estimates. This line of work was pursued no further.

Category II

Customers in this category were assumed to distinguish between offpeak and peak consumption, but not between average and marginal price. In terms of Figure 3, we need $P_{Offpeak}$ and P_{Peak} for each customer class, and we take for demand elasticities the average price demand elasticities reported in econometric studies. For residential customers, we must remember that additional metering costs will be imposed if we distinguish off peak and peak, so that for this customer class these costs must be netted from benefits.

For each electric utility and for each rate schedule, two kinds; of ΔW_P were computed. The first of these measures is the gain to be derived from a peak period price increase which diminishes peak consumption by 10 percent; the second is the gain associated with peak prices equal to full peak costs.

The numerical results obtained are fairly consistent across our sample of electric utilities. The estimate of ΔW_P based upon a 10 percent decrease in peak consumption was generally a small dollar figure, of the order of hundreds of thousands of dollars. The estimate based upon full peak cost was typically a much larger dollar figure, of the order of millions or tens of millions of dollars. We believe that a reasonable interpretation of this divergence is as follows. The analysis determination of the "true" figure somehow must attach weigh to these two bounds, and those weights are unavoidably judge mental. Our inclination, based upon our experience with the cost data, is to favor the higher estimate: that expected social returns to the full cost pricing of peak power are substantial.

Category III

Customers in Category III are assumed not to distinguish between offpeak and peak consumption, but to be marginal rather than average price responsive. Large residential customers are prototypical of this category. The best hope of simulating an offpeak versus peak price differential to these customers is to exploit whatever correlation there may be between monthly consumption and load pattern. It is widely suspected that tailblock customers--customers with high monthly consumption--take a disproportionate amount of their electricity on peak. Studies to test this hypothesis are only now being do by many major systems, and some private communications of priliminary results lend support to the idea.

In order to estimate the potential social gains from a serious attempt to use the block rate structure to simulate offpeak-peak differentials, we have made an extreme assumption and computed benefits on the basis of that assumption. We assume that all tailblock consumption is on peak, and we estimate the benefits associated with raising the tailblock prices to the level of the first block price. The proposal has been one frequently advanced by advocates of so called rate inversion.

For all electric utilities in the sample, the resulting welfare gain estimates are of the order of millions of dollars. The policy implications seem clear: the expected social gains from the use of residential rate block load curve information to simulate peak period pricing are substantial. Nevertheless, this method must be inferior to direct peak period pricing via double register metering.

<u>Category IV</u>

Recall that customers in Category IV are assumed to be both marginal price responsive and to be able to distinguish between offpeak and peak consumption. Estimates of the potential social gain ΔW_P from correct pricing of peak electricity can then be derived as follows. From the existing rate structures filed by the individual companies, we can determine what commercial and industrial customers actually pay for power taken during peak hours: this corresponds to a determination of P in Figure 3 above. From our estimates of the cost of providing peak power to these customers, we have an estimate of P_{Peak} in Figure 3. And finally, use of our econometric estimates of average price demand elasticities together with the relationship between average and marginal price elasticities gives us an estimate, by state and customer class, of marginal price elasticities.

The evaluation of ΔW_P by system, season, and customer class is then routine, and the results are compiled in Column 9 of Table 46. The dollar estimates of potential gain are large for all systems. The policy implication is again clear: there are large benefits to be expected from movement towards a system of peak pricing of large commercial and industrial consumption.

We conclude this executive summary with a brief recapitulation of our conclusions and recommendations.

CONCLUSIONS

The major discrepancy between cost to the power company and price charged the user is associated with the large difference between the costs of serving offpeak and peak customers and the failure of existing rate schedules to reflect that cost differential in different prices. Each customer class (residential, commercial, industrial) has distinctive characteristics which must be considered in evaluating proposals for better reflecting the offpeak versus peak cost differential in prices. For all customer classes, there are probably large net benefits to be derived from doing so.

For residential and small commercial customers, there are two ways in which the price differential between offpeak and peak power can be communicated to the customer. First, by double register metering, the customer's actual consumption can be metered separately off peak and on peak.

Second, customer load curve surveys can provide information on the contribution of customers in the different blocks of the system's block rate structure, and that information can be used by the system to approximate an offpeak versus peak price differential. Estimates of the potential benefits to be derived indicate that both methods would be a substantial improvement over current pricing practice; direct double register metering, a "first-best" peak pricing method, is preferable to "second-best" methods based upon rate block load curves.

For large commercial and industrial customers, the change-over to a pricing system reflecting the offpeak versus peak cost differential would not require major changes in utility practice, since companies generally monitor these customers' loads individually and on a half hourly or hourly basis. Estimates of the potential benefits to be derived from such a changeover indicate that they are substantial.

RECOMMENDATIONS

Two kinds of recommendations follow from our work. First, there are policy recommendations which can be made based on what can be learned from existing data. Second, there are recommendations for improving the data base upon which all rate making rests.

Residential and small commercial customers can and should be metered with double rate meters. It is of particular importance that peak hour prices be brought into closer alignment with peak hour costs.

Large commercial and industrial customers can and should be charged rates which distinguish between peak hour and off-peak hours.

For all classes of customers, there are relatively simple ways of quantifying the cost differential between offpeak and peak power. A quantification of this difference should be required in rate proceedings before public utility commissions, and it should be incumbent upon a system applying for a rate increase to demonstrate that there is no better way to reflect the offpeak versus peak hour cost differential in prices.

Public service commissions should require that companies do the demand elasticity studies that can easily be done with data every system accumulates in the course of time, i.e., customer bill histories.

Public service commissions should require that companies do customer class load curve studies, in order to establish the contribution each customer class makes to the system peak in each season.

Public service commissions should require that, if the block rate structure based upon monthly consumption is to be retained for residential and small commercial customers, then the company in question do customer surveys of customers in individual blocks, so that the contribution of each block to the system peak can be established.

SECTION I

CONCLUSIONS, RECOMMENDATIONS AND INTRODUCTION

CONCLUSIONS

Central to the evaluation of any industry is the relationship between internal production cost and selling price: price, the amount a potential consumer must sacrifice for another unit of consumption, must equal the cost that production of that last unit imposes upon society, otherwise resources are being misallocated.

In the case of the electric power industry, there are two special circumstances which make the comparison of price and social cost somewhat difficult. First, there are high external costs associated with the thermal generation of electric power: thus air pollutants impose health costs, but those health costs are borne by individuals and not by the power company. Second, electric utilities are regulated monopolie whose price and investment policies are publicly regulated, so that even the relationship between price and internal cost is not what it is in competitive sectors of the economy.

This study was motivated by the first of these two special circumstances, i.e., high external costs. But our emphasis is almost entirely upon the second--the fact of regulation--and our objective is a better understanding of the relationship between price and internal cost. We believe that a clever understanding of that relationship is an essential step towards the rationalization of pricing and capacity decisions in the industry.

We find that the major discrepancy between internal cost and price arises from the sharp cost differences between peak and offpeak electric power and the failure of most existing electric rate schedules to reflect that cost differential. Each customer class--residential, commercial, and industrial--has distinctive characteristics which must be considered in evaluating proposals for reflecting that cost differential in prices. For all customer classes, however, there are probably large benefits to be derived from doing so.

For residential and small commercial customers, there are two ways in which the price differential between offpeak and peak power can be communicated to the customer. First, by double register metering in which the customer's actual consumption is metered separately offpeak and on peak. Second, customer load curve surveys can provide information on the contribution of customers in the different blocks of the system’s block rate structure, and that information can be used by the system to approximate an offpeak versus peak price differential. Estimates of the potential benefits to be derived indicate that both methods would be a substantial improvement over current pricing practice.

For large commercial and industrial customers, the changeover to a pricing system reflecting the offpeak versus peak cost differential would not require major changes in utility practice, since companies generally monitor these customers' loads individually and on a half hourly or hourly basis. Estimates of the potential benefits to be derived from such a changeover indicate that they are substantial.

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INTRODUCTION

The Overall Framework

This study was undertaken in the hope of obtaining a more dependable and quantitative grasp of a related set of problems critical to environmental management. At the center of that set of problems is the pricing "policy" of the electric power industry. It is no longer necessary to discuss the importance of energy in general, and electricity in particular, in environmental management. Our concern is with one possible dimension of that set of problems: the possibility that they are either exacerbated or made more intractable or both because of the way in which electric power is priced.

It is a well-known principle of welfare economics, now widely absorbed into the conventional wisdom, that perfectly competitive markets guarantee a result--in terms of price, the level of output, and the level of capacity in the industry--which in some sense is the best possible--the optimal--result Crudely, this means that no customer who values the particular good or service at least as highly as the social opportunity cost of satisfying his demand is left unsatisfied: that, at the margin, the last customer is paying exactly the costs he imposes upon society for the incremental unit Of output. The usefulness of the competitive model in public policy analysis arises because, in those situations requiring measurement of departures from optimum performance. The model suggests tho policies most likely to nudge an imperfect market towards the competitive outcome.

Turning to the electric power industry, which departures from Competitive industry structure: are most likely to lead to suboptimal performance? Electric power is a regulated industry, and the conventional rationale for regulation rests upon a feature of the industry which rules out a competitive industry structure. Usually referred to as long run decreasing average costs, the essence of this problem is that there are economies of scale over the whole range of the market--that more of the market of the typical electric utility is served by a single utility, up to the extent of the market, larger plants with lower unit costs can be used, and the market served at lower cost. It would impose needlessly high costs of power production upon consumers of electricity to allow more than one producer of electricity to serve the market. Thus our resort to regulated monopoly in the provision of electric power. Next, the market failure associated with external costs is of obvious relevance to the electric power industry. The best known of these is the emission of particulates and of noxious gases into the ambient air during the process of combustion. To the extent that final product price- -in this case, the price of electricity to the final user--does not adequately reflect the full social costs of production, actual industry output can be expected to be larger than the social optimum.

The solutions to the departures from competitive optimum which arise from long run decreasing costs and from external costs have become almost as well known as the problems themselves. For the first, the welfare economist prescribes regulated monopoly, with prices equal to marginal cost and the resulting deficit covered by a subsidy or, if the enterprise is constrained to balance its budget, so-called second-best marginal cost pricing: prices which depart from marginal cost so as to minimize the resulting distortion of consumption patterns from optimum. And for external costs, the well-known prescription is internalization. Through effluent fees or equivalent devices, producers must be made to feel the full social costs imposed by their production processes; prices, communicated to consumers, become correct signals to those consumers of the resource costs imposed upon society by their consumption decisions.

It would seem that, in applied work, we need only examine particular industries with these standards, and shape policy recommendations in accord with these standardized correctives Sadly, things are infinitely more complicated, and especially so in the case of the electric power industry. As elsewhere, we do not have an accurate measure of the social costs of the environmental impacts associated with the industry as a whole let alone with particular companies or with particular plants As elsewhere, we do not have certain but rather only hazy knowledge of demand conditions; worse, demand varies rapidly over time--there is a "peak load" problem--so that our crude measures of demand are even further removed than usual from the underlying reality.

But the applied welfare economist is used to this sort of adversity. There is no excuse for defeatism. There can be no precise determination of "the" optimum of welfare theory. But intelligent conceptual and empirical work can guide us in the identification of inefficient aspects of present policies, and can establish where the main chances for improvement lie.

That conceptual and emprical work proceeds through the body of the report. In Section II, we review econometric work on electricity demand, with an eye less on a comprehensive recapitulation of this literature than on the selection from that literature of a set of demand elasticities which, much later in Section IV, enter directly into welfare estimates. In Section III, we enter into the cost side of power production, again with the same limited objective: the derivation of cost measures required for those welfare estimates. Finally, in Section IV, come the estimates themselves. The remainder of this Introduction treats a problem of relevance to every portion of the report, the selection of a sample of companies used in the empirical work done in later Sections.

SELECTION OF A SAMPLE OF COMPANIES

Our sample of systems should be representative in at least the following senses:

Clearly it should be representative of the ownership structure of the industry. In 1970, the approximately 250 investor-owned systems generated roughly 80 percent of total continental United States net generation. There are, of course, publicly-owned systems with significant generating capacity, e.g., the Tennessee Valley Authority. But, our focus in this study is upon pricing practices common to public and private sectors of the power industry. We have therefore restricted our sample to Class A investor-owned utilities, utilities having annual electric revenues of $2,500,000 or more.

Further, our sample should be representative of the variation in cost structure found within the industry. If we are to measure the success or failure of the industry in tailoring rates to cost, the full variation in cost conditions should be represented. Two of many determinants of the cost structure of electric service are location and load pattern. There are sharp regional variations in cost structure associated with the availability or unavailability of cheap hydroelectric or cheap competitive public power. The nature of the market--the mix of residential, commercial, and industrial markets, and the specific time pattern exhibited by each of these loads--varies between regions. For example, Southern systems have in recent years typically become summer peak systems, with maximum system load tied to the growth of the air conditioning load.

Thus much of the variation across systems is ultimately regional in nature, and our selection process was designed accordingly. First, all Class A companies were assigned to Federal Power Commission, in part, in order to divide the. contiguous United States into regions of roughly similar cost and load characteristics. Next, the systems within each region were cross-classified with respect to capacity, by timing and size of system peak, and as combination* or noncombination utilities. From this classification we selected

Combination utilities sell both gas and electricity; noncombination electric utilities sell only electric energy.

38 systems, distributed over the regions in rough conformity with the distribution of system characteristics within each region. All of those 38 systems were contacted, and the 10 systems which seemed most disposed towards cooperation with the study then became the study sample.

In this report, full results are presented for five systems. Even this small sample embraces considerable geographic diversity and therefore considerable variation in cost and load conditions. This should be kept in mind through all of what follows. We feel that a good sign that our procedures are relatively robust against many of the inevitable arbitrary assumptions and imputations employed along the way is the uniformity--in order of magnitude terms--of results across the sample.

SECTION II

THE DEMAND FOR ELECTRIC POWER

Any comparison or ranking of rate structures depends, ultimately, upon knowledge of cost structure and of demand. Implicit in every argument over rates is some disagreement over either cost or demand or both. We would suggest that the electric utility industry has, on the whole, better explored the cost side than the demand side, and for obvious reasons: utility expenses are registered as tangible dollar outflows, while the economically relevant measure of demand must be reconstructed from a quantity measure, instantaneous system load.

In our discussion of rate making, we will necessarily resort to a hedged dependence upon the results of econometric studies of demand. The hedging is required, in part, by Henri Theil's dictum that models are to be used, but not necessarily believed. More seriously, the elasticities critical to rate making--the elasticities of (daily) offpeak and peak demand for electricity--have never been directly estimated. In view of these constraints, our purpose in this chapter is not a comprehensive view of the econometric demand literature but rather an assessment of the conceptual differences underlying the various estimates, a defensible rationale for our ultimate choice of elasticities, and a working knowledge of their limitations.

THE ECONOMETRIC EVIDENCE

In the course of our discussion of the econometric evidence we refer to several tables summarizing the scope, method and empirical results obtained in the major papers. Table 1 is cross comparison of markets studied and the nature of the data-base. Table 2 enumerates and defines the relevant variables and specifies the units in which they are measured. Table 3 provides a comparison of regression results obtained by the various authors in estimation of constant-elasticity equations for residential demand, so that all variables are to be thought of as natural logarithms: thus $KWH_t(s,b;\alpha)$ refer to the natural logarithm of the number of thousands of KWH sold, in period t, to customers in block b, of rate schedule s, in region α. We proceed to a general discussion of the numerous places at which an econometric study of electricity demand must make essentially judgmental choices. Subsequently, in our discussion of the individual papers, we will examine the choices made by some individual investigators.

ECONOMETRIC ESTIMATION OF ELECTRICITY DEMAND: GENERAL PROBLEMS

To begin at the beginning, the theory of consumer behavior tells us that demand for any commodity depends upon the price of that commodity, upon income, and upon the prices of all other commodities. A glance at that formulation suggests the difficulties of application to the electric power case. In order of descending intractability these are:

(a) The definition of price: electricity is characteristically sold at block rates, i.e., at a quantity discount, so that there is no one "price." Stated in another way, marginal price and average price differ, in contrast to the situation, for

Table 1. AN OVERVIEW OF THE CENTRAL ECONOMETRIC PAPERS ON ELECTRICITY DEMAND[a]

Paper	Model	Markets Studied			Data Base		Remarks
		Residential	Commerical	Industrial	Cross Section	Time Series	
(Fisher and Kaysen, 1962)	Residential Industrial	X		X	47 State data	1946-1957	
(Halvorsen, 1971)		X			48 Contiguous state data for all variables except MJTEMP	1961-1969, inclusive, for each state	MJTEMP time series (for each state) developed as: average of MJTEMP for three largest cities in that state
(Wilson, 1971)	I; pp. 11-13	X			77 Cities		Utility price, quantity data based upon utility service areas
	II; pp. 13-16	X			83 SMSA's		
(Baxter and Rees, 1968)				X		1954-1964 Quarterly data on 16 British industry groups	
(Anderson, 1971)				X	48 Contiguous state data for SIC primary metals industry	31 states in 1958; 29 states in 1962	A unified energy supply-demand model
(Chapman et. al., 1973)		X	X	X	48 Contiguous state data	1946-1970 inclusive	MJTEMP series (for each state) taken as mean January temperature for largest city in each state
(Smith et. al., 1973)		X	X	X	7 New York State utilties	1951-1970	

[a] *References are compiled at the end of the report.*

Table 2. VARIABLES, UNITS, AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND FOR ELECTRICITY

	Variable	Unit	Definition
Quantity and Other Independent Variables	$KWH_t[s,b;\alpha]$	10^3KWH per period	KWH sales to customers in block b of rate schedule s, in the t^{th} period, in region α
	$KWH_t[s;\alpha]$	"	KWH sales to customers on schedule s in period t, in region α.
	$\frac{KWH_t[s,b;\alpha]}{B_t[s, b;\alpha]}$	"	KWH sales per customer in block b of rate schedule s in the t^{th} period, in rate' schedule a
	$KWH/HH_t[s;\alpha]$	"	KWH sales per household on rate schedule s, in the t^{th} period, in region α
	$KWH/B_t[s;\alpha]$	"	KWH sales per customer on rate schedule s, in the t^{th} period, in region α
	$PCTAP\underline{X}_t[\alpha]$		Percent of homes in service area (roughly coincident with region α) with at least one unit of applicance installed, in the t^{th} period

Table 2 (continued). VARIABLES, UNITS, AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND FOR ELECTRICITY

	Variable	Unit	Definition
Dependent Variables: Own-Price	$NOMREV_t[s,b;\alpha]$	Cents per KWH	Nominal revenue per KWH for customers in block b of schedule s, in the t^{th} period, in region α
	$NOMREV_t[s;\alpha]$	"	Nominal revenue per KWH for customers on schedule s, in the t^{th} period, in region α
	$NMQREV_t[s,b;\alpha]$	"	Nominal marginal revenue for customers in bloc b of schedule s, in the t^{th} period, in region α
	$REREV_t[s,b;\alpha]$		Real revenue per KWH for customers in block b of schedule s, in the t^{th} period, in region α
	$REREV_t[s;\alpha]$		Real revenue per KWH for customers on schedule s, in the t^{th} period, in region α
	$RMQREV_t[s,b;\alpha]$		Real marginal revenue for customers in block b of schedule s, in the t^{th} period, in region α
	$FPC_t[s,500,\alpha]$		Federal Power Commission typical bill for, e.g.., customers on schedule s, in the t^{th} period, in region α, taking 500 KWH per month

Table 2 (continued). VARIABLES. UNITS, AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND FOR ELECTRICITY

	Variable	Unit	Definition
Dependent Variables: Prices of Close Substitutes	$NOMNG_t[r;\alpha]$	Cents per Therm	Nominal revenue per therm for natural gas customers, on rate schedule r, in the t^{th} period, in region α
	$RENG_t[r;]$	"	Real revenue per therm for natural gas customers
	$NOMDIS_t[\alpha]$	Dollars per Barrel	Nominal price of distillate oil, in the t^{th} period, in region α
	$CPIEL_t$		Consumer price index for electricity in the t^{th} period
	$CPING_t$		Consumer price index for natural gas in the t^{th} period
	CPI_t		General consumer price index in the t^{th} period
Dependent Variables: Income	$MFY_t[\alpha]$	Dollars per Year	Median family income, in the t^{th} period, in region α
	$MHEMFG_t[\alpha]$	Dollars per Hour	Average hourly earnings in manufacturing
	$DPIPC_t[\alpha]$	Dollars per Year per Capita	Disposable personal income per capita
Other Variables: Demographic	$POP_t[\alpha]$	Thousands	Population of region α in the t^{th} period
	$PCTURB_t[\alpha]$		Percent of α^{th} region living in in urban areas in the t^{th}

Table 2 (continued). VARIABLES, UNITS, AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND FOR ELECTRICITY

	Variable	Unit	Definition
Other Variables: Demographic (continued)	$HS/HH_t[\alpha]$		Number of houses per household, in the $t^{\underline{th}}$ period, in region α
	$BPC_t[s;\alpha]$		Number of customers per capita on rate schedule s, in the $t^{\underline{th}}$ period, in region α
	$R/HSE_t[\alpha]$	Rooms per House	Average size of housing units
Other Variables: Market Characteristic Variables	$B_t[s,b;\alpha]$		Number of bills in block b of schedule s, in the $t^{\underline{th}}$ period, in region α
	$B_t[s;\alpha]$		Number of bills in rate schedule s, in the $t^{\underline{th}}$ period, in region α
	$PCTPVT_t[\alpha]$		Percent of total region α generation by investor-owned electric utilities
	$FUELSG_t[\alpha]$	Cents per 10^6 BTU	Cost of fuel consumed, in cents per 10^6 BTU, times the percent of total net generation (in the $t^{\underline{th}}$ period) by thermal plants
	$R/IS_t[\alpha]$		Ratio of total residential KWH sales to total industtrial KWH sales

Table 2 (continued). VARIABLES, UNITS. AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND OR ELECTRICITY

	Variable	Unit	Definition
Other Variables: Market Charac-tertic Variables (continued)	TIME		Time trend
Other Variables Climate	$JATEMP_t$	Degrees F	Mean January temperature, in the t^{th} period, in region α
	$JUTEMP_t$	Degrees F	Mean July temperature
	$DDAYS_t[\alpha]$		Degree Days
Elasticities	$\Sigma[s;P]$		Elasticity of demand with respect to average price for customers on rate schedule s
	$\epsilon[s,\alpha;P]$		Elasticity of demand with respect to average price for customers on rate schedule s in region α (relevant where the specification includes shift variables distinguishing states)
	$\Sigma[s;Y]$		Elasticity of demand with respect to income for customers on rate schedule s
	$\Sigma[s,\alpha;Y]$		Elasticity of demand with respect to income for customers on rate schedule s in region α (relevant where the specification includes shift variables distinguishing states)

Table 2 (continued). VARIABLES, UNITS, AND NOTATIONS EMPLOYED IN ECONOMETRIC STUDIES OF THE RESIDENTIAL DEMAND FOR ELECTRICITY

	Variable	Unit	Definition
Elasticities (continued)	$\varepsilon[s;NG]$		Cross elasticity of electricity demand with respect to (average) price of natural gas for customers on (electricity)
	$\varepsilon[s,\alpha;NG]$		Cross elasticity of electricity demand with respect to (average) price of natural gas for customers in region α on rate schedule s
	λ		Lag parameter linking short run and long run elasticities

Table 3. SELECTED REGRESSION RESULTS, RESIDENTIAL DEMAND EQUATIONS

HALVORSEN

$$\ell n\left(\frac{KWH_t[s;\alpha]}{B_t[s;\alpha]}\right) = -1.238 - 1.138\ \ell nREREV_t[s;\alpha]$$

$$+ .0355\ \ell nRENG_t[s;\alpha] + .6113\ \ell nMFY_t[\alpha]$$

$$- .3474\ \ell nPCTURB_t[\alpha] = .9245\ \ell nJUTEMP_t[\alpha]$$

$$- .0151\ \ell nTIME(t)$$

$$R^2 = .9031$$

WILSON

$$\ell n\left(\frac{KWH_t[s;\alpha]}{HH_t[s;\alpha]}\right) = 10.25 - 1.33\ \ell nFPC500_t[s;\alpha]$$

$$+ .31\ \ell nNOMNG_t[s;\alpha] - .46\ \ell nMFY_t[\alpha]$$

$$+ .49\ \ell nR/HSE_t[\alpha] - .04\ \ell nDDAYS_t[\alpha]$$

$$R^2 = .566$$

most consumption goods, of equality between marginal and average price. Which "price" is appropriate for the specification of an econometric model of electricity demand?

(b) The appropriate approximation to the universe of all other goods: obviously all other goods cannot be considered, and so it is necessary to limit the goods considered to all other relevant goods, good: which are either close complements of or close substitutes for electricity. This in turn devolves into the examination of the disaggregated components of residential consumption.

We turn to a discussion of these and related difficulties.

The Relevant Price Variable

Which price is appropriate to the specification of an econometric model of residential electricity demand? The obvious answer is: whatever price consumers respond to in making consumption decisions. In asking what that price is, we must be mindful that information is costly--that time spent in the careful examination of a rate schedule has an opportunity cost. Casual empiricism suggests that few residential consumers know the difference between the steps of their rate schedules, and it has been suggested that utilities be compelled to mail a copy of their rate schedules to residential customers at least once annually, as some phone companies are required to do. The situation is unlikely to change with the advent of electricity-intensive housing styles, since--as the evidence we shall review below makes clear--residential electricity demand is income inelastic and thus comes to occupy a smaller portion of the family budget, while higher real incomes increase the opportunity cost of time spent in making consumption decisions.

Average real residential price thus appears to be the appropriate price variable in the specification of the residential demand for electricity. This is the variable that has been used in most econometric studies of residential demand, so that we can simply take over those estimates. Further, there is a simple relationship between average and marginal price elasticities of demand for a commodity sold at a quantity discount, so that we can construct an estimate of marginal price elasticity from an estimate of average price elasticity A quantity discount relationship can be approximated by

$$ar(q) = \bar{p}\, q^{\beta} \qquad -1<\beta<0, \qquad ($$

where q is KWH purchased per month, ar average revenue, and $\bar{p}$ and β are constants. Then the relationship between average and marginal expenditure is derived as follows: equating two necessarily equal expressions for total expenditure gives

$$q\ ar(q) = \int_0^q (dq)mr(q) \qquad ($$

where mr is marginal revenue. Substituting the above relationship for average price as a function of quantity, we are left with

$$\bar{p}\ q^{(1+\beta)} = \int_0^q (dq)mr(q) \qquad ($$

Differentiating with respect to q we have

$$(1+\beta)\bar{p}q^{\beta} = (1+\beta)ar(q) = mr(q) \qquad ($$

so that we may solve for marginal revenue in terms of average revenue, obtaining

$$ar(q) = \frac{mr(q)}{(1+\beta)} \tag{5}$$

Now suppose that we have estimated the coefficients in an average revenue demand equation by regressing the natural logarithm of average KWH consumption upon average residential revenue and other variables. Then the resulting coefficients in the equation

$$\ell n\ q_t[s;\alpha] = A + B\ell n\ \ ar_t[s;\alpha] + . . . \tag{6}$$

can be related to the estimates which must be appropriate to the marginal-price demand equation as follows. Since

$$\ell n\ ar(q) = \ell n\ mr(q) - \ell n(1+\beta) \tag{7}$$

substitution into the average price equation gives

$$\ell n\ q_t[s;\alpha] = \left(A - B\ell n(1+\beta)\right) + B\ \ell n\ mr(q_t) + \cdot \cdot \cdot \tag{8}$$

Thus, if -/B/ is the average price elasticity of residential electricity demand, the "corresponding" marginal price elasticity is -/B/: the two are equal.

<u>Which Other Goods Must be Included?</u>

Which goods are appropriately close complements and substitutes and therefore worthy of inclusion in the specification of the demand function? Consider the spectrum of residential uses of electricity: lighting, space heating, space cooling, and water heating. With the exception of lighting, there are non-electric alternatives for the other functional requirements, e.g., gas and oil for space and water heating. But the substitution of gas for electricity requires costly conversion of consumer durable equipment. Residential demand for electricity and fuels is ultimately demand for service flows produced by use of fuels and electricity in conjunction with "appliances" or "white goods" (broadly defined so as to include lighting fixtures). This complementarity is the novelty in the problem of electricity demand estimation, an is ultimately responsible for the discrepancies between earlier and later elasticity estimates. Consider the complications introduced into the usual conceptual distinction between short run and long run demand elasticities. The short run that period in which consumer-owner capital, or appliance stocks, cannot be varied in response to demand, so that sho run changes in demand in response to price changes are whole attributable to variations in the intensity of use of fixed stocks of appliances. The relevant "other goods" for an estimate of short run demand elasticity are, therefore, severely limited: appliance stocks definitionally are fixed, and fu electricity substitutions cannot proceed without changes in appliance stocks. The appropriate specification of short r residential electricity demand would seemingly include only electricity price, and perhaps income, as independent variables

The long run is that period in which capital stocks of consumer durables are subject to adjustment in response to related price changes. A cost minimizing consumer would, in long run adjustment, be producing the desired bundle of service flows with least cost fuel-appliance combinations. An appropriate specification of independent variables for the long run demand for electricity would, therefore, necessarily include measures of relative appliance prices, or, more specifically, the annual price of capital services for various appliance types.

Short Run Versus Long Run Elasticities

In which elasticities are we interested, short run or long run? Our interest is in the probable response of demand patterns to changes in rate levels and structures, and in valuation of the associated benefits. Short run elasticities are, therefore, appropriate to the question of attainable benefits within a period where consumers cannot alter appliance stocks and utilities cannot alter their capital structure and the requirement of meeting the fixed costs of that capital structure. Long run elasticities are relevant to the evaluation of benefits attainable over the "period" in which both producer and consumer capital structures can be adjusted. They are the benefits foregone by inappropriate pricing policies.

Cross Section, Time Series and Pooled Models: Which Elasticities do They Measure?

Demand studies have been done in cross section, in time series, and with pooled time series and cross section data. Cross sectional studies employ data from a given year, with the various data points corresponding to different locations; time series data build upon the observations, for several years, of data from one location, and pooling of time series and cross section data is just what the name implies. Time series data from many locations are thrown together to give a larger sample than either pure time series or pure cross section data alone could provide and, hopefully, improved estimates of model parameters. Table 1 indicates that only John Wilson's 1971 paper does an estimate in pure cross section, which lends a special significance to the results of this paper. All other reported results are based upon pooled time series and cross section data bases.

To begin, then, with the pure cross section case, the elasticity estimates derived from such a study are properly to be considered long run. For there is great heterogeneity of cost conditions, among the contiguous states, and state data for any given year presumably reflect the adjustment to local conditions which consumers have made over time. Since state cost differences are persistent--due to factors such as the presence or absence of cheap hydroelectric and/or public power--cross section coefficients are, therefore, reasonably interpreted as based upon data on consumers in long run equilibrium. The regional variation in cost is, as we shall see, fortunate, for it enables us to get a significant estimate of the price coefficient.

What of estimates based upon pooled data? Clearly there is the possibility of interpretations of such data which conflicts with the interpretation of cross section results offered above Each year's data cannot reflect the long term adjustment of consumption to price and other determinants, for clearly the must be some adjustment of consumption to changes in short r determinants--prices and incomes--in a time span smaller than that in which complementary consumer durables (stocks and appliances) can be adjusted. In a reasonably long time series of cross sections--say ten years, a period in which the stock of consumer durables is considerably changed by replacement and additions--both will be present, with short run adjustment of consumption to changes in price and income accompanied by long run adjustment of consumer durable stocks. The pressing problem in the interpretation of the results of cross section studies is therefore the disentanglement of short and long term effects. This, in general, requires that some specific assumption regarding the mechanism by which consumers adjust to disequilibrating changes in independent variables be specified. However unpalatable and oversimplified the specific models employed seem, it is of some comfort that the form of the lagged response assumed usually has little effect upon the relevant parameter estimates. Once a specific adjustment structure is assumed, short run and long run estimates are functionally related.

Having thus enumerated the problems that beset all of the efforts to date at econometric estimation, we turn to a discussion of the individual estimates of the residential demand for electricity. Industrial demand estimates are often very different methodologically, and are therefore treated separately later.

RESIDENTIAL DEMAND ESTIMATES

Fisher and Kaysen[5]

This study merits attention greater than that usually accorded an econometric study more than ten years old, and for a very simple reason: as a first and an exhaustive study of the demand for electric power , it set the agenda for almost all subsequent work in the field. Indeed, most of the improvements of later papers --and we believe these have been substantial--are to be found as throwaways in the Fisher-Kaysen book, suggested but never pursued.

The hallmark of the Fisher-Kaysen approach is the recognition, at every turn, that residential electricity is used in the home in conjunction with consumer durables--"white goods," or appliances, with the definition of appliances stretched to include lighting fixtures--in order to produce desired service flows. All behavioral models exploit this dependence in the specification of the demand for electricity.

Fisher-Kaysen start from the behavioral hypothesis that, in the short run, price and income are determinants of the level of utilization of the existing stock of white goods, so that demand may be written

$$KWH_t[s:\alpha] = C\left[REREV_t[s;\alpha]\right]^{\varepsilon[s;p]} \left[DPIPC_t[\alpha]\right]^{\varepsilon[s;y]} \sum_i W_{it}[\alpha] \qquad (9$$

where we have transcribed the notation used in Fisher-Kaysen into the unified notation introduced in Table 2; additional variables required here are $W_{it}[\alpha]$, the average stock of the $i^{\underline{th}}$ white good possessed by the community during time period t. The "price" variable is what purports to be a real price variable, i.e., nominal average revenue deflated by the con. sumer price index.

This is not the equation estimated by Fisher and Kaysen; the first take (natural) logarithms, obtaining

$$\ell nKWH_t[s;\alpha] = C' + \varepsilon[s;p] \;\; \ell nREREV_t[s;\alpha] + \varepsilon[s;y] \; \ell nDPIPC_t[\alpha] + \ell n \sum_i (W_{it}[\alpha]) \qquad (1$$

and then take first differences, which gives

$$\ell nKWH_t[s;\alpha] - \ell nKWH_{t-1}[s;\alpha] = C'' + \varepsilon[s;p](\ell nREREV_t[s;\alpha] - \ell nREREV_{t-1}[s;\alpha]) + \varepsilon[s;y](\ell nDPIPC_t[\alpha] - \ell nDPIPC_{t-1}[\alpha]) + \text{white goods term} \tag{11}$$

Assuming that changes in the stock of white goods follow an exponential growth path at a constant growth rate, first-differencing "eliminates" the time dependence in the white goods term, since

$$\ell n(W_o \ell^{rt}) - \ell n(W_o \ell^{r(t-1)}) = +r. \tag{12}$$

from (11) and (12) we have

$$\frac{KWH_t[s;\alpha]}{KWH_{t-1}[s;\alpha]} = C''' \left(\frac{REREV_t[s;\alpha]}{REREV_{t-1}[s;\alpha]}\right)^{\varepsilon[s;p]} \left(\frac{DPIPC_t[\alpha]}{DPIPC_{t-1}[\alpha]}\right)^{\varepsilon[s;y]} \tag{13}$$

Note that this equation could almost have been written down from scratch: it is a variant of the simplest model of short run demand adjustment, with demand dependent upon own-price and income. The growth of white goods is thus subsumed into the constant term of the model of the above equation.

The short run elasticity estimates are thus estimates of a fluctuation, assumed due to short run fluctuations in prices and income, about a trend. The growth trend is deemed exogenous. The problem of disentangling long run and short run elasticities is therefore "solved" in this case by assumption for price and income are not determinants of the long run de-

demand for electricity. That long run trend is determined solely by exogenous growth. This procedure makes us wary of the Fisher-Kaysen short run estimates.

The situation is even more serious for the Fisher-Kaysen long run elasticity estimates. Given the commitment of these authors to the use of white good stock data--as opposed to some indirect measure of consumer durable stock decisions, such a appliance prices--the validity of the final estimate will depend critically upon the quality of the stock data. It is therefore unfortunate that the time series data on white goods stocks employed in the Fisher-Kaysen study is questionable. This much they recognize. Worse, further examination of their stock data indicates that it seems to be wrong in just such a manner as to bias the price elasticity estimate downwards: that is, appliance stocks in states in which electricity is expensive seem to be overestimated, and appliance stocks in states in which electricity is cheap seem to be underestimated. For this reason it would seem unadvisable to use Fisher-Kaysen elasticities in our subsequent work.

Chapman et. al.[3]

This recent addition to the literature, presented at the February 1973 NSF-MIT conference and available in preliminary form from Oak Ridge National Laboratory, has one notable advantage of conceptual simplicity: the simplicity of the dynamic specification leads to a transparent and appealing relationship between short and long run demand elasticity estimates. The price paid for that simplicity is the somewhat obscured relationship between the model specification and behavioral assumptions. The Chapman et. al. specification is

$$KWH_t[s;\alpha] = (KWH_{t-1}[s;\alpha])^{\lambda}[t^{th} \text{period factors}] \tag{14}$$

where only the time dependence of the multiplicative factors, and not their precise interpretation, are relevant. Suppose that there is only one multiplicative factor specified in the form $(F(t))^{\varepsilon[s;F]}$. Then in logarithms

$$\ell nKWH_t[s;\alpha] = \lambda \ell nKWH_{t-1}[s;\alpha] + \varepsilon[s;F]\ \ell nF(t) \tag{15}$$

Suppose that in the first period there is a once and for all (exogenous) increase in the factor F; serviceable examples include an increase in the price of a substitute fuel or an increase in the price of complementary goods, e.g., appliances. Then the specification above tells us that the corresponding first-period fractional change in consumption is

$$\frac{\partial \ell nKWH_1[s;\alpha]}{\partial \ell nF(1)} = \varepsilon[s;F]. \tag{16}$$

But this is the beginning and not the end of the story, since the sequential adjustment specification leads to changes in all future periods. Thus second-period consumption is determined by the two equations

$$\ell nKWH_1[s;\alpha] = \lambda \ell nKWH_0[s;\alpha] + \varepsilon[s;F]\ell nF(y) \tag{17}$$

$$\ell nKWH_2[s;\alpha] = \lambda \ell nKWH_1[s;\alpha] + \varepsilon[s;F]\ell nF(y) \tag{18}$$

so that the percentage change in second-period consumption arising from a small change in F(1) is, after using the first equation to eliminate $\ell nKWH_1[s;\alpha]$ from the second and then differentiating,

$$\frac{\partial \ln KWH_2[s;\alpha]}{\partial \ln F(y)} = (1 + \lambda)\varepsilon[s;F] \tag{19}$$

In general, the percentage change in $n^{\underline{th}}$ period consumption is

$$\frac{\partial \ln KWH_{12}[s;\alpha]}{\partial \ln F(y)} = (1 + \lambda + \lambda^2 + \ldots + \lambda^{n-1})\varepsilon[s;F]$$

$$= \frac{1 - \lambda^n}{1 - \lambda}\varepsilon[s;F] \tag{20}$$

if $0 < \lambda < 1$. The ultimate consumption change--the change a n is taken to be very large--is thus

$$\lim_{n\to\infty} \frac{\partial \ln KWH_n[s;\alpha]}{\partial \ln F(y)} = \frac{1}{1 - \lambda}\,\varepsilon[s;F] \tag{21}$$

The conventional interpretation of the parameters--or, more precisely, of econometric estimates of these parameters--is as follows. $\varepsilon[s,f]$ is taken to be the short run elasticity of electricity consumption with respect to determinant F, an $\frac{1}{1 - \lambda}\,\varepsilon[s;F]$ the long run elasticity of electricity consumption with respect to this same determinant. If annual data is used in the estimation--and all time series estimates wit which we are familiar use annual data--the "short run" of reference is the year. The long run is, strictly speaking, infinity. The fraction of adjustment completed after n periods is, as computed above,

$$\frac{1 + \lambda + \ldots + \lambda^{n-1}}{\frac{1}{1 - \lambda}} = (1 - \lambda)(1 + \lambda + \ldots + \lambda^{n-1})$$

$$= (1 - \lambda)\left(\frac{1 - \lambda^n}{1 - \lambda}\right) = 1 - \lambda^n \tag{22}$$

Thus, for λ close to zero, adjustment is rapid, and for λ close to 1, adjustment of consumption to long run equilibrium values is slow: for $\lambda = .1$, consumption has reached .99 of its long run equilibrium value after five years, whereas for $\lambda = .8$, consumption has reached only .33 of its long run equilibrium value after five years. As we shall see, the estimates of λ are all approximately .9, indicating a protracted period of adjustment.

Because of the plausibility and conceptual appeal of the Chapman et. al. dynamic specification--and the specificity, to individual states, of their price elasticity estimates--their long run elasticity estimates are the ones we have used in our later numerical evaluations of pricing improvement indicators. We have compiled the Chapman et. al. estimates in Table 4.

Table 4. RESIDENTIAL ELASTICITY ESTIMATES, Chapman et. al.

System	State	Long Run (Average) Price Elasticity of Demand
Potomac Electric Power Company	District of Columbia and Maryland	-1.22
Commonwealth Edison Company	Illinois	-1.22
Duke Power Company	North Carolina	-1.18
New York State Electric and Gas	New York	-1.24
Pennsylvania Power and Light	Pennsylvania	-1.22

These are the numbers which we actually use; accordingly, our remaining discussion of residential demand estimates focuses principally upon their conceptual innovations, with little attention to the numerical estimates they actually yield.

Wilson[8]

John Wilson's 1971 paper differs from almost all of the other econometric demand estimates, and in several important dimensions. The data base is purely cross sectional, so that the is not question of distinguishing short run and long run adjustment of consumers to local conditions; the regression analysis ideally can isolate the long run effect of each of the variables upon consumption. How, we may ask, does this square with the underlying reality assumed in the estimation of the Chapman et. al. models? Or, put another way, what comparability is there between a "long run" elasticity estimate in pure cross section and the "long run" elasticity estimate from a pooled sample of time series and cross sections with specific dynamic adjustment mechanism assumed? In general, the question is quite complex. Here, it may help to think along the following lines for specific equations which we wish to compare. 'The pure cross section and time series studies might be contrasted as based, respectively, on the following data:

	Variables: Dependent	Variables: Independent	Data Base
Pure Cross Sectional	$\ell nQ_{t_o}[\alpha]$	$\ell nF[t_o;\alpha]$	$\alpha = 1, 2, .$
Pooled	$\ell nQ_t[\alpha]$	$\ell nQ_{t-1}[\alpha]$,	$t = 1, 2, .$
		$\ell nF[t;\alpha]$	$\alpha = 1, 2,$

Compare the equations to be estimated.

Pure Cross Sectional	$\ell nQ_{t_o}[\alpha] = C + \gamma\ \ell nF[t_o;\alpha] + \ldots$	$\alpha = 1, 2, \ldots$
Pooled	$\ell nQ_t[\alpha] = \delta + \lambda \ell nQ_{t-1}[\alpha] + \omega \ell nF[t;\alpha]\ldots$	

The comparison indicates that, if we consider only the $t = t_c$ cross section from the pooled sample, then the lagged term, its coefficient and the constant term collapse into one overall constant. Estimation of this cross section alone is completely equivalent to estimation of the pure cross section model. What then is the relationship--in magnitude and reliability--between estimates of the all-important elasticity parameters in the two models? Suppose, for the sake of exposition, that the general "causal factor" $F(t;\alpha)$ is taken to be the average real price of electricity. Then the difference between the parameter estimates γ and $\frac{\omega}{1-\lambda}$, the respective "long run" elasticity measures, depends upon the correlations between the lagged consumption variable and the price variable., Since consumption has grown almost exponentially over the postwar period, while average real price has, depending upon the measure used, either declined or remained constant, the correlation between lagged consumption and average price variables is probably extremely small. We therefore might anticipate that price elasticity estimates--γ and $\frac{\omega}{1-\lambda}$ --should be of comparable magnitude. However, we know there are strong correlations between income and consumption measures over the relevant period, so that cross sectional and pooled estimates of comparable income elasticity parameters might be expected to differ substantially.

TO be somewhat more precise about comparability; if consumption were dominated by trend growth at rate r, then the comparable long run elasticity parameters would be

$$\gamma \quad \text{and} \quad \frac{\omega}{1 - \frac{\lambda}{1 + r}} .$$

Note that the latter differs from the Chapman et. al. "long run elasticity" in that $\left(1 - \frac{\lambda}{1 + r}\right)$, rather than $(1 - \lambda)$, alone appears in the denominator. In the section in which we discuss the empirical estimates obtained by the various investigators, we shall see that these comments are fairly well borne out. For present purposes, an idea of the numerical magnitudes may help. Were $\omega = .2$, $\lambda = .9$, and $r = .07$, all of which values are fairly realistic, then the expressio $\left(\frac{\omega}{1 - \frac{\lambda}{1 + r}}\right)$ equals 1.258, which is the value we might reasonably expect to emerge from a cross sectional study.

We must return, briefly, to the problem of the choice of price variable. For any direct comparisons of the Wilson and Chapman et. al. results must take account of the different price variables used in the two studies. Chapman et. al use average revenue, as do almost all other investigators. Wilson, in this as in many other respects the exception, use $FPC500_t(s;\alpha)$, the Federal Power Commission typical electrical bill for 500 KWH consumption in region α (i.e., state α). The typical electric bill is a widely-used construct, and worth a few definitional and critical comments. The typical electric bill for a given KWH quantity in a given state is for a given rate schedule--here, residential--constructed as follows.. From utilities serving the state in question the Federal Power Commission (FPC) obtains rate schedules. Next the FPC computes the bill, under each rate schedule, for a given consumption--in our case 500 KWH, which is the computed consumption closest to the national average residential consumption for the year studied by Wilson. (Incidentally, that year is never directly identified.) Since typically only one utility serves a given city, no further work is required. For cases where a city or a Standard Metropolitan Statistical Area (SMSA) is served by two or more utilities, the individual utility bills are weighted by the numbers of customers served to give an average typical bill. (Note that, since Wilson works in cross section, there is no need to worry about real versus nominal price specifications.)

Which price variable--average price or typical bill--is to be preferred, and why? The defects and virtues are distributed over both candidates. The use of statewide average revenues as a price variable undoubtedly, as Wilson suggests, blurs the often substantial variation of average revenue within a state. Using an example of Wilson's, the city of Buffalo in New York State, which benefits from cheap Saint Lawrence River hydropower, is averaged with relatively expensive New York City power. Market and State boundaries simply do not coincide. Furthermore, the use of the typical electric bill provides a natural means of circumventing the difficulty of estimation imposed by the declining block rate schedule. For if the estimation is to be a single-equation estimate, then how can we face up to the fact that quantity taken our dependent variable in Wilson's first model, is in fact simultaneously determined with "price" because of the declining block schedule? Technically, the problem is that of the identification problem of econometrics. In words the difficulty is that, if we seek information on the relationship between price and quantity taken from data reflecting consumer purchases under declining block rate schedules--i.e., with true quantity discounts--then we cannot be certain of the interpretation of our result. In some measure it will reflect the negative relation, arising from the rate schedule alone, between quantity taken and unit price; in some measure it will also reflect the inverse relationship between quantity taken and effective price, basic to demand theory. Wilson's use of the typical electric bill for a given level of consumption as the price variable is one way around the difficulty, but its rationale is not easy to state precisely For KWH consumption per household is the independent variable in the Wilson paper (cf. Table 3), so that higher and lower per household consumption levels have been washed out, and a. are being explained by a "price" variable which corresponds, and only approximately, to the total bill for a KWH total (500) approximating average consumption. The possibility of attributing too much explanatory power to the "price" variable (i.e., of biasing upwards estimates of "price" elasticity of demand) thus arises as follows. Since utilities typically cover average costs of service for customer classes, there may be considerable variation in the block height assigned any one block. If for some reason there was a systematic downward bias of the average consumption block in low consumption areas, and a similar upward bias of the average consumption block upwards in high consumption areas, the resulting price elasticity estimate would be too high. There is, however, little reason to expect such systematic effects.

Halvorsen[6]

The wrinkle in this paper is the effort to improve upon previous estimates by explicitly modeling both demand and supply sides of the market. The supply side is specified by an equation in which average nominal supply price is explained as a function of variables which may be classified as factor cost variables, market structure variables, and a time trend variable. Since this is a supply equation and not a demand equation, it is the only residential-market equation in the papers discussed in this chapter which is not enetered in Table 3; we therefore enter it here, with all variables as defined in Table 2:

$$NOMREV_t(s;\alpha) = F(\frac{KWH_t(s;\alpha)}{B_t[s;\alpha]}, PCTPVT_t(\alpha), R/IS_t(\alpha), PCTURB_t(\alpha); FUELSG_t(\alpha), MHEMFG_t(\alpha); TIME(t)) \quad (24$$

The dependent variable is the average nominal revenue earned in residential sales. Demand is taken to be a function of real price, so that deflation is necessary in order to link demand and supply parts of the Halvorsen model. Since Halvorsen chooses to deflate by the Consumer Price Index, the relevant linking equation is

$$NOMREV_t = REREV_{t/CPI_t} \quad (25)$$

Use of the Consumer Price Index as a deflator is common to several papers, notably Chapman et. al. and Halvorsen, and we comment below on the implications of this procedure. Returning to the Halvorsen supply equation, the factor cost variables are (1) the average price of fuel used in steam generation variable $FUELSG_t(\alpha)$--see Table 2 for the exact definition--and (2) a labor cost variable $MHEMFG_t$. However, it is capital costs that bulk largest in the cost structure of the electric power industry, as we will see, and clearly these costs must be important in explaining supply price. Where, then, are these costs in Halvorsen's supply equation? He suggests that the major determinant of capital cost is "public versus private ownership," so that the variable $PCTPVT_t$, the percent of total electric utility generation generated by investor-owned utilities in the state in question in year t, is in effect a capital cost variable. But not the only one, for a major component of the cost of residential service is the distribution cost, which is almost pur capital cost. Distribution costs are in turn determined by the density of customers and the intensity of use by those customers. To the latter factors correspond the variables $PCTURB_t$ and KWH_t/B_t respectively, the percent of the given state's population in urban areas and KWH sales per customer. Thus the all important capital cost determinants of the supply schedule facing the individual residential customers are spread over three independent variables. The sole remaining market structural variable $R/IS_t(\alpha)$, the ratio of total residential to total industrial sales, is included as a measure of possible cross subsidization of the residential market by the industrial market. For why, were there no such cross subsidization, should the supply price of electricity to the residential consumer depend upon the relative market shares of residential and industrial customers'? Note that the variable in question is a ratio, and thus scale effects cannot be relevant. Clearly a larger overall market allows the exploitation of economies of scale, so that both residential and industrial supply prices may be lower than otherwise, but--with one small quibble--there should be no dependence or average supply price on the composition of the market. The quibble is as follows. If residential sales are more sharply peaked than industrial loads--this is typically the case--then markets of equal total consumption will be higher cost the higher the fraction of residential sales in total sales, since capacity requirements are correspondingly higher. This argument would lead us to expect a positive coefficient for the $R/IS_t(\alpha)$ variable; the cross-subsidization argument, in the form that residential customers, being more numerous and correspondingly more vocal than large power customers, are likely to get a subsidy from industrial customers, indicates that a negative coefficient for this variable is probable. Since that latter expectation is borne out in the estimates, the first, contrary argument may be dismissed. Halvorsen's specification of a supply side--remember this is not "industry" supply, whatever that might mean in the case of electric power, but the supply schedule faced by the individual consumer--is his means of circumventing the problems raised by the declining block schedule. Note the difference between his and Wilson's approach: Wilson chooses as price variable the typical bill for 500 KWH, hopefully a quantity independent measure of price within a small quantity range. Halvorsen, on behavioral grounds, uses an average price variable, with supply to the individual customer then considered perfectly elastic at that price, so that the various data points given by the time series of cross sections used in the estimates trace out the demand curve. Wilson's assumption can be re-expressed as follows: if most consumption occurs in a relatively narrow band around residential consumption, then the cross section used in estimation sketches out the movement of the particular block in which 500 KWH sits along the demand curve; if customers are responsive to marginal price, this traces out a small portion of the demand curve, providing an estimate of that curve. The resulting estimate is, of course, not clearly a marginal price elasticity or an average price elasticity, since different data points differ in both marginal price and average price: an easy way to think about the different cross section data points is as originating from the motion of the intersection of the marginal price graph and the demand curve as the former is moved vertically.

INDUSTRIAL DEMAND ESTIMATES

We know less about industrial and commercial demand than about residential demand. The reasons center upon the different pricing schemes employed for the different rate schedules. Residential electricity is invariably priced at some block rate, with block heights and lengths independent of particular characteristics of the customer's load. But commercial and industrial schedules characteristically are "demand billed," i.e. the customer's bill depends upon both energy consumption and load characteristics, and upon the latter in a way that can become quite complex. Consequently the use of an average revenue figure as a price variable distorts the actual operation of the rate structure even more seriously than in the residential case. We know of no study, wherein this problem is faced even somewhat squarely. What is known, is summarized briefly below. Brevity is dictated not by the intrinsic unimportance of the subject--certainly an allocation of time between residential and commercial and industrial markets on the basis of any measure of intrinsic importance would heavily favor the latter two categories--but by the circumstance that, although the data base for estimating and, of course, the resultant estimates are different, the methods either yield little or are suspiciously similar to those developed for the estimation of residential demand.

Roughly speaking, there are two sorts of estimates of industrial demand: those based upon specific industry data, and those based upon data on sales to customers served under industrial rate schedules in the individual states. The original industrial demand estimates of Fisher and Kaysen and the subsequent work of Baxter and Rees and of Anderson are in the first category, whereas the industrial estimates presented by Chapman et. al. are in the second category. For reasons to be discussed below, the applicability of the Baxter and Rees and the Anderson papers to a discussion of electricity alone is questionable. The remaining menu of industrial demand studies is limited, and it is to a comparison of those approaching that we turn. After the completion of that general comparison, we return to the individual papers and finally to their numerical estimates.

Industrial Demand Estimates: Some General Comments

Very crudely, what is likely to be the difference between econometric estimates of industrial electricity demand based upon aggregative industry data and estimates based upon stat industrial rate schedule data? In the first category, for example, we might have electricity consumption by two-digit Standard Industrial Classification industry group, and value of purchased electricity at that same level of aggregation. (Self-generated electricity can, and typically is, adjusted for in these studies by valuing such an input as the firm "should," i.e., at the market average revenue "price" for electricity. The adjustment is added to purchased electric power to give a market value of electricity used, and it is this latter market value that enters the industry demand studies.) Thus there is considerable aggregation over physical outputs, since the two-digit industry groups are already aggregates of firms producing closely-related products. Further, there may be considerable geographic aggregation since, for example, a two-digit manufacturing industry may subtend establishments spread over the entire country. What of the other kind of industrial demand estimate? If we use state data on sales under industrial rates schedules, then we disaggregate in one dimension while further aggregating in another: the aggregation over products includes everything produced by firms purchasing electricity under industrial rates schedules, while spatial aggregation is restricted to areas no larger than the largest state.

To put the matter in this way virtually dictates our choice Of elasticity estimate. Our work is to be based upon the study of individual utility costs and rates, and the customer classes we study will be the customer classes served by individual utilities under individual rate schedules. Ideally, we should like to have elasticity estimates specific to those individual rate schedules of individual systems. As a second best choice, estimates based upon sales by rates schedule and by state will probably not be too bad, since an individual utility service area is often a good part of a state, and there is at least some hope that industry mix is not too nonhomogeneous across one state. Thus, we must work with the state-based estimates. To work in the other direction--from industry-specific estimates through some estimate of industry mix in individual service areas to an imputed elasticity for a specific utility service area--would be close to impossible. Nevertheless, it is instructive to look at the magnitudes of elasticity estimates obtained on the two types of studies, and for this purpose we discuss the Fisher and Kaysen estimates. The estimates we actually use in our later work are those of Chapman et. al. and are made in the same way as the residential demand estimates given by those authors, so that our above discussion of their method of estimation need not be repeated.

Fisher and Kaysen[5]

The industrial demand estimates of Fisher and Kaysen are a relatively small portion of their book. As in the case on their residential demand estimates, there is an extensive and not entirely persuasive effort, based upon the theory of derived demand, to justify the final specification. We content ourselves, as Fisher and Kaysen might have done, with the following observation, which automatically yields the function form they finally estimate. For industry j, suppose that output $Y_j(t)$ in period t is produced with electricity in

Put E_j (t) and other inputs $X_k(j,t)$, k = 1, ...m. Then if all firms in the industry are identical in size and production technology, and the technology is Cobb-Douglas, the industry production function can be written as

$$Y_j(t) = (\text{Constant})x(E_j(t))^{\alpha(E)} \quad (X_k(j,t))^{\alpha_k}$$

If the price of electricity to the industry in period t is $p_j^E(t)$, and the price of each other input in that period $p_j^k($
then the Cobb-Douglas production function has the pleasant property of giving inverse demand functions which are themselves products of powers of (industry) output and input prices:

$$D_j^E(t) = (\text{Constant})x(Y_j(t))^{\beta}(P_j^E(t))^{\alpha} \text{ (Prices of other inputs to different powers.)}$$

Because Fisher and Kaysen have no information on other inputs they drop all other factors, and proceed with estimation on the assumption that industry electricity demand may be represented as the product of industry output to some power and the price of electricity to some other power, a sort of truncated Cobb-Douglas derived input demand function:

$$D_J^E(t) \approx (\text{Constant})X(Y_j(t))^{\beta}(P_j^E(t))^{\alpha}.$$

This is the equation Fisher and Kaysen estimate. The data base for estimation, as indicated in Table 1, is derived from Census of Manufactures 1956 data for selected states. Since the number of such states differ across two-digit industries, the degrees of freedom for each industry estimate (See Table 5 Industry Regressions: Two-Digit Industries, 1956, reproduced from Fisher and Kaysen) differ between states.

Table 5. INDUSTRY REGRESSIONS: TWO-DIGIT INDUSTRIES, 1956

Industry	α	β	K	R^2	Degrees of Freedom	β Significantly Different from Unity
20 Food and Kindred Products	—0.7841 (0.4065)	+0.6591[aaa] (0.1324)	12.88	.8323[aaa]	11	YES
22 Textile Mill Products	—1.6167[aaa] (0.1117)	+1.0071[aaa] (0.0877)	2.84	.9880[aaa]	6	NO
26 Pulp, Paper, and Products	—0.9747[a] (0.2077)	+0.7203 (0.4205)	26.43	.8822[a]	3	NO
28 Chemicals and Products	—2.5976[aaa] (0.5234)	+0.6150[a] (0.2167)	22.55	.6387[aaa]	14	NO
32 Stone, Clay, and Glass Products	—1.7386 (1.2231)	+1.0273[a] (0.3074)	2.44	.8429	3	NO
33 Primary Metal Industries	—1.2829[aaa] (0.2117)	+0.4937[aaa] (0.1188)	9.17	.7428[aaa]	16	YES
34 Fabricated Metal Products	+0.5533 (0.4832)	+1.1094[aaa] (0.1143)	0.29	.9593[aaa]	4	NO
	—	+1.1009[aaa] (0.1175)	0.39	.9460[aaa]	5	NO
35 Machinery, Except Electrical	—1.3349[a] (0.4286)	+0.9043[aaa] (0.0870)	1.30	.9742[aaa]	7	NO
36 Electrical Machinery	—1.8209[a] (0.4489)	+0.3797 (0.2191)	76.50	.8985[a]	4	YES
37 Transportation Equipment	+0.6877 (0.6445)	+1.0526[aaa] (0.1174)	0.61	.9521[aaa]	5	NO
	—	+0.9859[aaa] (0.1005)	1.04	.9412[aaa]	6	NO

[a] Significant at five per cent level.
[aa] Significant at one per cent level.
[aaa] Significant at one-tenth of one per cent level.

Reproduced from Fisher and Kaysen

Chapman et. al.[3]

We have discussed the method employed in this paper above; in Table 6 we compile the actual estimates from this paper which we use in later calculations. Remember that, although Fisher and Kaysen do not discuss the commercial sector--and for obvious reasons, since there is no data for the commercial sector which would mesh with their estimation methods--any unified estimation. method constructed so as to mesh with state data, such as the Chapman et. al. method, can distinguish a separate commercial sector. Therefore we employ this additional level of detail in our later calculations, and in Table 6 we compile the estimates for the states in which systems in our sample are located.

This completes our discussion of our selection of demand elasticities, which enter parametrically into our later indicator estimates. We turn to the cost side of our problem.

Table 6. COMMERCIAL AND INDUSTRIAL ELASTICITY ESTIMATES
Chapman et. al.

System	State	Long Run (Average) Price Elasticity of Demand	
		Commercial	Industrial
Potomac Electric Power Company	District of Columbia and Maryland	-1.46	-1.93
Commonwealth Edison Company	Illinois	-1.48	-1.87
Duke Power Company	North Carolina	-1.13	-1.65
New York State Electric and Gas	New York	-1.65	-1.89
Pennsylvania Power and Light	Pennsylvania	-1.46	-1.93

SECTION III

SOME RELEVANT FEATURES OF THE INTERNAL COST STRUCTURE OF THE ELECTRIC POWER INDUSTRY

A cost-of-service study for an individual utility is likely to be a one or two year or longer effort, often involving much of the staff of the rate division. The number of questions that can be raised is boundless. But by careful selection of the portion of the cost structure to be explored, we can guarantee that our analysis of the cost structure is exactly as detailed, and no more so, than required by our objectives. We therefore begin this chapter with the introduction of a framework for classifying and identifying those dimensions of cost structure which we must quantify. In a sense, this discussion belongs in the discussion of rates i Section IV; it has been located here because, without it, t selection of focus in the cost discussion must seem arbitra

A TYPOLOGY OF CUSTOMERS BASED UPON "INFORMATION" COSTS

Assume that every consumer reacts optimally to the options open to him. Then any consumer of electricity will find it efficient to allocate time to the electricity consumption decision to the point where marginal benefits of such time the reduction in electric bill, for given consumption, for the incremental minute spent in making the electricity consumption decision--just equal the incremental costs involve in this case the value of the incremental minute in its next most valuable use. The outcomes of this allocation decision process will be classified in two dimensions: time differentiating versus time-undifferentiating consumption decisions, and average price responsive versus marginal price responsive consumption decisions.

Table 7. A TYPOLOGY OF ELECTRICITY CUSTOMERS

	Time Undifferentiating	Time Differentiating
Average Price Responsive	I	II
Marginal Price Responsive	III	IV

Customers in Category I have found it optimal not to distinguish between average and marginal prices in their electricity consumption decisions. For these customers, the existence of block rates is irrelevant, for they would make the same consumption decision at a flat price equal to the average revenue they are currently paying. Customers in Category II by definition find it optimal to pay the cost of differentiating between their consumption on and off peak--either by paying the additional costs of metering peak and off peak consumption separately, or by taking a rate schedule option under which the company (nominally) bears the costs of such metering, or by accepting such devices as deferable load water heating. Note that, by definition, these customers have not found it optimal to distinguish between average and marginal price so that, once again, the question of block structure is of no relevance to them, for they would take exactly as much electricity at a flat average rate equal to their current average price as they take presently.

Customers in Category III by definition do not find it optimal to distinguish between peak and off peak consumption, but they have found it optimal to distinguish between marginal and average price. Finally, customers in Category IV have found it optimal to distinguish between consumption in both dimensions: between power taken off peak and at peak, and between average and marginal prices paid for electricity

So much for typology. The really important question is what if anything, belongs in the boxes: which customers wind up where? There are no unambiguous guidelines. First, it is not entirely clear that all customers on a given rate schedule belong in a single category. Large residential users, for example, may have some marginal price sensitivity and therefore belong in Category III, whereas very small residential users almost certainly belong in Category I.

Our identification of rate schedules with the categories of the above typology, and the corresponding benefit-cost calculations performed, are as follows.

Category

This category is the domain of small residential and commercial users. The relevant question regarding possible improvment in rate structures is then restricted by the assumption that consumers in this category do not, for information cost reasons, distinguish either marginal and average price or offpeak and peak consumption. That relevant question is in fact restricted to the question of inter customer-class adjustments in average price. How large are the efficiency gains to be expected from improved average pricing? Our methodology for the derivation of a quantitative measure of such available gains is based upon the work of Baumol and Bradford.

The method and results are spelled out in Section IV below. To the extent that the derived quantitative measures are reliable, they indicate that available gains are negligibly small.

Category II

Almost all rate schedules are potentially fair game for this category, and we will compute net benefit measures for all rate schedules of the sample companies as if it were the case that all rate schedules are average-price responsive--that they have found it optimal not to distinguish between peak and offpeak consumption. For residential customers presently metered on a KWH monthly or bimonthly basis, this will require netting of the additional cost of double-rate registers required to charge differential rates off peak and on peak. A warning regarding the full spectrum of benefits and costs for double rate register metering is in order: there is one potential serious drawback to double rate register metering of offpeak and peak hours. Should service to a given area be interrupted and restored in any time interval not a multiple of 24 hours, the correct setting of the doube rate register shall have been lost. It would be necessary to meter on a KWH basis, taking the simple sum of the offpeak and peak registers as the relevant number of KWH, until the time at which the meter was read, at that time the reader could reset the device. The evaluation of this problem is beyond the scope of this report.

Category III.

The prime candidates for Category III are large residential users if it is assumed that, for some reason, there is no possibility of differentiating between offpeak and peak usage for these customers. Again, recall our observation that all customers on a given rate schedule need not necessarily fall into the same category; for the return to an additional minute spent in a consumption decision is higher the higher the range of the contemplated purchase, so that it may pay a large residential user to become familiar with his or her rate schedule where it would not so profit a small residential user. Nevertheless, as we will see in our analysis of Category I, there is little to be gained from pricing changes which do not discriminate between offpeak and onpeak consumption. However, there is still the possibility of "implicitly" differentiating between offpeak and peak, and our major estimate corresponding to Category III is the estimation of an upper bound on the gains attainable from implicit differentiation. How might this work? Suppose that some system had a declining block rate schedule with only two blocks, with the tailblock lower than the first block. Suppose further that tailblock customers buy all their electricity on peak, while first block customers buy all their electricity off peak. 'Then we can in some measure simulate peak load pricing by raising the tailblock and lowering the first block. Advocates of "rate inversion" often argue for something like this, and we will calculate a rough upper bound on the welfare gains that implementation of one kind of rate inversion proposal will confer.

Category IV

Finally, in Category IV, we place our large commercial and industrial users. They incur little incremental expense in differentiating between their consumption off peak and on peak, since many utilities know and must know what the instantaneous load being pulled by their individual large customers is. Some of these customers also have that information. Similarly, there is little incremental expense to be incurred were such a large customer to "switch" from average price sensitivity to marginal price sensitivity, since so long as someone is watching the electric bill, the cost of watching it in a slightly different way is negligible. For these customers, a relevant benefit/cost question is: what is the magnitude of the gains likely to be had from time-differentiates pricing, e.g. a better matching of peak period (perceived) prices and costs? Some technical problems--the existence of demand-billing- -make this comparison awkward, but we shall see that it can be made, and that the attainable gains are probably substantial.

THE USES OF THE TYPOLOGY: A PRELIMINARY OVERVIEW OF INDICATORS TO BE ESTIMATED, AND COST ANALYSIS REQUIRED

Our purpose in constructing the above typology is the organization of our welfare gain calculations, and guidance of the cost analysis necessary for those calculations. In this section we spell out the first linkage. The discussion of cost structure, which completes the work of this section, follows.

It is simplest to proceed seriatim through the four categories of the typology. In each case the question is the same: wha welfare gain estimates are apposite to the corresponding typology category?

Category I

These are customers who find it impossible--extremely costly-to differentiate between peak and off peak consumption and similarly costly to distinguish between average and marginal prices. Where, under these constraining conditions, could improvement reasonably be sought? Only in adjustment of the relative average prices paid by the various customer classes. Suppose further that utility management chose to avoid the problems of offpeak versus peak period cost allocation for this class of customer, and attempted to follow naive second-best short run marginal cost pricing rules. (Discussed in detail below, and mentioned above, these rules suggest that prices be deviated from short run marginal cost in order to cover costs, with the deviations designed so as to minimize the resulting distortion of consumption patterns.) Then we can actually compute the welfare gains associated with such improved pricing. Obviously we will need for the purposes a reconstruction of short run marginal costs. That reconstruction will prove useful in introducing us to the difficulties inherent in utility cost data, and in the identification of marginal costs. The indicator associated with this calculation, call it indicator I, will be evaluated in Section IV.

Category II

These are customers assumed to differentiate between offpeak and peak usage, but not between average and marginal price. The relevant question is: how much is to be gained by charging differential flat average prices in offpeak and peak periods? We therefore cross into territory where a knowledge of the differential costs of providing electric service off peak and on peak is necessary. Consequently, we require an extensive discussion of peak versus offpeak cost structures The welfare gain calculation relevant to this customer category is, as suggested, efficiency gain available from a better matching of price and cost in offpeak and on peak period

Category III

These are customers who, because of their information cost structure, distinguish between marginal and average price but not between peak and offpeak periods; large residential users who cannot be metered in a way that distinguishes between time periods might reasonably be placed in this category. Then some leverage over their consumption pattern is available from changes in tailblock rates, i.e., from a form of what has come to be known as rate inversion. An upper bound to the efficiency gains from such inversion may then be estimated as follows: assume all tailblock consumption occurs during the peak, and assume marginal elasticities are relevant. BY a "tailblock customer" we mean a customer whose monthly consumption of electricity is sufficiently large to place him in the last block of the rate structure:. if, for example, all KWHs over 800KWH per month are billed at 1.0¢, then customers taking more than 800KWH during some month are in the tailblock for that month. Our assumption that all tailblock consumption occurs on peak simply means: we assume that all tailblock customers take all of their power during the peak hours of the day, and that their demand is constant during those hours. The welfare gain measure appropriate to this category, evaluated in Section IV, estimates the gains available from this form of inversion. This calculation obviously requires a knowledge of the differential costs of providing electricity off and on peak.

Category IV

Finally, what of those large commercial and industrial users who distinguish between average and marginal price, and between power taken offpeak and on peak? Here we can devise and evaluate a welfare measure of the gains associated with an improved fit between marginal price and peak cost. Because the typical user in this category is billed under both energy and demand schedules--the difference is explained below--formulation of the corresponding indicator is not as straightforward as in the previous cases. But the cost-structural information required for this evaluation is the same: an explicit identification of offpeak and peak costs.

We have completed a sketchy survey of the cost information we shall require, and we turn to the development of that information.

THE RECONSTRUCTION OF INTERNAL COST FUNCTIONS: SHORT RUN MARGINAL COSTS

Our objective in this subsection is a reconstruction of the short run marginal cost of serving each customer class, and an understanding of the limitations of the measure constructed. The incremental cost of service, at any particular time, is almost purely generating cost, the cost of the fuel required to generate an incremental KWH. There are usually larger line losses involved in "delivering" a KWH to a residential customer than in delivering the same amount of electrical energy to a large industrial customer, since in the former case there are additional losses in passage through the low-voltage distribution system. But the major differ, ence in incremental cost of serving different customer class turns upon the timing of the additional KWH, since the major cost differential involved in serving various customers at various times arises from the capacity costs imposed by pea period users --no such costs are imposed by offpeak users. Short run marginal cost is, strictly speaking, different at every moment, as demand fluctuates in relation to capacity In this section we shall see that the variation over time what can be explicitly identified as marginal generation cost is not extreme. Later, in Section IV, we will therefore feel justified in using as an approximation a time-indepen and constant marginal cost of generation.

Any electric utility has in operation, at any given time, plants of varying vintage and consequently of varing economic efficiency. The trend to larger capacity units which exploit economies of scale in generation has left all systems with a spectrum of plant from oldest and least efficient to newest and most efficient. A cost-minimizing management will meet any given load on the system by firing plants in decreasing-efficiency order.* Thus, given a list of all plants owned by a given system and the unit production costs of boiler-turbine-generator combination in each plant, we can construct a first and most naive estimate of marginal generation costs which we refer to as SRMC(1). This function specifies the marginal cost of a KWH, given any load, subject to the assumption that all units at all plants are functioning. Table 8 below lists what Federal Power Commission Form 1 calls "total production cost per KWH" for individual plants, with those plants ranked from least efficient to most efficient. The FPC "total production cost" concept includes some small fixed costs, such as the salaries of plant personnel. But because these are negligible in comparison with the fuel cost component, "total production cost" per KWH is a reasonable measure of fuel cost per KWH. And, with some important qualifications discussed below, fuel cost per KWH is a reasonable measure of short run marginal cost. Figure 1 depicts SRMC(1). (As the table and figure captions indicate, 1972 Potomac Electric Power Company data is used here and elsewhere in the report in describing methodologies.) Table 9, a compilation of fuel efficiency by unit, provides the basis for a stricter measure of marginal cost, given fuel prices. The latter are currently reported to the Federal Power Commission on a monthly basis.

How useful is SRMC(1)? Consider Figure 2, the system load curve for three representative days in three representative

**Under many current interchange and pooling agreements, the pool rather than the utility itself makes the operating decisions.*

Table 8. SHORT RUN MARGINAL COSTS OF GENERATION
Potomac Electric Power Company, 1972

Plant	Total Production cost ¢/KWHR	Cumulative Capability 10^6KW
Morgantown	.454	1.114
Connemaugh	.516	1.273
Dickerson	.598	1.823
Chalk Point	.674	2.533
Potomac River	.725	3.019
Benning Station	.971	3.713
Connemaugh Diesel	1.301	
Buzzard Point	1.3331	4.019
Chalk Point GT	1.530	4.041
Morgantown GT	1.679	4.076
Buzzard Point GT	1.745	4.344
Dickerson GT	2.135	4.367

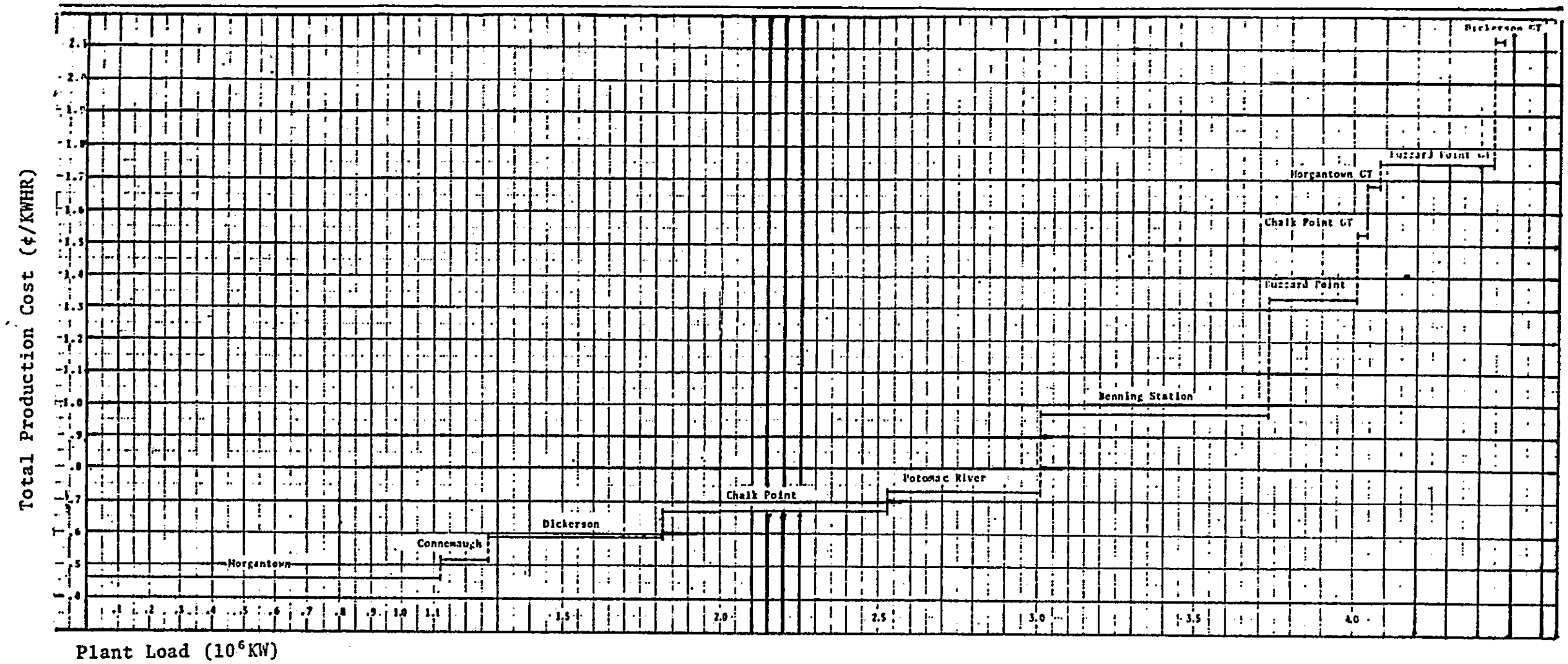

Figure 1. Short Run Marginal Costs, Potomac Electric Power Company, 1972

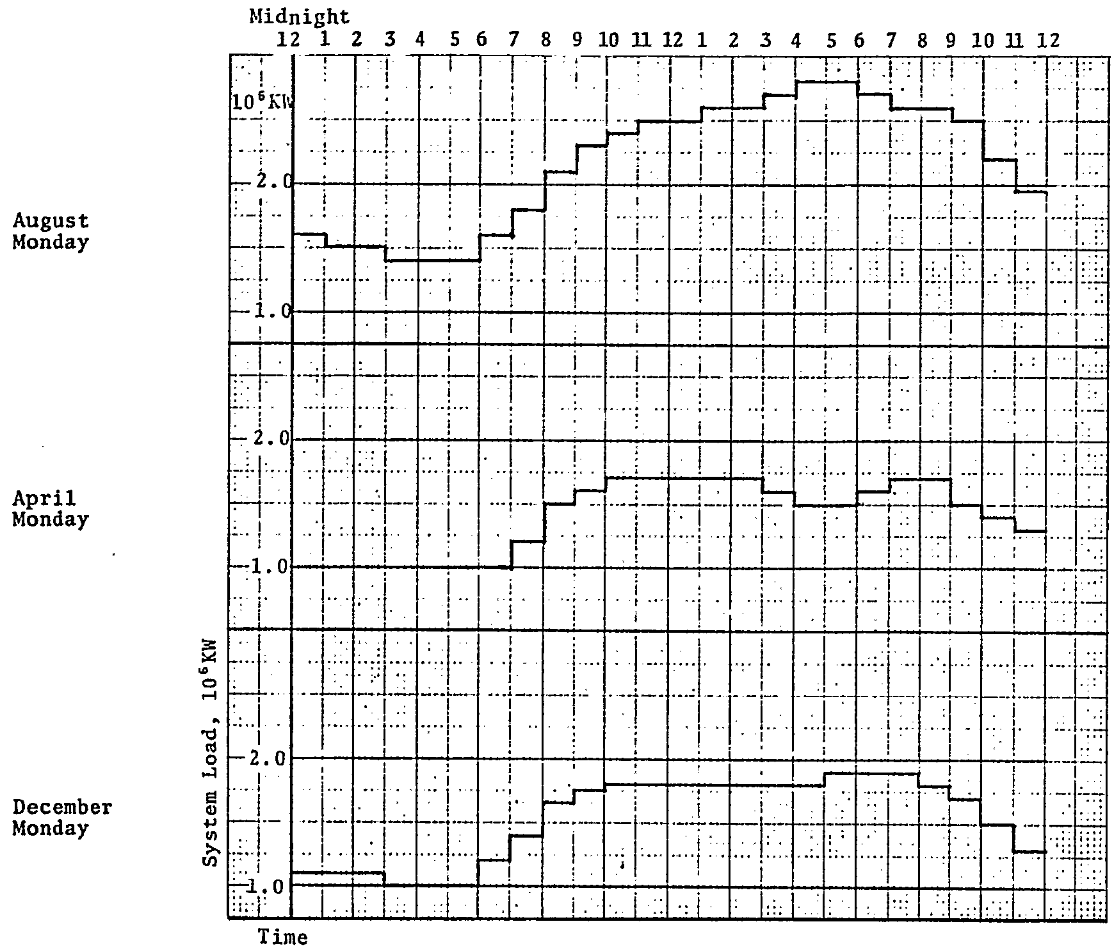

Figure 2. Sample System Load Curves, Potomac Electric Power Company, 1972