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The Economic and Environmental Benefits from Improving Electrical Rate Structures

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THE ECONOMIC AND ENVIRONMENTAL BENEFITS FROM IMPROVING ELECTRICAL RATE STRUCTURES

By

Mark Sharefkin

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Project Officer

Roger Don Shull
Washington Environmental Research Center
U.S. Environmental Protection Agency
Washington, D.C. 20460

Prepared for
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ABSTRACT

Quantitative estimates of the internal cost savings to be derived from changes in the pricing of electric power are devised and evaluated. The econometric literature on electricity demand is surveyed, and elasticity values are selected which are parameters for the overall benefit measures. A method for using reported utility data to estimate the cost of delivered power--at the system peak and off the system peak, and for each customer class- is devised. Data on five electric utilities is used to make estimates of the potential benefits from improvements in the pricing of electric power, for each customer class in each system. The estimated potential benefits are sufficiently large to merit load curve studies by block for residential customers. Such studies are necessary preliminaries to a definitive assessment of the proposals for so called rate inversion.

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The assistance of Mr. Joseph Kowalski in the empirical work on this project was invaluable. Mark Seidel and Jon Goldstein, project officers at the Environmental Protection Agency, contributed above and beyond the call of duty. Seidel, the original project officer, helped shape the study with his probing questions; and Goldstein's careful reading of the draft final report immeasurably improved the end product. Thanks are also due to Lee Matthews, Katleen Weiss and Sylvie Durand-Jansiac for the painstaking typing of the manuscript and tables.

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 thermal 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) costs 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

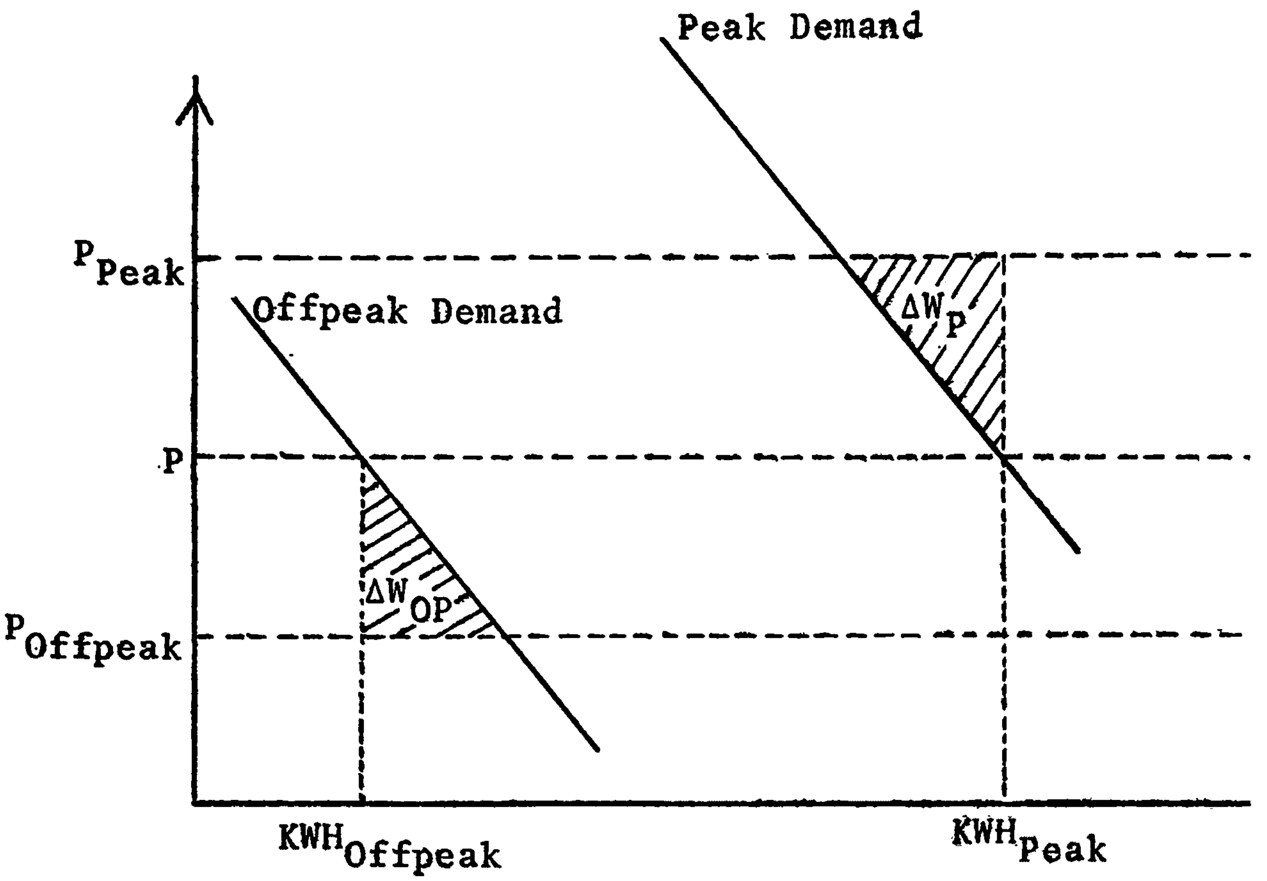

Figure 3. Welfare Gains from Peak Load Pricing

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}, thereby 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 offpeak 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 they are essentially the fuel cost of generating an additional KWH. Strictly speaking, that cost is different from hour to hour, for every electric utility has a stock of generating units of 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 are 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 reproduced 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.

Category I

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 question 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 negligibly small.

Category II

We will compute net benefit measures for all rate schedules of the sample companies as if it were the case that customers are average-price responsive--that they have found it optimal not 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 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 double 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 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 period (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 are 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 analyst's determination of the "true" figure somehow must attach weights to these two bounds, and those weights are unavoidably judgemental. 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 done by many major systems, and some private communications of preliminary 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 price 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.

Category IV

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 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.

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 offpeak 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 monopolies 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 clear 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.

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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 those 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 as 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. Fi nally, 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 non-combination utilities. From this classification we selected

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**Combination utilities sell both gas and electricity; non-combination 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 a 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 $KWH_t(s,b;\alpha)$ refers 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 $t^{\underline{th}}$ 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 $t^{\underline{th}}$ period, in rate schedule α
	$KWH/HH_t[s;\alpha]$	"	KWH sales per household on rate schedule s, in the $t^{\underline{th}}$ period, in region α
	$KWH/B_t[s;\alpha]$	"	KWH sales per customer on rate schedule s, in the $t^{\underline{th}}$ 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 $t^{\underline{th}}$ 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<u>th</u> period, in region α
	$NOMREV_t[s;\alpha]$	"	Nominal revenue per KWH for customers on schedule s, in the t<u>th</u> period, in region α
	$NMQREV_t[s,b;\alpha]$	"	Nominal marginal revenue for customers in block b of schedule s, in the t<u>th</u> period, in region α
	$REREV_t[s,b;\alpha]$		Real revenue per KWH for customers in block b of schedule s, in the t<u>th</u> period, in region α
	$REREV_t[s;\alpha]$		Real revenue per KWH for customers on schedule s, in the t<u>th</u> period, in region α
	$RMQREV_t[s,b;\alpha]$		Real marginal revenue for customers in block b of schedule s, in the t<u>th</u> period, in region α
	$FPC_t[s,500,\alpha]$		Federal Power Commission typical bill for, e.g., customers on schedule s, in the t<u>th</u> 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 $t^{\underline{th}}$ 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 $t^{\underline{th}}$ period, in region α
	$CPIEL_t$		Consumer price index for electricity in the $t^{\underline{th}}$ period
	$CPING_t$		Consumer price index for natural gas in the $t^{\underline{th}}$ period
	CPI_t		General consumer price index in the $t^{\underline{th}}$ period
Dependent Variables: Income	$MFY_t[\alpha]$	Dollars per Year	Median family income, in the $t^{\underline{th}}$ 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 $t^{\underline{th}}$ period
	$PCTURB_t[\alpha]$		Percent of $\alpha^{\underline{th}}$ region living in in urban areas in the $t^{\underline{th}}$ period

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^{th} period, in region α
	$BPC_t[s;\alpha]$		Number of customers per capita on rate schedule s, in the t^{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^{th} period, in region α
	$B_t[s;\alpha]$		Number of bills in rate schedule s, in the t^{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^{th} period) by thermal plants
	$R/IS_t[\alpha]$		Ratio of total residential KWH sales to total industrial KWH sales

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

	Variable	Unit	Definition
Other Variables: Market Characteristic 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

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

$$+ .0355\ \ell n RENG_t[s;\alpha] + .6113\ \ell n MFY_t[\alpha]$$

$$- .3474\ \ell n PCTURB_t[\alpha] = .9245\ \ell n JUTEMP_t[\alpha]$$

$$- .0151\ \ell n TIME(t)$$

$$R^2 = .9031$$

WILSON

$$\ell n\left(\frac{KWH_t[s;\alpha]}{HH_t[s;\alpha]}\right) = 10.25 - 1.33\ \ell n FPC500_t[s;\alpha]$$

$$+ .31\ \ell n NOMNG_t[s;\alpha] - .46\ \ell n MFY_t[\alpha]$$

$$+ .49\ \ell n R/HSE_t[\alpha] - .04\ \ell n DDAYS_t[\alpha]$$

$$R^2 = .566$$

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, goods 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

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

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

$$q\ ar(q) = \int_0^q (dq) mr(q) \tag{2}$$

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

$$\bar{p}\ q^{(1+\beta)} = \int_0^q (dq) mr(q) \tag{3}$$

Differentiating with respect to q we have

$$(1+\beta)\bar{p}q^{\beta} = (1+\beta)ar(q) = mr(q) \tag{4}$$

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, and 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 is that period in which consumer-owner capital, or appliance stocks, cannot be varied in response to demand, so that short run changes in demand in response to price changes are wholly 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 fuel/electricity substitutions cannot proceed without changes in appliance stocks. The appropriate specification of short run 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 relative 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 conflict 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 there must be some adjustment of consumption to changes in short run 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 consumer price index.

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

$$\ell nKWH_t[s;\alpha] = C' + \varepsilon[s;p]\ \ \ell nREREV_t[s;\alpha] + \varepsilon[s;y]\ \ell nDPIPC_t[\alpha] + \ell n \sum_i (W_{it}[\alpha]) \qquad (10)$$

and then take first differences, which gives

$$\ell n KWH_t[s;\alpha] - \ell n KWH_{t-1}[s;\alpha] = C'' + \varepsilon[s;p](\ell n REREV_t[s;\alpha] - \ell n REREV_{t-1}[s;\alpha]) + \varepsilon[s;y](\ell n DPIPC_t[\alpha] - \ell n DPIPC_{t-1}[\alpha]) + \text{white goods term} \quad (11)$$

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

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

Then from (11) and (12) we have

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

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 as 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 good 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,

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

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

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

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

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

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

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, and $\frac{1}{1 - \lambda}\varepsilon[s;F]$ 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 with 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 there 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 estimated in pure cross section and the "long run" elasticity estimated from a pooled sample of time series and cross sections with a 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	$\ell n Q_{t_0}[\alpha]$	$\ell n F[t_0;\alpha]$	$\alpha = 1, 2, \ldots$
Pooled	$\ell n Q_t[\alpha]$	$\ell n Q_{t-1}[\alpha]$,	$t = 1, 2, \ldots$
		$\ell n F[t;\alpha]$	$\alpha = 1, 2, \ldots$

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 $t = t_o$ 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 expression $\left(\frac{\omega}{1 - \frac{\lambda}{1 + r}}\right)$ 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, uses $FPC500_t(s;\alpha)$, 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 all 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:

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

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

$$NOMREV_t = REREV_{t/CPI_t} \tag{25}$$

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 pure 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 of 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 estimation 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 approaches 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 state 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 functional form they finally estimate. For industry j, suppose that output $Y_j(t)$ in period t is produced with electricity input $E_j(t)$ and other inputs $X_k(j,t)$, $k = 1, \ldots m$. 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 $P_j^k(t)$, 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:

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

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:

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

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 in Section IV; it has been located here because, without it, the selection of focus in the cost discussion must seem arbitrary.

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 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. 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 I

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 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-differentiated 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: what 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 these 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 offpeak 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 periods.

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 difference in incremental cost of serving different customer classes 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 peak 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 in 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-independent 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

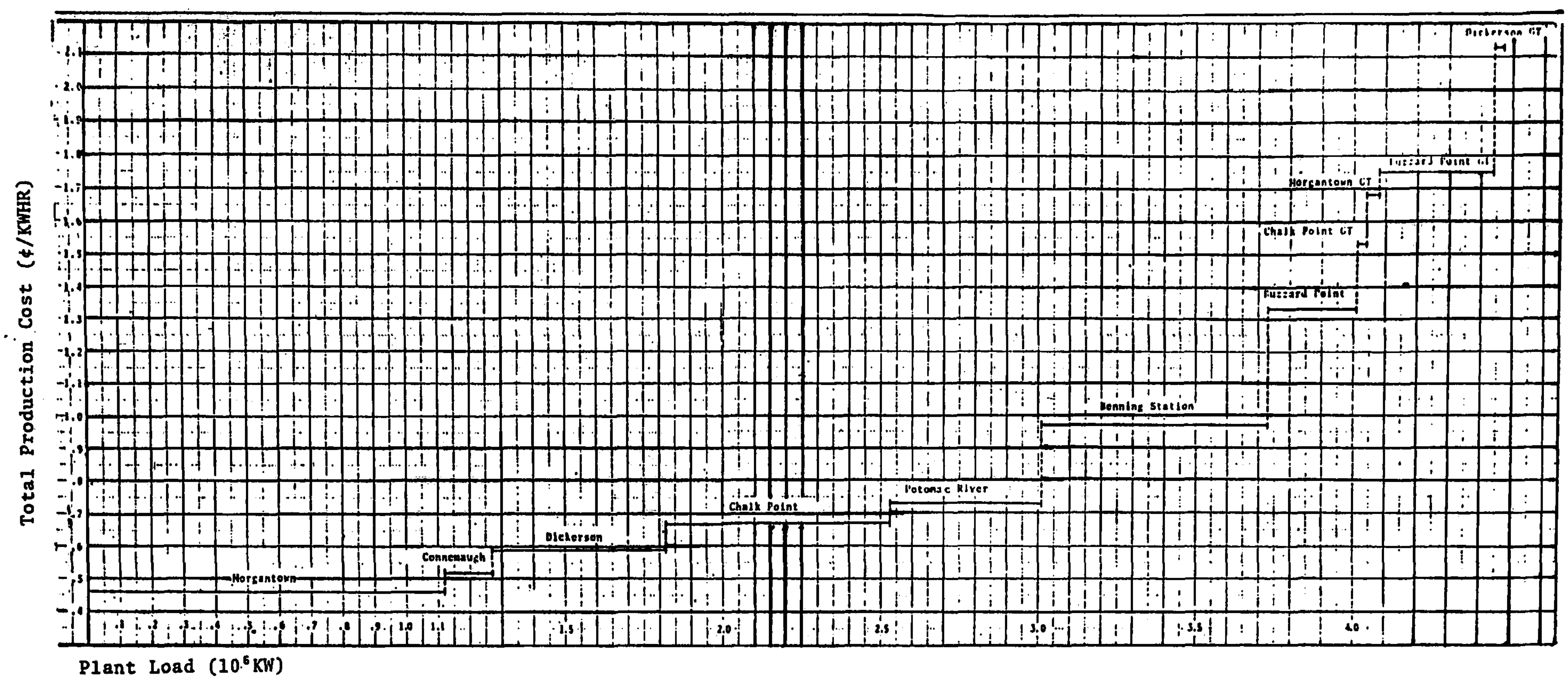

Figure 1. Short Run Marginal Costs, Potomac Electric Power Company, 1972

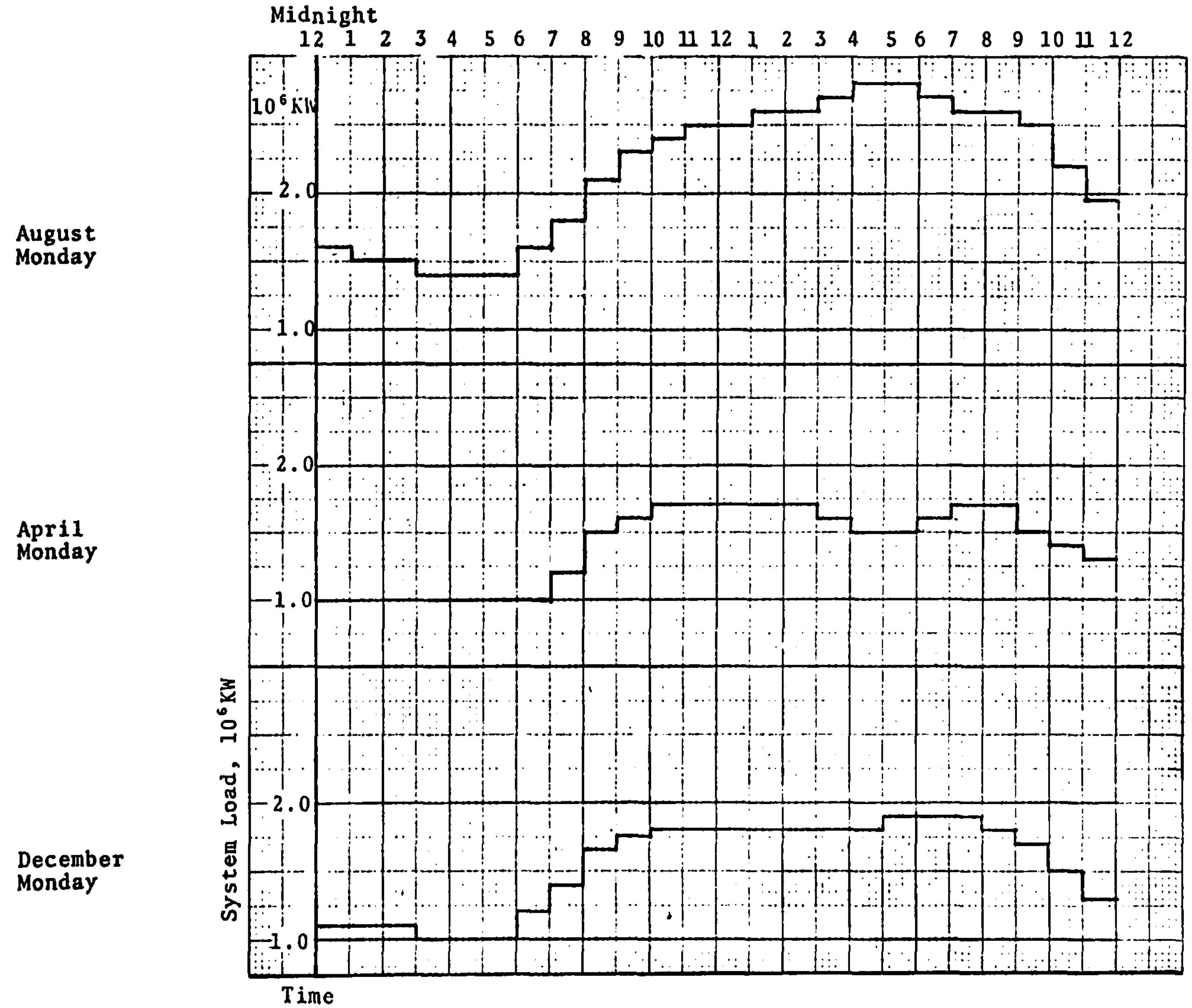

Figure 2. Sample System Load Curves, Potomac Electric Power Company, 1972

Table 9. EFFICIENCY (IN FUEL TERMS) BY UNIT
Potomac Electric Power Company, 1972

Plant	Unit No.	Installation Date	Fuel Type and Rate		Net Continuous Plant Capability	Net Peak Demand On Plant	Gross Capacity	Efficiency
			Coal (tons/hr.)	Oil (gal./min.)			10^3KWH	10^3BTU/KWH
Potomac River	1	1949	38				95	11.0
	2	1950	38				95	11.0
	3	1954	37		486.0	478.0	108	9.0
	4	1956	37				108	9.0
	5	1957	37				108	9.0
Dickerson	1	1959	55				190	
	2	1960	55		550.5	547.0	190	8.7
	3	1962	55		507.0		190	
Dickerson GT						23.0	16.2	
Chalk Point	1	1964	115		710.0	654.0	355	8.5
	2	1965	115				355	
Chalk Point GT						22.0		
Morgantown	1	1970	200	630	1114	1128.0	573	8.6
	2	1971	200	630			575	
Morgantown GT						35.0		

Table 9 (continued). EFFICIENCY (IN FUEL TERMS) BY UNIT
Potomac Electric Power Company, 1972

Plant	Unit No.	Installation Date	Fuel Type and Rate: Coal (tons/hr.)	Fuel Type and Rate: Oil (gal./min.)	Net Continuous Plant Capability	Net Peak Demand On Plant	Gross Capacity 10^3KWH	Efficiency 10^3BTU/KWH
Connemaugh					1640	1732.0	total plant	
Benning Station	10	1927					30.0	
	11	1929	30 total				30.0	
	12	1931					30.0	14.0 combined
	13	1947	23	74	712	720	55.0	
	14	1952	31	100			28.0	
	15	1968		340			289.0	11.0
	16	1972		340			289.0	11.0
Buzzard Point	1	1933		58	288	205	37.5	13.0
	2	1938		58			37.5	13.0
	3	1940		70			57.5	11.0
	4	1942		70			57.5	11.0
	5	1943		70			57.5	11.0
	6	1945		70			57.5	11.0
Buzzard Point Combustion Turbines	(16 Units)			500	(Not applicable since not base load plant)	251	268.0	15.0

How useful is SRMC(1)? Consider Figure 2, the system load curve for three representative days in three representative months (August, April, and December). The comparison with Table 8 reveals that, were all units in the system functioning perfectly with no downtime, the system peak load could be met with ample excess generating capacity in August, the peak month, and with superabundant excess capacity during the seasonal winter trough. Somehow this scenario does not square with the current fears of brownout and blackout, and the problem is one of equipment availability. Every unit, boiler and generator, must be periodically taken "down," inspected, and perhaps repaired or overhauled. A common rule of thumb concerning such scheduled outages is: every boiler must be scheduled for one outage per year, and every generator for one outage every three years. Unfortunately, not all outages are scheduled. "Unscheduled outages," as they are called in the trade--breakdowns or takedowns in anticipation of trouble--are far from infrequent. This supply side uncertainty is not the only source of uncertainty for an electric utility: on the demand side the uncertainty is associated with the unpredictability of load. Trouble can arise from either side, and the problem may be stated as: what are we willing to pay for service of a given quality--one component of that quality index being the guarantee that, with certain probability, all loads will be served? The problem of how much of a capacity margin is necessary is amenable to benefit-cost analysis. We are not aware of any such analysis in the literature on the electric power industry.

If the utilities have based their capacity requirement policies upon such analysis, the process has been implicit. What one finds repeatedly--in the trade literature and in conversation with engineers in utility generating departments--is the citation of rules of thumb. Two are cited more frequently than others: first, that a 20 percent margin of capacity over expected load must be carried, and second, that the system must be able to meet loads even if the largest unit operating at any given point in time should fail.

Such rules of thumb should be replaced by a more explicit benefit-cost calculus. But our purpose is the reconstruction of short run cost functions "as they are," not as we think they should be. We therefore accept the second rule as binding and proceed with our reconstruction, now with the knowledge that any such reconstruction turns upon availability assumptions. There are two possible sources of information on availability: individual company data on scheduled and non-scheduled outages of individual units, and Edison Electric Institute (EEI) data. The latter is a compilation, by unit size, of industry availability data, and is therefore closer to what we might call "expected availability" than any one year record for an individual firm. We therefore take the EEI overall availability measure, compute the corresponding expected downtime, and proceed to a "by sight" scheduling of downtime over the course of the year. The capacity margin requirement we impose is, as discussed above, that in any given month capacity on line to be able to meet last year's demand during that month even if the largest on line unit were to fail. The scheduling problem thus defined is, when formulated as a mathematical programming problem, of forbidding complexity. We therefore follow utility practice in scheduling "by sight," guided by the rule: repair your most efficient capacity in the minimum demand months, the next most efficient capacity in the next highest demand months, and so on.

Table 10 presents the results of this exercise for one system in one year. By comparing Column 6 of this table, "Margin if Largest Running Plant Fails," with Table 11, "System Peak Loads by Month," we can verify that the suggested schedule satisfies the rule of thumb discussed above. Finally, given this schedule, the linkage to system short run marginal costs of generation--call this schedule SRMC(2), an improvement in realism over SRMC(1) above--is a simple matter of constructing the SRMC schedule in each month, given the capacity available in that month. Table 12 compiles SRMC(2), for the above repair schedule, in repair period I. Entries in the column headed "SRMC of Generation" are fuel costs per KWH for the least efficient unit that must be operated (in order to meet system load) when the major unit listed in the left-hand column is down for repairs.

Thus we have, in any month, a SRMC schedule reflecting actually available capacity. When placed side by side with the system load curve for any day of that month, we have the cost of generating the marginal KWH during any hour that day or, when averaged over peak hours (respectively off peak hours), the marginal generation cost during peak hours (respectively off peak hours).

SRMC(2) is about the best that can be said about short run marginal costs from Federal Power Commission "total production cost" data. The limitations of this measure have been sufficiently belabored above. Here we re-emphasize two points. First, note the comparatively small variation of SRMC(2) between peak and offpeak periods. From Table 11 note that the January peak load was 1,975 MW. From Table 12 we know that, had availability been as assumed in constructing that table, peak hour short run marginal costs would have been roughly .72¢. Suppose that January offpeak hour demand

Table 10. MONTHLY PEAKS; TRIAL REPAIR SCHEDULE 1, Potomac Electric Power Company, 1972

Month	System Peak Demand 10^6 KW	If Repair	Remaining Capacity 10^6 KW	Largest Plant Running 10^6 KW	Margin if Largest Running Plant Fails 10^6 KW	
January	1.98	Morgantown 1 & 2	2.372	.355	2.017	
February	1.99					
March	1.87	Chalk Point 1 & 2	2.618	.573	2.045	
April	1.94	Dickerson 3				
May	2.33	Dickerson 1 & 2	3.138	.573	2.565	
June	2.73					
July	3.48	No Scheduled Outages				Need Peaking Capacity
August	3.29	No Scheduled Outages	3.518	.573	2.945	
September	3.03					
October	2.04	Benning Station 15 & 16				
November	2.06	Potomac River 3, 4, & 5	2.616	.573	2.043	
December	2.11					

Table 11. SYSTEM PEAK LOAD BY MONTH

Load Data		
Month	Peak Demand 10^6KW	Peak Load Date
January	1.975	17
February	1.990	7
March	1.867	14
April	1.944	20
May	2.331	31
June	2.730	19
July	3.479	21
August	3.288	25
September	3.034	14
October	2.044	6
November	2.061	30
December	2.110	18
Annual Peak	3.479	7-21-72

was roughly 1,000 KW: then the corresponding SRMC(2) estimate is approximately .47¢.

But it would be a mistake to accept even this improved short run marginal cost measure as a reliable guide to "true" peak period short run marginal cost. For, at the peak, short run marginal cost cannot be approximated by incremental fuel costs for generation from baseline capacity. If capacity has been appropriately adjusted to peak demand, the short run cost of serving the marginal peak customer must equal the (long run) cost of serving that customer by expanding capacity. Thus, system long run marginal cost is a better measure of

Table 12. SRMC(2), TRIAL REPAIR SCHEDULE 1
Repair Period I January-February

Plant and Unit	Net Continuous Capability 10^6KW	Last Unit ¢/KWH	Plants Down	Cumulative Available Capability 10^6KW
Morgantown				
1	.557	.4563		
2	.557			
Dickerson				
1	.184			.184
2	.184	.4594		.367
3	.184			.551
Chalk Point				
1	.355	.4706		.906
2	.355			1.261
Potomac River				
3	.108			1.369
4	.108	.5427		1.477
5	.108			1.585
Potomac River				
1	.095	.6633		1.680
2	.095			1.775
Benning Station				
15	.289	.7247		2.063
16	.289			2.352

true peak period short run marginal cost than is SRMC(2). But in order to compute that measure, we need an explicit allocation of capacity costs.

OFFPEAK VERSUS PEAK COSTS: AN EXPLICIT ALLOCATION OF CAPACITY COSTS

We begin that explicit allocation of capacity costs with a few remarks on the somewhat specialized cost terminology employed in the electric power industry.

Electric Utility Costs: Some Nomenclature

Discussions of electric utility costs lean heavily upon four cost "vocabularies." Each will serve us in what follows. For purposes of discussion, we distinguish these vocabularies as the conventional utility, income statement, economic cost, and functional vocabularies. First, we introduce them seriatim; below, we make use of these classifications in apportioning costs between subperiods and between customer classes.

The Conventional Utility Vocabulary--So named (here) because of its origin in the utility literature, this framework classifies the cost of service into energy, capacity, customer and residual costs. Each category specifies one dimension of service, and the dimensions of service provided are presumably independent. Thus energy costs are those associated with the provision of delivered KWHs, all else held fixed. Capacity costs are, similarly, costs incurred for the provision of capacity. Customer costs are those which vary when the number of customers is varied. Among the latter are, unambiguously, the (annualized) installed cost of a meter, and the cost of meter reading. Less unambiguous--it can make a great deal of difference in the calculation of the minimum charge to be recovered from every customer--is the status of customer-related distribution plant. Clearly the wire running from a distribution line to an individual house represents a pure customer cost, a cost incurred in the service of an identifiable customer. But what of the distribution lines and poles? Are they to be subsumed under capacity cost or customer cost? Finally, residual costs are all costs not subsumed under energy, capacity or customer cost categories: for example some, but not all, administrative and general expenses, i.e. such regulatory commission expenses as are independent of the other three "dimensions."

There is much imprecision in this cost classification. In addition to the ambiguities cited above, there is the obviously unsatisfying fiction of independent dimensions of cost incurrence: for example, the cost of providing an incremental KWH depends upon the level of capacity in the system in a complex way. Nevertheless, the persistence of the conventional utility vocabulary is a tribute to the adequacy of certain cost-function approximations implicit in that vocabulary--in the above example, the approximate constancy of energy costs over wide ranges--and to the format in which data are collected and reported. Again, in the above example, production cost is typically reported on a per unit or per plant basis, whereas there is always some small variation of unit efficiency between zero load and maximum load.

The Income Statement Vocabulary--The characteristic framework in which cost data are summarized for the purposes of review of the financial status of the company is a useful point of departure in our later cost calculations, precisely because the income statement categories, aggregative as they are, have definite economic content suggestive of correct allocation procedures. Thus, in 1972, the Potomac Electric Power Company reported summary income statement data as compiled in Table 13. Of the broad cost categories--Operating Expenses, Maintenance Expenses, Depreciation, Federal Income Taxes, Taxes Other than Federal Income Taxes, Interest on Long Term Debt, and Other Interest and Amortization--only Operating Expenses and Federal Income Taxes require further scrutiny, the other categories are clearly assignable--in "conventional utility" terms--to non-energy cost categories. Table 14, obtained from Federal Power Commission Form 1 as filed by the Potomac Electric Power Company for 1972, supplies the breakdown of electric operation expenses between energy and non-energy related costs: only the fuel cost of

Table 13. INCOME STATEMENT DATA, POTOMAC ELECTRIC POWER COMPANY, 1972 (thousands of dollars)

Operating Revenues	272,717
Operating Expenses	94,493
Maintenance Expenses	21,146
Total Operating and Maintenance Expenses	115,639
Depreciation	35,516
Federal Income Tax	10,804
Other Tax	31,844
Total Operating Expenses	193,888
Operating Income, Gross	78,829
Other Income, Net	449
Income Before Interest Charges	79,278
Interest on Long-Term Debts	32,704
Other Interest and Amortization	1,714
Total Interest Charges	34,418
Net Income	44,860

$105,170,553 represents true energy cost, the remainder of total operations costs of $113,386,960 being incurred in ways largely independent of the level of output--e.g., supervision of generation. Depreciation and Texes Other than Federal Income Taxes are subsumed as capacity charges: Depreciation with little further ado, and Taxes Other than Federal Income Taxes because property taxes on assessed valuation should be in rough proportion to value of electric plant in service. There remain customer costs--reported separately for the most part and, with qualifications discussed above arising from ambiguities in the assignment of certain distribution

Table 14: FUNCTIONALIZATION OF OPERATING AND MAINTENANCE COSTS, Potomac Electric Power Company, 1972 (dollars)

GENERATION	
Operation, Supervision and Engineering	484,739
Fuel	105,170,553
Steam Expenses	3,723,141
Electric Expenses	1,972,373
Miscellaneous Steam Expenses	2,033,635
Rents	2,519
Total Operation	113,386,960
Operation Overhead	487,258
Total Maintenance	12,694,220
OTHER POWER GENERATION	
Total Power Production Expenses - Other Power	2,055,885
OTHER POWER SUPPLY EXPENSES	
Purchased (Sold) Power	(56,349,939)
System Control and Load Dispatching	1,194,892
Other Expenses	196,788
TRANSMISSION	
Total Transmission Expenses	320,739
DISTRIBUTION	
Meter Expenses	765,938
Maintenance of Meters	151,815
Total Distribution Expenses	12,791,639
Total Nonmetering Distribution Expenses	12,025,701
CUSTOMER ACCOUNT EXPENSES	
Meter Reading Expenses	978,214
Total Customer Accounts Expenses	5,244,393
Total Metering Expenses	1,895,967
Sales Expenses	2,444,162
ADMINISTRATIVE AND GENERAL EXPENSES	
Total A & G Expenses	21,659,040
TOTAL ELECTRIC O & M	115,638,779

plant, readily identifiable--and what might be called non-depreciation cost of capital charges, the latter category covering Interest, Net Income and Federal Income Taxes. A simplifying device for treating these cost categories, a device which does not violence to the facts, is discussed below in the sample assignment of capacity costs.

The Economic Vocabulary--The distinction between fixed and variable costs is related to, but less precise and useful than, what we have called the conventional utility vocabulary. Fixed costs, those not changing with the level of output, embrace capacity, customer and residual expenses. Variable costs, definitionally those which do vary with output, are closest to energy costs. Why bother to complicate matters with this additional and extremely thin "vocabulary"? Only because it is so familiar that we shall probably inadvertently use it in what follows.

The Functional Vocabulary--Costs are herein classified by the stage of the production process in which they are incurred. In sequence, those stages are generation, transmission and distribution.

A Classification of Capacity Costs

The key first step is the selection of a workable classification of capacity costs. The classification we select, based upon the discussion above, must be exhaustive of all capacity costs identified in the income statement framework. Such an exhaustive classification is as follows:

1. Nonfuel Operation and Maintenance Expenses;
2. Cost of Capital: Rate of Return on Rate Base and Depreciation; and
3. Taxes Other than Federal Income Taxes.

Category 1 has been discussed above, and can be obtained directly from Federal Power Commission Form 1 by subtracting Fuel Cost from Total Operation Cost to give the Total Nonfuel Operation Cost. To these must be added System Control, Load Dispatching Expenses, and Other (nonfuel) Expenses; the result, Total Nonfuel Operation and Maintenance Expenses, is as compiled in the final column of Table 15. The same procedure is applicable to transmission operation and maintenance costs, which are almost wholly "fixed" costs of operating and maintaining the transmission system. Distribution nonfuel operation and maintenance expenses are given directly in Form 1--note the last line of the operation and maintenance distribution category in Table 14--and therefore need not be adjusted a la Table 15. Note that in terms of our cost vocabularies, Table 15 covers one component of capacity cost, and decomposes that component by function.

Consider next Table 16, Cost of Capital: Rate of Return on Rate Base and Depreciation. The title of this table includes some utility jargon, and an explanation may be helpful. Economists customarily define the net cost of capital as equal to the gross cost of capital minus depreciation. When economists study regulated utilities, they are often asked whether a company is earning a "fair (net) return on capital." In practice, a fair return generally means a rate of return sufficient to attract capital into the industry. And in practice, the net return on capital is computed as the product of a "rate of return" times a "rate base." This procedure could not be faulted if the "rate of return" figure used were the opportunity cost of capital, and if the "rate base" figure used were the company's net worth. But how can a regulatory commission determine the opportunity cost of capital? What usually happens is that some very rough approximation to net worth (such as original cost of physical plant) is

Table 15. GENERATION AND TRANSMISSION NONFUEL OPERATION AND MAINTENANCE
Potomac Electric Power Company, 1972
(dollars)

Functional Component of Plant in Service	Total Operation	Fuel	Total Nonfuel Operation	Total Maintenance	System Control and Load Dispatching[a]	Other Expenses[a]	Total Nonfuel O&M Plus
GENERATION							
Total Steam Production Plant	113386960	105170553	8216407	12694220			20910627
Total Other Production Plant	1718671	1714086	4585	2055885			2060470
Total Production Plant					1194892	196788	24362777
TRANSMISSION	155975			164764			320729

[a] *In principle some of these expenses are allocable between modes of generation. But there is no data available with which to make the allocation, so that we must attribute these expenses to overall generation.*

Table 16. COST OF CAPITAL: RATE OF RETURN ON RATE BASE AND DEPRECIATION, Potomac Electric Power Company, 1972 (dollars)

Functional Component of Plant in Service	Plant in Service: Balance at End of Year	Cost of Capital at 8 Percent of Original Cost	Depreciation at Composite Rate[a]	Gross Cost of Capital
GENERATION				
Total Steam Production Plant	558,409,172	44,672,734	16,417,230	61,089,964
Total Other Production Plant	30,203,993	2,418,151	888,670	3,306,821
Total Production Plant	588,636,054	47,090,884	17,305,900	64,396,785
TRANSMISSION				
Total Transmission Plant	200,706,727	16,056,538	5,900,778	21,957,316

taken as the "rate base," and some rough estimate of the opportunity cost of capital is taken as the "rate of return." All that matters is the product of these two numbers, which is the "target" net income allowed the company.

The purpose of Table 16 is the compilation, in a form convenient for allocation procedures, of the cost of capital in terms of the income cost vocabulary. The relevant categories are (recall the income statement categories in Table 13) Depreciation, Federal Income Taxes, Interest on Long Term Debt, Other Interest and Amortization Charges, and Net Income. Treating these income statement categories seriatim, we begin with Depreciation. Conceptually the least ambiguous of the cost of capital categories, our difficulties in the treatment of depreciation arise from the wide variations in economic lifetime of the capital stock held by electric utilities, and the practice of reporting only the total depreciation category found in Form 1. Thus generating plant may have an economic life of twenty years--many older units are still in service--whereas underground distribution plant may function for fifty or more years. Public Service Commissions typically will assign allowed rates of depreciation for specific types of equipment. A composite straight line rate will then be computed by weighting equipment-specific rates by some weights related to the division of plant in service between various equipment types.

Our procedure in assembling depreciation estimates by function begins by computing an "effective" composite straight line rate in force, that "effective" rate being defined as the ratio of total depreciation charges to end-of-year electric plant in service. (A minor ambiguity surrounds the use of end-of-year electric plant since, for plant completed during the year, something less than an annual depreciation charge at the composite straight line rate is appropriate. The "effective" electric plant in service is somewhere between beginning-of-year and end-of-year plant in service.) Table 17, derived from Federal Power Commission Form 1, assembles electric plant in service by function. Application of the imputed composite straight line depreciation rate to functionally identified plant in service gives the column of Table 16 headed Depreciation at Composite Rate.

Table 17. ELECTRIC PLANT IN SERVICE, Potomac Electric Power Company, 1972 (dollars)

Electric Plant in Service	End-of-Year
Total Intangible Plant	75,578
Total Steam Production Plant	558,409,172
Total Other Production Plant	30,203,993
Total Production Plant	588,636,054
Total Transmission Plant	200,706,721
Distribution Plant:	
Land and Land Rights	8,806,101
Structures and Improvements	18,439,647
Station Equipment	46,641,883
Poles, Towers, Fixtures	25,775,660
Overland Conductors and Devices	29,860,660
Underground Conduits	89,960,956
Underground Conductors and Devices	67,877,917
Line Transformers	86,938,999
Services	52,965,185
Meters	21,300,501
Installation on Customer Premises	2,347,571
Street Lights and Signals	26,092,906
Total Distribution Plant	478,008,178
Total General Plant	27,160,981
Total Electric Plant in Service	1,284,587,512

Turning next to the net cost of capital concept--the opportunity cost of capital which is present even in the absence of economic depreciation--our method is pegged to an eight percent rate of return on original cost. That computed figure appears in the column of Table 16 headed Cost of Capital at 8 Percent of Original Cost. The sum of that pure cost of capital and of the depreciation estimate leads to a Gross Cost of Capital estimate. Since electric plant in service is already broken out by function, the Gross Cost of Capital estimate is likewise automatically broken out by function. Finally, only the third component of our simplified cost of capital classification remains. Table 18, Taxes Other than Federal Income Taxes, allocates such taxes among functionally specified components of electric plant in service in proportion to electric plant in service. The validity of that proration as a reasonable measure of cost incurrence associated with various facilities depends upon the assumption that indirect business taxes are levied in proportion to assessed valuation, with the later assessment assumed to reflect the costs of services provided by state and local governments.

In Table 19, Summary of Functionalized Capacity Costs, the three simplified capacity cost components--Nonfuel Operation and Maintenance Expenses, Cost of Capital, and Taxes Other than Federal Income Taxes--are summed for each function, with the last column, the sum, giving total capacity cost responsibility by function. Note that this table includes, albeit somewhat out of sequence, the full results for Nonmeter Distribution costs. Calculation of those costs requires that metering costs be deducted from total distribution costs, and this is done below.

Table 18. TAXES OTHER THAN FEDERAL INCOME TAXES
Potomac Electric Power Company, 1972
(dollars)

Functional Component of Plant in Service	Corresponding Original Cost	Fraction of Plant in Service, by Function	Proration of Tax Over Plant
Total Production Plant	559,288,714	.432	14,507,157
Total Transmission Plant	200,706,721	.155	4,941,999
Total Distribution Plant	456,707,678	.353	11,255,003
Total Electric Plant in Service	1,294,587,512		

Table 19. SUMMARY OF FUNCTIONALIZED CAPACITY COSTS,
Potomac Electric Power Company, 1972
(dollars)

Function	Total Nonfuel O & M	Cost of Capital	Taxes Other Than Federal Income Taxes	Total by Function
GENERATION	24,352,777	64,396,785	14,507,157	103,266,719
TRANSMISSION	320,729	21,957,316	4,941,999	27,220,044
NONMETER DISTRIBUTION	11,873,886	49,963,820	11,255,003	73,092,709

Allocation of Capacity Costs Among Rate Schedules: A Preliminary Example

We repeat what we have said several times above: that we have neither the time nor the resources for a fine-grained cost of service study, but that we can tolerate much less. It will prove sufficient to have a fairly accurate comparison of actual versus appropriate patterns of cost recovery. In moving towards that comparison we first sketch what it might mean, and then turn to the actual allocation of the capacity cost components listed in Table 19 among individual customer classes. By a customer class we mean all those customers served on a given rate schedule.

For a guide to how fixed costs are actually recovered, the simplest procedure is to use crude average revenue data. Consider Table 20, Crude Estimates of the Allocation of Capacity Costs Among Customer Classes, Potomac Electric Power Company, 1972; all data derive from Federal Power Commission Form 1 filed by that company in that year. For present purposes it will suffice to take, from our previous work on short run marginal generation costs, a flat, conservative estimate, say .7¢. By subtracting .7¢ from average revenue obtained in the service of the various rate schedules, we obtain the column of Table 20 headed Capacity Costs Recovered per KWH (by Rate Schedule). Multiplying that figure by the average number of kilowatt hours sold under the various rate schedules, we obtain the column Capacity Costs Recovered per Customer by Customer Class. From that column, multiplication by the number of customers served under the various rate schedules gives the column Capacity Costs Recovered by Customer Class.

Table 20. CRUDE ESTIMATES OF ALLOCATION OF CAPACITY COSTS AMONG CUSTOMER CLASSES, Potomac Electric Power Company, 1972

Customer Class	KWH Sold	Revenue $	Average Number of Customers	KWHR Sales per Customers	Revenue per KWHR ¢	Marginal Cost	Capacity Costs Recovered per KWH	Capacity Costs Recovered by Customer Class	Capacity Costs Recovered per Customer
Total Residential	3,128,684,929	77,455,188	391,046	8,001	2.476	.7	1.776	55,565,444	142.1
Total Low Voltage Commercial	6,123,240,159	133,766,262	47,596	128,650	2.185	.7	1.485	90,930,116	1,910.5
Total Large Power	3,181,396,529	45,330,042	239	194,515	1.425	.7	.725	23,065,125	189,685.8
Interchange and Resale	5,803,591,000	56,349,939	--	--	.971	.7	.271	15,727,732	--
							Total Capacity Costs Recovered	$ 185,288,417	

As must be true because of the heavy distribution costs associated with residential service, the highest capacity cost per KWH recovery figure is the residential figure, with remaining rate schedules in the expected sequence: commercial, large power, and interchange and resale. The very low figure for interchange and resale is remarkable. Remember that the .271¢/KWH figure is capacity cost recovery alone; addition of the .7¢ fuel cost leaves us with approximately 1.0¢, about the national average for interchange and resale--bulk power--sales. So much for what we have called the "actual" pattern of cost recovery among rate schedules. We turn to the more difficult problem of specifying a serviceable version of what we have called the "appropriate" pattern of cost recovery.

ESTIMATES OF PEAK RESPONSIBILITY CAPACITY COST RECOVERY

As an illustration of the methods we will use to compare actual and "appropriate" patterns of cost recovery, we compare here a measure of peak responsibility generation costs with the cost recovery measures developed in Table 20. (Transmission and distribution costs will of course be included in the final estimates. By temporarily leaving them out of the picture we can illustrate, independently of the ambiguities which bedevil transmission and distribution cost allocations, the crucial cost differentials between off peak and peak power.) Since all peak period users are co-equally responsible for the incurrence of generation capacity costs, these costs are easier to allocate among customer classes than transmission and distribution costs.

First, and seemingly trivially, how to define "the peak" period? Remember that any load curve is observed under definite prices and will change if those prices change, so the question should be stated: given the load curve obtained under present prices, what is "the peak"? As in other places above, we have a problem susceptible of formalization, but a formalization of such complexity as to be nearly useless. That formal problem is: given a set of (independent or interdependent) demands in several subperiods of a period over which demand is periodic, and given the costs of pricing differentially between periods and of having additional rates, what optimum switching times and rate levels will be selected by a seller seeking to maximize the sum of consumer and producer surpluses? In practice, we might proceed as follows: from the known form of the system load curve (in peak season and off peak season months) we select some band of hours during the peak season as "the peak" hours for the year. One measure of peak responsibility capacity costs to be recovered is then obtained by dividing, for each customer class, fixed costs of generation to be recovered by the number of hours in the peak under various definitions of the peak. Table 21, Number of Hours in Peak Under Various Periodizations, compiles total peak hours (over the year) under three definitions of the daily peak and two alternative definitions of the division of the year between peak and offpeak seasons. The plausibility of these definitions of the peak has been based upon inspection of the system load curve, and the location--both seasonal and time of day--of peak hours will be different for different systems. Nevertheless, the range of "total peak hours" can be taken as applicable to all systems: for any given system, a reasonable definition of the peak will fall within this total hours range. Our initial cost recovery range comparison is therefore based upon one total peak hours range exhibited in Table 21, the four month peak season with an eight hour daily peak period.

Table 21. NUMBER OF HOURS IN PEAK UNDER VARIOUS PERIODIZATIONS

Seasonal Division Assumption	Daily Division Assumption[a]		
	Peak 1pm→9pm = 8 hrs	Peak 9am→9pm = 12 hrs	Peak 3pm→7pm = 4 hrs
Peak Season = 4 months ≅ 96 days	768	1,152	384
Peak Season = 6 months ≅ 180 days	1,152	1,728	576

[a] *Sundays excluded, 4 × 6 = 24 days/months.*

Having adopted a preliminary definition of the peak, we turn, in Tables 22A and 22B, to some initial cost recovery comparisons. (Remember that here, in order to have a clear illustrative example, we are looking at generation costs alone.)

Table 22B is a set of calculations of upper bounds on the number of KWH taken during peak hours for various definitions of "the peak." In Column 1 of that table we have entered the number of hours in the peak period under various periodizations (see Table 21). The first row of Table 22B is computed as follows. In Column 4 of Table 22B we list the peak season months, June through September, corresponding to the choice of the four month season. In Column 5 of Table 22B we enter, for each of those months, the maximum demand upon the system as reported in Federal Power Commission Form 12. Assume that monthly maximum demand is approximately equal to actual system demand during all system peak hours. Then KWH taken during peak hours in any one month is approximately equal to system peak demand times the number of peak hours in a month. By summing over months we get the final column of of Table 22B, Upper Bound on Annual Peak KWH.

That column becomes the third column of Table 22A. But from Table 19 we have an estimate of total generation capacity costs to be recovered, i.e. $103,266,719. Column 5 of Table 22A is computed by dividing this figure by each upper bound figure in Column 4.

Columns 6 through 9 of Table 22A compile the ratios of actual fixed cost recovery per peak KWH to our Column 5 estimates of advisable fixed cost recovery. For example, the first row entry in Column 6, 4.82¢, is equal to the first row entry in Column 5 divided by 1.78¢/KWH. Column 5 is therefore a first, crude estimate of the capacity costs per KWH that "should" have been recovered.

The implications of Table 22A should be stated explicitly. For all definitions of the peak period, presently recovered fixed costs were far exceeded by peak responsibility assignment of fixed costs.

Again, a reminder that Table 22A is an initial comparison, since transmission and distribution costs have yet to be included. When that reckoning is made, it will be seen that results for residential service are much closer to those for commercial and industrial service than presently, so that for all categories of service the conclusions are the same: the deviation of present cost recovery from any reasonable pattern of cost recovery which acknowledges peak responsibility is significant. The implication--that there are realizable gains to be had from peak load pricing--is, in part, the work of Section IV.

Table 22A. INITIAL COST RECOVERY COMPARISONS: GENERATION ONLY, Potomac Electric Power Company, 1972

Total Annual Peak Hours	Hours in Daily Peak	Months in Seasonal Peak	Upper Bound on Peak KWH Sales 10^3KWH	Corresponding[a] Fixed Generation Cost to be Recovered per KWH in ¢	Actual Recovery of All Fixed Costs per KWH[b]			
					Actual Residential 1.78 ¢/KWH	Actual Low Voltage Commercial 1.49 ¢/KWH	Actual Large Power .73 ¢/KWH	Actual Interchange and Resale .27 ¢/KWH
					Ratios of Column 5 to Actual			
384	4	4	1,202,976	8.58	4.82	5.76	11.75	31.78
576	4	6	1,622,976	6.36	3.57	4.27	8.71	23.56
768	8	4	2,405,952	4.29	2.41	2.88	5.88	15.89
1,152	12	4	3,608,928	2.86	1.61	1.92	3.92	10.59
1,152	8	6	3,245,952	3.18	1.79	2.13	4.36	11.78
1,729	12	6	4,868,928	2.12	1.19	1.42	2.90	7.85

[a] *Based upon total fixed generation cost to be recovered ≡ $103,266,719 (Table 19 above).*

[b] *Based upon Table 20, Crude Estimates of Allocation of Capacity Costs Among Customer Classes.*

Table 22B. RANGE OF TOTAL PEAK HOURS, AND CORRESPONDING APPROXIMATE TOTAL KWH SALES, Potomac Electric Power Company, 1972

(Total) Annual Peak Hours	Hours in Daily Peak	Months in Seasonal Peak	Months	System Peak Demand in Those Months 10^3KW	Σ System Peak Demands, 4 Month and 6 Month Cases 10^3KW	Monthly Peak Hours	Upper Bound on Annual Peak KWH
384	4	4	June	2,730			1,202,976
			July	3,479	(12,531)	96	
			August	3,288			
			September	3,034			
576	4	6	May	2,331		96	1,622,976
			June	2,730			
			July	3,479	(16,906)		
			August	3,288			
			September	3,034			
			October	2,044			
768	8	4			(12,531)	192	2,405,952
1,152	12	4			(12,531)	288	3,608,928
1,152	8	6			(16,906)	192	3,245,952
1,728	12	6			(16,906)	288	4,868,928

Extension to Transmission and Distribution Costs

A full comparison of costs and benefits associated with peak responsibility pricing obviously requires a full reckoning of all costs--not just the generation costs discussed above--of serving peak and offpeak users. We have used generation capacity costs in our illustrative example for, with the obvious qualification regarding losses, every KW of demand at the system peak is equally responsible for the incurrence of generation capacity costs, and therefore must share co-equally in that cost burden. But transmission and distribution capacity costs are, equally obviously, not so simply interpretable. Clearly the line of causal responsibility for the incurrence of these costs is nowhere as simple as in the case of generation. To take only the most obvious example, any reasonable assignment of distribution capacity costs must show a highly disproportionate assignment of such costs to residential customers, since there are so many more of them and since each requires a separate connection. We believe the crude allocation introduced below is adequate for our later purposes, and we proceed to illustrate that allocation.

First, an allocation of transmission capacity costs among rate schedules. Table 23, Transmission Capacity Cost Allocation, begins this process with an apportionment of total transmission capacity costs between interchange and resale and all other customer classes--in the case of our illustrative system, the Potomac Electric Power Company, the other categories are Residential, Commercial, and Industrial.

Interchange and resale agreements are agreements between companies to "interchange" electric energy under certain specified conditions and at certain specified times. Such agree-

Table 23: TRANSMISSION CAPACITY COST ALLOCATION, Potomac Electric Power Company, 1972

Total 'Fixed' Transmission Cost	Interchange and Resale KWH	Total Residential KWH	Total Low Voltage Commercial KWH	Total Large Power KWH	Total Non-Interchange KWH	Interchange and Non-Interchange	Inter-change KWH as Fraction of Total KWH	Allocation of Total Fixed Transmission Cost to Interchange	Non-interchange KWH as Fraction of Total KWH	Allocation of Total Fixed Transmission Cost to Noninterchange
$27,220,044	5,803,591	3,128,685	6,123,240	3,181,397	12,433,322	18,236,913	.318	$8,655,974	.682	$18,564,070

Total Non-interchange 'Fixed' Transmission Costs	Average Number of Residential Customers	Average Number of Low Voltage Commercial Customers	Average Number of Large Power Customers	Sum of Averages	Residential Customers as Fraction	Allocation of Transmission to Residential	Commercial Customers as Fraction	Allocation of Transmission to Commercial	Industrial Customers as Fraction	Allocation of Transmission to Industrial
$18,564,070	391,046	47,596	239	438,881	.891	$16,540,586	.108	$2,004,919	.001	$18,564

ments can benefit both companies: e.g., by (1) taking advantage of differences in the system load curves so that total capacity requirements are reduced, or by (2) allowing each company to expand its capacity at longer intervals and with larger, more efficient plants.

An interchange or resale customer of an electric utility is thus another electric utility. We have therefore allocated transmission capacity costs between interchange and resale and all other customers on a KWH basis; Table 23 sets out the numbers.

Our rationale for the above assignment is the obvious inappropriateness of a number-of-customers based allocation (as is employed below for different purposes) for this first split: clearly one large interchange connection may account for an important portion of a system's fixed transmission costs, but may nevertheless represent a negligible portion of the system's customers. Then the remaining noninterchange and resale fixed transmission costs are allocated among the usual customer classes on a number-of-customers basis, which should be roughly appropriate. For imagine residential, commercial, and industrial customers to be evenly interspersed over a circular region surrounding the generation plant a system operates. Then where individual transmission lines serve individual squares of a grid covering the service area, the number-of-customers allocation would be exact.

For the allocation of distribution capacity costs among customer classes there is a strong case for allocation on a number-of-customers basis. The reason is obvious: distribution costs are most immediately connected with service to individual customers. Strictly speaking, only the drop wire to the house from the distribution system--we have isolated metering expenses--is unambiguously identifiable with service to an individual customer. Nevertheless, the distribution plant required to serve equal squares of grid with roughly equal customer density should be roughly equal. Customer densities do, of course, differ from neighborhood to neighborhood, and in principle these differences could become the justification for differences in rates between neighborhoods and, more important, between localities. But, the American practice has been overwhelmingly opposed to accurate reflection of such cost differentials in rates--in part because a subsidy is thus granted rural areas--and since our objective is a careful comparison of each company's rates with their understanding of costs, we adhere to the number of customers method of apportioning distribution costs among customer classes. Table 24, Distribution Cost Allocation, compiles these results.

The allocations of generation, transmission, and distribution capacity costs among customer classes, and an estimate of the cost recovery per KWH that would have reproduced that allocation, are compiled in Table 25, Summary of Allocation of Capacity Costs. The elements of this matrix give, for each rate schedule and each function--generation, transmission, and distribution--the associated allocation of capacity costs. The numbers in parentheses below the elements of the matrix, labelled as "Naive $/KWH Recovery," are obtained by dividing each matrix element by the number of KWH in "the peak." For purposes of illustration we have taken, in this case, a 768 hour definition of the peak. By a procedure to be described momentarily, we estimate (as an upper bound) that our illustrative system sold 2,405,000 KWH during these peak hours in 1972. Thus the figures in parentheses have the following interpretation: had all fixed costs been recovered during these peak hours in 1972, and had the pattern of consumption

Table 24: DISTRIBUTION COST ALLOCATION
Potomac Electric Power Company, 1972

Nonmetering Distribution Operation and Maintenance						
Total Distribution Operation Expenses $	Meter Expenses $	Nonmeter Distribution Operation Expenses	Total Distribution Maintenance Expenses	Meter Maintenance Expneses	Total Nonmeter Distribution Maintenance Expenses	Total Nonmeter Distribution Operation and Maintenance Expenses
5,690,999	765,938	4,925,061	7,100,640	151,815	6,948,825	11,873,886

Total Nonmeter Distribution Costs	Fraction of Residential Customers	Allocation of Nonmeter Distribution to Residential	Fraction of Low Voltage Commercial Customers	Allocation of Nonmeter Distribution to Low Voltage Commercial	Fraction of Industrial Customers	Allocation of Nonmeter Distribution to Industrial
$ 73,092,709	.891	65,125,604	.108	7,894,012	.001	73,093

Table 25. SUMMARY OF ALLOCATION OF CAPACITY COSTS, Potomac Electric Power Company, 1972

Function	Customer Class				
	Residential	Commercial	Industrial	Interchange and Resale	Total
GENERATION CAPACITY COSTS					$103,266,719
Naive KWH Allocation:					.0429 $\frac{\$}{KWH}$
KWHs to Schedules during peak	647,588 x 10^3KWH	1,268,353 x 10^3KWH	279,009 x 10^3KWH	211,002 x 10^3KWH	
TRANSMISSION CAPACITY COSTS	$16,540,586	$ 2,004,919	$ 18,564	$ 8,655,974	$ 27,220,044
Naive $/KWH Recovery:	(.0255)	(.0016)	(.0000)	(.0410)	
NONMETER DISTRIBUTION CAPACITY COSTS	65,125,604	7,894,012	73,093		73,092,709
Naive $/KWH Recovery:	(.1006)	(.0062)	(.0000)		

remained the same even with such cost recovery practice, fixed costs of generation would have been recovered at the rate of \$.0429/KWH, which figure is obtained as (\$103,266,719/2,405,952 $\times 10^3$)--the ratio of total fixed costs of generation to total peak KWH. But only the total costs of generation are to be divided by total peak KWHs, since only generation capacity costs are commonly incurred. Since we have already apportioned transmission and distribution costs among customer classes--the results of that apportionment are summarized in Table 25, Summary of Allocation of Capacity Costs--those figures must be divided by the number of KWHs taken on peak by the corresponding customer class. The line of Table 25 labelled KWH to Schedules During Peak presents our estimate of individual customer class consumption on peak, to be explained below; then, for example, the entry (.0255) below the matrix element for Transmission/Residential indicates that, had total fixed transmission costs allocable to residential service--\$15,540,586--been recovered from our estimated number of peak KWH taken by residential customers, i.e. 647,588 $\times 10^3$KWH, recovery per KWH would have been \$.0255/KWH. The other bracketed figures are obtained similarly.

Our description of the procedures whereby Table 25 is obtained will therefore be complete once we explain our method for imputing the customer class KWH consumption during peak hours. In principle, it would, of course, be preferable to work from directly measured data--from data on customer class load curves. Some systems do some sampling of some rate classes, and some have a fairly accurate knowledge of the load curves of large individual customers, but very few try seriously to decompose the system load curve into its individual customer class constituents. Of the systems in our sample, only Pennsylvania Power and Light and Commonwealth Edison Company have a fairly accurate grasp of their customer class load curves. Pennsylvania Power and Light, probably the most sophisticated system in the industry in this (and, we suspect, not only in this) respect, actually decomposes the system load curve into customer class load curves; Commonwealth Edison does something similar, but only for the week in which the system peak day occurs.

How serious a limitation is this? We believe that the answer is that it is serious for the systems but not so serious for our purposes. We mean by this peculiar turn of phrase that intelligent rate making requires greater sensitivity to changes in customer class load patterns than now exists; but that for our purposes--the construction of indicators of potential pricing improvement--the distortions are sufficiently large that they survive the crude procedure about to be described. That the procedure is not too crude is, we believe, indicated by our comparison--for Pennsylvania Power and Light--of actual and imputed customer class load curves: the two were found to differ by less than 5 percent in KWH terms.

Table 26, Imputed Customer Class Load Curves, begins this procedure. Under the assumptions that both interchange and resale and industrial loads are flat over the year, the contribution of these loads is removed from total peak KWH. Residential and commercial contributions to the residual peak KWH are taken in proportion to residential and commercial annual KWH consumption. (A similar calculation gives customer class contributions to KWH consumption in offpeak hours during the peak months; those figures will be required in our indicator estimates and are, therefore, also computed in Table 26.)

Table 26. IMPUTATION OF CUSTOMER CLASS LOAD CURVES
Potomac Electric Power Company, 1972

	10^3KWH
Total Peak	2,405,952
Total Interchange, 1972	5,803,591
Fraction $\frac{\text{Peak}}{\text{Year}} = \frac{768}{365 \times 24} = \frac{768}{8,760}$	.0877
Peak Interchange = (.0877)(2,405,952) =	211,002
Total Peak - Peak Interchange =	2,194,950
Total Industrial, 1972	3,181,397
Peak Industrial = (.0877) (Total Industrial) =	279,009
(Total Peak Peak Interchange - Peak Industrial) =	1,915,941
Total Residential, 1972	3,128,685
Total Low Voltage Commercial, 1972	6,123,240
Sum	9,251,925
Fraction Residential	.338
Fraction Low Voltage Commercial	.662
Peak Residential = (.338) (2,405,952)	647,588
Peak Low Voltage Commercial = (.662)(2,405,952) =	1,268,353
June	1,244,243
July	1,614,291
August	1,548,762
September	1,290,016
Total Peak Season	5,697,312
Peak Hour in Peak Season	2,405,952
Total Peak Season Offpeak Hour	3,291,360
Fraction of Total Year Hours in Hours in Peak Season Offpeak Hours $= \frac{2,160}{8,760}$	.2466
Interchange in Peak Season Offpeak = (.2466)(5,803,591) =	1,433,486
Industrial Sales in Peak Season Offpeak =	785,805
Sum	2,219,291
Total Peak Season Offpeak Hour = 3,291,360 - 2,219,291 =	1,072,069
Fraction Residential	.338
Fraction Low Voltage Commercial	.662
Peak Season Offpeak Hour Residential = (.338)(1,072,069) =	362,359
Peak Season Offpeak Hour Commercial = (.662)(1,072,069) =	709,710

Return momentarily to Table 25, Summary of Allocation of Capacity Costs: the above procedure is the one responsible for the row specifying customer class consumption during peak hours. Table 25 thus summarizes the capacity cost dimensions of cost structure which we require in the construction of indicators in Section IV. A similar table must be, and has been, constructed for each system in the sample. These constructions are, typically, much more tedious and somewhat more judgmental than the one we have used as an illustration of the general method, for the simple reason that most system rate schedules are much more complicated--there are many more rate classes--than the system used above. Without further ado, we turn to the work of Section IV.

SECTION IV

THE PRICING OF ELECTRICITY: INDICATORS OF POTENTIAL IMPROVEMENT

The purpose of this chapter is to select and estimate quantitative measures of the improvement possible in the pricing of electricity. Improvement usually can and should be called by its proper name, welfare gain or gain in net benefit. But here we will use the term "indicator" for two reasons. First, our very real ignorance of many crucial features of demand and cost structure suggests modesty. We believe that the measures to be discussed are good order of magnitude estimates and good indicators of where additional demand and cost information might usefully be "bought"--where more fine-grained demand and cost studies could reasonably be expected to pay for themselves in pricing improvements. Second, there are large and difficult to measure external effects associated with the electric power industry. In industries where external effects are small, a total surplus measure of welfare is plausible and acceptable; the difference between what some customer is willing to pay for a unit of the commodity and the opportunity cost of the resources used in producing the commodity is an obviously appropriate measure of the contribution of that unit of the commodity to overall welfare. The difference between an industry with only minor external effects and an industry with major external economies is that in the first case, privately registered costs of producing output are a relatively good measure of the social opportunity costs of producing that output, while in the case of an industry with large external diseconomies, private costs understate social costs. A proposed change in pricing practices which in an internal efficiency sense decreases output and thereby adds $1 to surplus (as computed from demand and private costs) is deserving of more careful attention than a similar proposed change which increases output by enough to add $1 to surplus. In the first case there are more than the $1 in measureable gains, since the decrease in external costs imposed by the industry is a net gain. In the second case, there are less than $1 in gains, since the external costs imposed by the industry are thereby increased.

The direction of this line of argument can be dangerous, for it seems to lead to an argument that computed welfare gains can be aggregated judgementally when there are unmeasured external effects. We draw the line far short of this in what follows, but we find the argument persuasive for asking the usualy questions of welfare economics--how can welfare be increased by changes in pricing--in a somewhat different way, i.e., how can welfare be increased by selective price increases. Put another way, a naive version of the rules for a welfare optimum might be stated as: charge no customer less than the incremental costs of service, nor any customer more than the incremental costs of service. Our effective restatement of that rule is then: in an industry with large external diseconomies, first insure that no customer is being charged less than the full incremental costs of service.

The implementation of this rule we leave to later in the section. We turn to a brief overview of the variety of electricity tariffs and their traditional rationale. Following that is the construction of the indicators of potential pricing improvement.

THE VARIETY OF TARIFFS

There are probably several dozen electricity tariff types in use throughout the world, the precise number depending upon the system of classification. This diversity has its origin in the great variety of electricity systems throughout the world and in the way in which rate structures have evolved. The earliest American electric systems served lighting loads and often charged a flat subscription fee independent of actual consumption--actual consumption was not metered--but presumably based, in some way, upon expected consumption. A particular utility's tariff structure is the product of a long series of incremental changes and therefore reflective of the distinctive history and policies of that system. Nevertheless, several distinctive tariff types are identifiable, and these have been listed in Table 27. The last column of that table, headed Cost Recovery Strategy, summarizes the cost rationale of the corresponding tariff. Since it is essential in what follows that we recognize the valid and invalid content of each tariff rationale, some further explanation is in order.

The decomposition of costs listed is what we have called the conventional utility cost vocabulary. Recall from our discussion of that vocabulary the underlying assumption that the four dimensions of cost therein identified--energy, capacity, customer and residual costs--are, for purposes of rate making, roughly independent dimensions. Suppose we begin with the two-part tariff entry in Table 27. That tariff is the simples to explain. A customer whose monthly bill is computed under such a tariff pays a minimum bill, or meter rent M independent of monthly consumption; that is, the bill even if consumption is zero. The obvious cost rationale for that meter rent is the necessity of

Table 27. TARIFF TYPES AND COST RECOVERY STRATEGIES[a]

Tariff Type	Bill for Consumer Taking: $q(1)$ Off Peak; Elasticity $\sigma(1)$; $q(2)$ On Peak; Elasticity $\sigma(2)$; q In Toto; μ Maximum Demand	Cost Recovery Strategy			
		Energy	Capacity	Customer	Residual
Two-Part Tariff	$M +$			✓	✓
$[M;\varepsilon]$	$q\varepsilon$	✓	✓		
Fixed Energy Block Rates: No meter rent and no seasonal differential $[B(j),\ \varepsilon(j)]$	$\Sigma_1^{S-1} B(j)\varepsilon(j) +$ $(q-\Sigma_1^{S-1} B(j))\varepsilon(S)$ where $\Sigma_1^{S-1} B(j) \leq q \leq \Sigma_1^{S} B(j)$	✓	✓	✓	✓
Energy and Demand: $[B(j);\varepsilon(j)]$ $[D(j);S(j)]$	$\Sigma_1^{Q-1} D(j)S(j)$ $+\ (\mu-\Sigma_1^{Q-1} D(j)S(Q))$		✓	✓	✓
No meter rent and no seasonal differential	$\Sigma_1^{N-1} B(j)\varepsilon(j) +$ $(q-\Sigma_1^{N-1} B(j))\varepsilon(N)$	✓			
Second-Best Marginal Cost Pricing	$[a(1)SRMC(1) + q(2)SRMC(2)] +$	✓			
	$\frac{C(1)q(1)}{\sigma(1)} + \frac{C(2)q(2)}{\sigma(2)}$		✓	✓	✓
Peak Responsibility	$M +$			✓	✓
$[M;P(1),P(2)]$	$P(1)q(1) +$	✓			
	$P(2)q(2)$	✓	✓		

[a]*All symbols are defined in the text.*

covering customer costs--by definition those costs, such as billing and general and administrative expenses and the annualized cost of the drop line connecting the individual customer to the distribution system, independent of consumption. This is perhaps the least controversial of all features of utility rate making, for the obvious reason that the cost incurrence involved is unambiguously identifiable with an individual customer. Next, the two-part tariff customer pays an energy charge ε per unit of consumption q. And there, as indicated in the final column of Table 27, the difficulties and ambiguities begin. For the energy charge must recover both energy and capacity costs imposed upon the utility by the two-part tariff customer. Since capacity charges are being levied at a flat rate independent of the timing of consumption, and since we have argued that any reasonable measure of peak versus offpeak costs gives estimates of peak costs many times higher than offpeak costs, the flat energy charge of the two-part tariff provides perverse incentives: prices offpeak are too high, discouraging consumption unnecessarily, while prices at peak are too low, inefficiently encouraging consumption. This defect, among others, has led to pressure for the abandonment of the two-part tariff, but it should be noted that a two-part tariff may, under some circumstances, be the best possible tariff. Suppose, for example, that all consumers take so little electricity that they will not, within the relevant band of possible peak versus offpeak prices, distinguish between consumption in those subperiods. Then the question facing a rational pricing authority would be that of the best single energy charge.

Next, in Table 27, consider the characteristic type of residential rate, the fixed block rate. In general that tariff is specified by a block structure $\{B(j)\}$ and a structure of intrablock charges $\varepsilon(j)$. The first block of KWH is $(0,B(1))$, the second block $(B(1),B(2))$, and so on. Generally, there will be a minimum bill associated with the first block, so that the customer must pay $\varepsilon(1)q$ for consumption q in the interval $0<q<B(1)$. As indicated in Table 27, the bill for a customer in any higher block is obtained by summing over the full "price" of each block below the one in which he falls and then adding the product of the energy charge in his block and his consumption in that block. The row 2, column 2 entry of Table 27 gives the algebraic expression for the bill. S stands for the highest block "covered" by monthly consumption Q, and is formally defined by the inequalities in that Table entry. The energy charge in the relevant block is, in effect, the marginal cost of energy to the customer in the S block. For block structures which are declining, as almost all of them are--i.e.,$\varepsilon(1)>\varepsilon(2)>\ldots$-- the marginal energy charge is below the average energy charge. That average charge can be computed by dividing the total bill by total consumption.

As with the two-part tariff, the interesting question here is that of cost rationale. And as with the two-part tariff, the minimum bill can be identified with the customer component of cost service. But how can we then rationalize the differential effective minimum bills paid by customers in different blocks? For a customer in the second block one may think of the effective minimum charge as the entire first block charge $\varepsilon(1)B(1)$. But for a customer in the third block, whose marginal energy charge must be interpreted as $\varepsilon(3)$, that same interpretation of the first block price as minimum bill and therefore as customer charge will no longer pass master. For that third-block customer is paying a per unit "excess" of ($\varepsilon(2)-\varepsilon(3)$) above his marginal charge for each second-block unit he takes. In short, the identification of customer cost recovery and minimum bill is obscured. The difficulty mentioned above in connection with the two-part tariff is also present here: the line between energy and capacity cost recovery is not finely drawn, so that identical marginal prices obtain off and on peak, with the corresponding problem of perverse incentives.

Consider next the typical tariff applicable to larger users, often called a general service tariff, a category is sometime disaggregated into commercial and industrial rate classes. (Industrial rates are typically designed for larger users with higher volumes and better load factors than commercial rate users.) This tariff amounts to a doubling of the structure of the energy-block rate tariff: there are effectively two block structures, one for the pricing of energy consumption and one for the pricing of maximum demand. Thus this tariff requires that total KWH and also maximum demand, or KW, be metered. As above let $\{B(j)\}$ be the energy block structure and let $\{D(k)\}$ be the demand block structure. Then the third row third column entry of Table 27 gives an algebraic expression for the bill paid by a customer who takes energy q (which puts him in the N^{th} energy block) and whose maximum demand is u, which puts him in the Q^{th} demand block. Thus his first block demand bill is the "length" of that demand block, D(1), times the charge S(1) per KW in that block. Summing the contributions to the demand charge from each of the covered blocks and computing the remainder block charge gives the total demand bill. A similar calculation gives the energy bill, and the customer's total bill is then the sum of energy and demand bills.

The critique of the cost rationale underlying this tariff follows the lines of that given above for the energy block structure alone, but must be extended to the way in which capacity costs are recovered. For the demand block structure is an attempt to explicitly price the capacity costs imposed by the user. Its major difficulty is the noncoincident demand basis of the capacity charge. User A and user B may have the same maximum demand, say 1,000 KW. But if user A's maximum demand comes offpeak, say at 1 a.m., there is no reason to bill him at the same rate as user B, whose maximum demand comes at the instant of the system peak. User A is imposing no resource cost upon society for the provision of capacity to meet his demand (He is imposing a resource cost in the sense of fuel used for generation). User B is imposing the full costs of providing 1,000 KW of capacity. Thus the use of noncoincident demand charges can lead to the same sort of perverse offpeak versus peak incentives as the flat marginal charge tariff.

For completeness, and because several systems in our sample do employ such tariffs, we what are sometimes called sliding block tariffs--tariffs with a mixed structure in which the length of the energy blocks may depend upon maximum demand. Usually the demand block structure is defined by taking the lengths of the various blocks to be proportional to maximum demand μ : if the basic demand block structure is $\{W(1)\}$ then for a customer with maximum demand μ the first demand block is of length $\mu W(1)$, the second of length $\mu W(2)$, and so on. The idea is to penalize customers with "poor" load factors--with maximum demand much higher than average demand -- for the capacity costs they impose. But note that the scheme is based upon maximum customer demand, which may or may not be coincident with the system peak demand. The problem of perverse incentives remains.

The last two row entries of Table 27 are not seen as tariffs in the United States--there are some attempts to introduce peak responsibility principles into bulk power pricing, one of which we refer to below--but are listed as guiding principles for rate making, and because of their relevance to the discussion below. In second-best marginal cost pricing, each user is charged a price which inevitably must differ from the short run marginal cost of serving him--because, since short run marginal cost is below average cost, prices equal to marginal cost would be insufficient to cover cost. But the deviation is arranged to cover cost in a way that least distorts the pattern of consumption that would arise were prices equal to the short run marginal cost measures we have discussed in Section III. The appropriate second best rule is that prices differ from short run marginal costs of service in inverse proportion to demand price elasticities of demand.

This normative rule for utility pricing has been the subject of a great deal of theoretical discussion. The corresponding difficulties of interpretation and implementation have not been so thoroughly treated. Our interpretation and implementation of this rule, which corresponds to Category I of our customer response typology, may be subject to some objection.

Our dicussion of Table 27 concludes with some remarks on the last line of that table. We used the term peak responsibility in the very broad sense of any tariff which attempts to restrict recovery of capacity costs to a charge billed at the system peak; or, in other works, to any tariff the demand charge component of which is a strictly coincident demand charge. The coincidence referred to is coincidence with the system peak. We have indicated that customer and residual costs can and should be recovered in a minimum bill or meter rent M under this tariff; and further that there will be prices per KWH P(1) and P(2) differentiating between off-peak and peak.

So much for this necessary and preliminary overview of tariff structure, which has served to introduce the tariffs and to sketch the structure of the remainder of this Section. For an overview of that structure we must piece together our scattered remarks concerning the perverse incentives provided by the various tariffs with the typology of customer responses set out above. Indeed, it is only now that the role of that typology in guiding the construction of potential pricing gains can be set out.

The remaining four sub-sections of this Section complete the task of constructing indicators of potential gain, with each section treating one category of the typology: the relevant customer classes associated with each category (this subject has been broached above), the interpretation of the corresponding indicator, and the evaluation of that indicator for the companies in the sample.

CATEGORY I INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Category I embraces customers who, for information cost reasons, will not distinguish between peak and offpeak nor between average and marginal price. Very plausibly, residential and small commercial customers belong in this category. Under our assumptions the only signal which registers for these customers is average price, so that the only relevant potential pricing change is a change in average price. Thus the question to pose regarding these customers is as follows: if the average prices charged the various customer classes are not the prices required by second best short run marginal cost pricing, how large are the potential gains associated with realigning these average prices as required by the second best standard? The answer shall prove to be very small, so that average price changes are not prime candidates as instruments of rate structure improvement. A sample calculation for one system should illustrate the orders of magnitude involved.

First, a formal statement of the second-best efficiency conditions which have been stated in words above:

$$\frac{\frac{P_i - \mu_i}{P_i}}{\frac{P_j - \mu_j}{P_j}} = \frac{E_j}{E_i} \qquad i, j = \text{all rate classes} \tag{26}$$

Where P_i and P_j are the average prices charged rate classes i and j respectively, μ_i and μ_j the short run marginal costs of serving those rate classes, and E_i and E_j the elasticities demand of those rate classes. Before launching into the empirical work, some further discussion of equation (26) will probably be helpful. Note first that the equations are necessary conditions for a second best set of(relative) average prices, but that these equations alone are insufficient to determine the second best solution--for that determination we need another equation, the requirement that total revenue equal total cost. Next, in what sense is the solution determined by this set of sufficient conditions "second best"? Remember that first best always means price equal to short run marginal cost. Because electric utilities are required to recover their costs from their customers, and because short run marginal costs are below short run average costs, first best pricing of electric power would lead to deficits. It is necessary to price above short run marginal cost in order to cover costs, and the second best solution is the least distorting way of doing so: it leads to the smallest loss in total welfare (the sum of consumers' plus producer's surpluses). The reader trained in economics may be troubled because this solution seems identical with the pricing policy a discriminating monopolist would pursue. This is true, but there is a crucial difference. The discriminating monopolist is able to capture all of the surplus, consumers' and producer's: the public utility pricing at second best marginal cost leaves consumers with all realized consumer surpluses.

As a first guide to where pricing improvement of this kind may be possible, we construct a comparison table, Table 28, of existing values of "deviation ratios" and "elasticity ratios". The deviation ratio is the left side of equation (26) and the elasticity ratio the right side of that same condition when computed for present values of average price, marginal cost and elasticity: the equation defines second-best prices, so that it only holds when prices have been adjusted to a second-best optimum.

As elsewhere in the report, we use 1972 Potomac Electric Power Company data for illustrative purposes, and for that system we treat, initially, the three rate classes--Residential, Commercial, and Industrial.

For each pairwise combination of customer classes there is a comparison between deviation and elasticity ratios. Thus, for our three customer classes case there are three such comparisons. Again, the efficiency condition (26) holds only

Table 28. DEVIATION AND ELASTICITY RATIOS, POTOMAC ELECTRIC POWER COMPANY, 1972

Numerator \ Denominator	Residential		Commercial		Industrial	
	Deviation	Elasticity	Deviation	Elasticity	Deviation	Elasticity
Residential			1.049	1.357	1.182	1.714
Commercial	.953	.737			1.126	1.263
Industrial	.846	.583	.888	.792		

when prices are optimal, so that present values of deviation ratios--i.e., values based upon present prices and associated marginal costs--will not necessarily equal the corresponding elasticity ratios, and in the case of our trial run utility, for which deviation ratios have been computed and compiled in Table 28, they do not. The deviation ratios computed in Table 28 are based upon average prices associated with sales under each rate schedule, and with a marginal cost figure based upon the marginal unit in use during peak hours in August (cf. our discussion of marginal costs above). The elasticity ratios are based upon elasticity estimates by state and customer class published by Chapman, Tyrell and Mount and discussed in Section II.

A first question suggested by Table 28 is that of consistency: are the (pricing) policy implications of the various comparisons afforded by Table 28 consistent with one another? Since the deviation ratio--for example, for the residential-industrial comparison--is

$$\frac{\dfrac{p_R - \mu_R}{p_R}}{\dfrac{p_I - \mu_I}{p_I}} \tag{27}$$

and since the expression $\frac{p-\mu}{p}$ is montonic increasing in p so long as $\mu>0$, a comparison of deviation and elasticity ratios suggests the following pricing changes: if the present deviation ratio is greater than the corresponding eleasticity ratio, either decrease the "numerator" price or increase the "denominator" price or do both, in order to bring the two ratios closer into line. Conversely, if the present deviation ratio is less than the elasticity ratio, either increase the numerator price, or decrease the denominator price, or both.

Carrying through the three possible pairwise comparisons for the test case summarized in Table 28 leaves us with the following policy implications, presented in Table 29.

Table 29. POLICY IMPLICATIONS OF TABLE 28

Rate Schedule	Direction of Implied Price Chage
Residential	↑
Commercial	↑↓
Industrial	↓

There is no inconsistency associated with the opposing arrows in the commercial price column: it simply happens that the residential-commercial pairing comparison leads to the policy recommendation raise, or lower, or both; whereas the commercial-industrial pairing leads to the policy implication lower or raise or both. We thus may choose residential and industrial prices as "policy instruments" and proceed to a determination of the required changes in their magnitudes, and, following that, of the associated welfare gains.

Now if the revenue constraint is to be continued to be satisfied under the new prices (as it presumably has been under the old) then the changes in residential and industrial prices are not independent, but must satisfy a condition derivable, after some manipulation, from the revenue constraint. That condition is

$$\frac{\delta p_R}{\delta p_I} = \frac{q_I}{q_R} \frac{1 - \Delta_I E_I}{1 - \Delta_R E_R} \tag{28}$$

where Δ_I, Δ_R are the corresponding fractional departures from marginal cost: Δ_I is defined as $\frac{P_I - \mu}{P_I}$, and similarly for Δ_R.

The efficiency condition requires that changes in residential and industrial prices be such as to equate deviation and elasticity ratios

$$\frac{\dfrac{p_R + \delta p_R - \mu_R}{p_R + \delta p_R}}{\dfrac{p_I + \delta p_I - \mu_I}{p_I + \delta p_I}} = \frac{E_I}{E_R} \tag{29}$$

Equations (28) and (29) together determine the required price changes. Solution of a quadratic equation for p_R gives the numerical value of the required change as roughly +.207¢/KWH for the residential price, and -.207¢/KWH for the industrial price. (The near equality of the magnitude of price changes is an "accident" here, and will not--does not--happen in all cases.) Evaluation of the expression for net benefit gives a dollar figure per annum of $\$1.35 \times 10^5$, an almost trivial figure for a system with annual revenues in excess of $\$250 \times 10^6$.

CATEGORY II INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Customers in this category are assumed to find it sensible, for information cost reasons, to distinguish between peak and offpeak consumption, but not between average and marginal price. Thus they will be sensitive only to the possible different average prices charged for electricity off and on peak. Were residential customers to be metered by double register meters, which are preset so as to record offpeak and peak KWH separately, they clearly could be expected to exhibit this kind of price sensitivity. But note that the additional costs of double register metering must then be deducted from whatever indicator of gross benefit we derive. Only for residential users will this netting be necessary. Almost all companies monitor the load curves of their major industrial and commercial customers, so that no additional expense would be involved in moving to a scheme of time-differentiated average pricing for these customers. Smaller commercial and industrial customers are typically metered with a maximum demand meter, a device which records both KWH consumption and maximum demand during the billing period, and must be manually reset to zero when the meter is read. These meters vary widely in cost, but are invariable more costly to install and operate than a double register meter, so that we commit no error of overstatement in our final indicator of feasible benefits for these customers if we assume no change in metering costs under time differentiated average pricing.

We therefore proceed to the estimation of indicators of potential pricing improvement for all rate classes on a common basis. When those estimates are completed, we net out the metering costs for residential customers.

An Overview of the Calculation

It may be helpful to look at a simplified version of the indicator estimate, one which exhibits the essentials of the problem without the inessential problems associated with the numerous rate schedules that some systems have. We therefore take our Potomac Electric Power Company cost information, the work of Section III, and construct Table 30, captioned Bands of Suggested Prices for Peak Months. In the columns headed Generation, Transmission, and Distribution, we have entered, from Table 25, our derived costs to be recovered per KWH figures for the individual functions, cross-classified by customer class. By summing the functional costs for each rate schedule we obtain, for each customer class, an "upper bound" on capacity costs to be recovered during peak season peak hours from that customer class. By further adding an estimate of the marginal costs of generation during peak hours, obtained from our previous analysis of short run marginal cost, we have what may be considered an upper bound on total costs to be recovered from each customer class at peak hours. In Column 3, we record that estimate of marginal generation costs is $.007/KWH. This is certainly an in practice lower bound on costs to be recovered. For purposes of

Table 30. BANDS OF SUGGESTED PRICES FOR PEAK SEASON, POTOMAC ELECTRIC POWER COMPANY, 1972

Rate 'Schedule'	Present Average Price $\frac{\$}{KWH}$	Lower Bound ("SRMC") $\frac{\$}{KWH}$	Generation $\frac{\$}{KWH}$	Transmission $\frac{\$}{KWH}$	Distribution $\frac{\$}{KWH}$	Upper Bound $\frac{\$}{KWH}$
Residential	.02476	.007	.0429	.0255	.1006	.1760
Commercial	.02185	.007	.0429	.0016	.0062	.0577
Industrial	.01425	.007	.0429	.0000	.0000	.0499
Interchange and Resale	.00971	.007	.0429	.0410	.0000	.0909

comparison we have tabulated, in Column 1, average revenue for each customer class. The striking, if unsurprising, comparison is evident for all rate schedules: marginal cost is well below average revenue which, in turn, is far below "peak responsibility" price. Recalling our discussion of peak responsibility pricing above, there will be substantial welfare gains from peak responsibility pricing.

Consider next Figure 3, which with Table 31 presents a first illustrative calculation of the welfare gains available from improved pricing of electricity sold to the various customer classes.

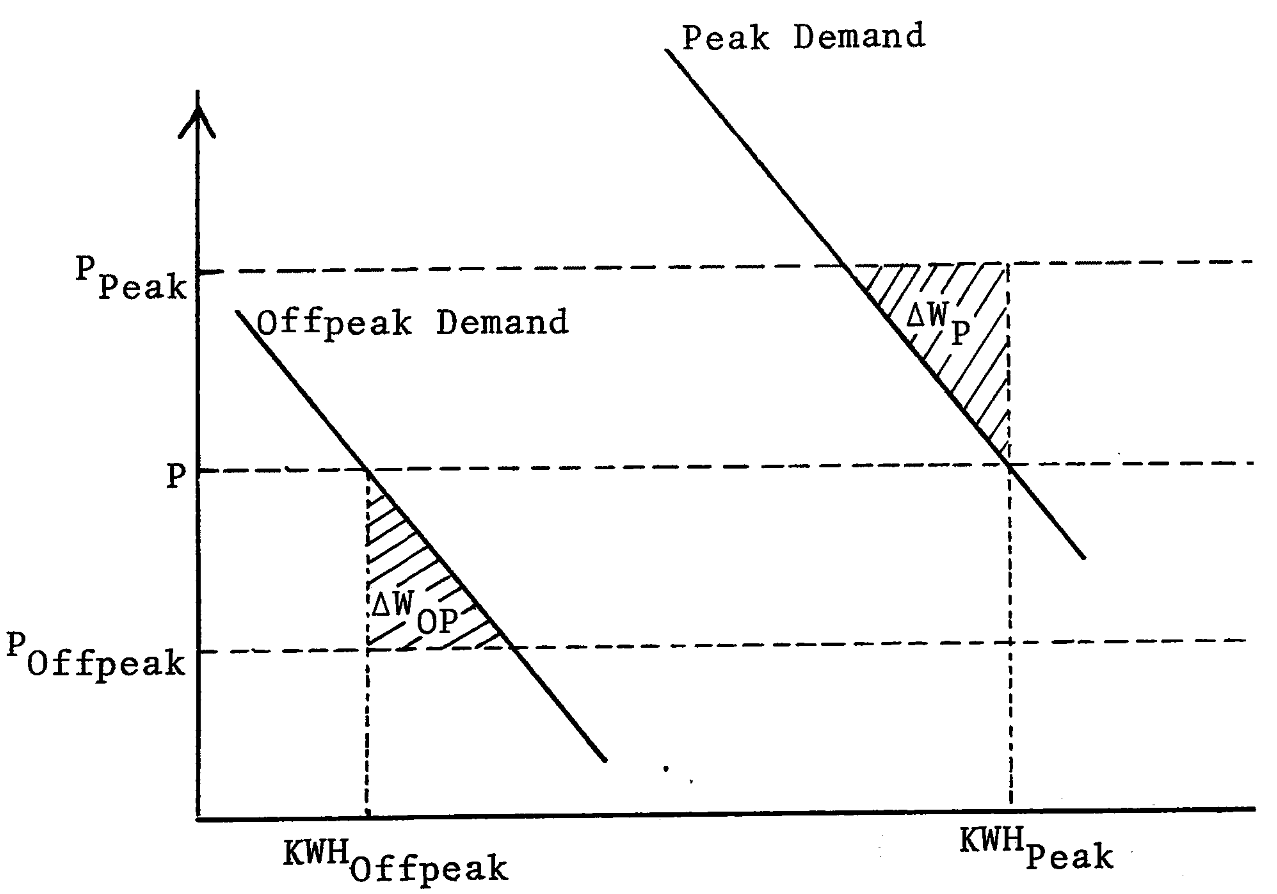

Figure 3. Welfare Gains from Peak Load Pricing

Table 31. ILLUSTRATIVE INDICATORS OF POTENTIAL PRICING IMPROVEMENT, POTOMAC ELECTRIC POWER COMPANY, 1972

					Off Peak Hour, Peak Season Indicator				Peak Hour, Peak Season Indicator			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Rate 'Schedule'	$/\varepsilon/$	Present Average Price $\frac{\$}{KWH}$	Proposed Off Peak Hour, Peak Month Price \$/KWH	Proposed Peak Hour, Peak Month Price \$/KWH	Δp_{op} 2-3	$\frac{\Delta p_{op}}{p_f} = \frac{(5)}{(3)}$	KWH_{op} $10^3 KWH$	$\Delta W_{op} = \frac{1}{2}\varepsilon \Delta p KWH_{op} \frac{\Delta p}{p}$	Δp_{pk} 4-2	$\frac{\Delta p_{pk}}{p_f} = \frac{9}{4}$	KWH_{pk} $10^3 KWH$	$\Delta W_{pk} = \frac{1}{2}\varepsilon \Delta p KWH_{pk} \frac{\Delta p}{p}$
Residential	.14	.02476	.014	.088	.011	.786	362,359	199,370	.063	.716	647,588	2,040,161
Commercial	.19	.02185	.014	.029	.008	.571	709,710	324,196	.007	.241	1,268,353	213,971
Industrial	.24	.01425	.014	.025	.00025	.018	785,805	424	.011	.440	279,009	159,593
Interchange and Resale	.24	.00971	.007	.045	.0027	.386	1,433,486	165,998	.035	.778	211,002	689,470
								Σ 689,988				Σ 3,103,195

ΣΣ 3,793,183

of demand between off peak and peak are taken to be zero. Finally, note that the calculation refers to only those months identified as peak season months in the discussion of Section III. The use of short run elasticities is for illustrative purposes, to indicate the orders of magnitude obtained in such estimates.

We turn now to a more realistic indicator estimate in which some of the restrictive assumptions which make the above example simple are relaxed.

Indicators of Potential Pricing Improvement: Seasonally Spread Peak Responsibility Rates

The above calculation is an instructive guide to the source of the distortions inherent in average cost pricing of electric power, but is insufficient as a benchmark for further analysis. As we have argued in our discussion of short run marginal costs, the notion of "the peak" is complex: at almost any given time the relationship between capacity and demand is different, and in order to reduce that relationship to something upon which rate making can be based, considerable "averaging" over random elements in the relationship--especially the stochastic component of outages--is necessary. Even where the seasonal load curve of a given system exhibits a pronounced peak, the month or season of that peak cannot naively be identified with "the" peak, since the necessity of scheduling downtime for maintenance often means that there is no great surfeit of capacity during the offpeak seasons. If the point of peak pricing is to appropriately penalize those casually responsible for the incurrence of capacity costs, then even peak hour off peak season customers must be so penalized, since much nominally "free" capacity is actually in maintenance during that time.

Present average price P is too high off peak and too low on peak, so that there are welfare losses. The off peak welfare losses ΔW_{OP} arise because off peak customers are being charged more than the marginal costs of serving them. The on peak losses ΔW_P arise because on peak customers are being charged less than the incremental costs of serving them, so that capacity plus operating costs higher than the value of the marginal peak KWH are incurred by the utility and imposed upon society. In terms of Table 30, Figure 3 refers to a single customer class: the appropriate off peak price P_{OP} will be something close to the lower bound for that customer class compiled in Column 3, and the appropriate peak price will be something close to the upper bound compiled in Column 7 of that table. The welfare loss triangles can be computed in terms of ε, the elasticity of the relevant demand schedule, Δ^P, the differential between correct and present average price, and p and q, initial quantities and prices. Those computations are summarized in Table 31, and the expressions for the welfare losses are entered at the heads of Columns 8 and 12 of that table.

In Column 3 of Table 31 we have entered a conservative estimate of proposed offpeak prices, namely twice marginal generation cost, and in Column 4 a similarly conservative proposed peak price, half of our Table 30 "upper bound" peak responsibility price. In Columns 8 and 12 benefits are tabulated by rate schedule, having been computed with the formula at the head of each column. Summation of those benefits gives our estimate of total benefits. The elasticities used in this calculation have been taken as short run elasticities, and are the short run elasticities estimated by Chapman et. al. in the paper discussion in Section II. We have tacitly assumed that these elasticites are identical on peak and off peak, and that the cross price elasticities and therefore they are imposing capacity costs over and above those required to meet the demands of off peak hour, off peak season customers.

But how shall capacity costs be apportioned among seasons? There is, here as elsewhere, no unambiguous allocation, for the underlying problem--akin to the scheduling problem mentioned in connection with short run marginal costs--is a difficult one. The use of several reasonable measures of the relationship of capacity to demand during the three seasons into which we have divided the year--June through September, October through January, and February through May--gives very comparable results, and we have therefore adopted the simplest of procedures in this seasonal allocation of capacity costs, an allocation based upon the seasonal distribution of total energy sales. This means that, e.g., depreciation is apportioned among systems as if it were a pure user cost, incurred only in proportion to output. The ambiguities of the allocation of capacity costs among seasons do not, we feel, blur the basic cost differential, that between the cost of peak hour and off peak hour power during any day of any season. Finally, a word on utility practice in doing what amounts to this allocation. Many summer peak systems do have some rate seasonal differential, but we have found it impossible to get, from any one system, a clear statement of the basis for that differential. We have been told privately by the officials of several systems that the present differential is inadequate. A conjecture which seems to fit the facts is that the interseasonal differential--e.g., the difference between the heights of the residential tailblocks in peak and offpeak seasons--is often taken in a rule of thumb way as the short run marginal cost differential between the most expensive unit in the system and base load plants. The latter differential is typically of the order of 1¢.

Given our allocation of capacity costs by system, rate schedule, and season, our steps in deriving upper and lower bounds for prices can be retraced, and the results are as tabulated in Tables 32 through 36, Bands of Suggested Prices by Season; there is one such table for each system in the sample. The major differential, already evident in our preliminary comparison of Table 30, holds: average pricing substantially underprices peak period power. Also in line with what we have come to expect is the relative size of the differential among rate classes. Thus the commercial load is typically not "as underpriced" as residential and industrial loads. Two explanations for this seem appropriate. First, the commercial load is typically right on peak--nowhere near as flat as the industrial load, and not as spread as the residential load, since the latter has the lighting component late into the evening and an early-morning component. Second, and not entirely fanciful, since it has been suggested to us by personnel at several utilities, residential customers are more numerous, more vocal, and more likely to be the source of complaints. If not having to deal with irate customers is a benefit valued by utility personnel, there should be some bias of rates in favor of residential customers and against commercial customers.

Having thus spread capacity costs "over seasons," we turn to the calculation of indicators of potential pricing improvement by rate schedule and season. Recall Figure 3. Both off peak and peak welfare gains ΔW_{OP} and ΔW_P are based upon internal cost measures, since all our cost estimates (which underlie our peak and off peak price estimates) are based upon internal cost measures. Further, correct pricing of off peak power will result in increased off peak consumption--and increased external cost--while correct pricing of peak power will result in decreased consumption and decreased

Table 32. BANDS OF SUGGESTED PRICES BY SEASON:
Potomac Electric Power Company, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Residential:						
June-Sept.	.007	.0171	.0125	.0493	.0796	
Oct.-January	.007	.0205	.0122	.0479	.0813	.02476
Feb.-May	.007	.0194	.0110	.0433	.0744	
Commercial:						
June-Sept.	.007	.0171	.0008	.0030	.0216	
Oct.-January	.007	.0205	.0008	.0030	.0250	.02185
Feb.-May	.007	.0194	.0007	.0027	.0235	
Industrial:						
June-Sept.	.007	.0171	--	--	.0178	
Oct.-January	.007	.0205	--	--	.0212	.01425
Feb.-May	.007	.0194	--	--	.0201	
Interchange & Resale:						
June-Sept.	.007	.0171	.0137	--	.0315	
Oct.-January	.007	.0205	.0137	--	.0349	.00971
Feb.-May	.007	.0194	.0137	--	.0338	

SRMC = Short-Run Marginal Cost.
LRMC = Long-Run Marginal Cost.

Table 33. BANDS OF SUGGESTED PRICES BY SEASON: Commonwealth Edison Co., 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Small Residential:						
June-September	.0046	.0182	.0469	.0933	.0630	
October-January	.0046	.0182	.0469	.0933	.0630	.0353
February-May	.0046	.0182	.0469	.0933	.0630	
Large Residential:						
June-September	.0046	.0182	.0117	.0233	.0578	
October-January	.0046	.0182	.0117	.0233	.0578	.0302
February-May	.0046	.0182	.0117	.0233	.0578	
Residential Space Heating:						
June-September	.0046	.0182	.0114	.0028	.0370	
October-January	.0046	.0182	.0114	.0028	.0370	.0170
February-May	.0046	.0182	.0114	.0028	.0370	
Small Commercial & Industrial:						
June-September	.0046	.0182	.0017	.0035	.0280	
October-January	.0046	.0182	.0017	.0035	.0280	.0249
February-May	.0046	.0182	.0017	.0035	.0280	
Large Commercial & Industrial:						
June-September	.0046	.0182	--	--	.0228	
October-January	.0046	.0182	--	--	.0228	.0132
February-May	.0046	.0182	--	--	.0228	

Table 33 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Commonwealth Edison Co., 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Street Light & Signal System:						
June-September	.0046	--	--	.0435	.0481	
October-January	.0046	--	--	.0435	.0481	.0209
February-May	.0046	--	--	.0435	.0481	
Water & Sewer Pumping:						
June-September	.0046	.0182	.0001	.0002	.0231	
October-January	.0046	.0182	.0001	.0002	.0231	.0135
February-May	.0046	.0182	.0001	.0002	.0231	
Railroads & Railways:						
June-September	.0046	.0182	.0094	--	.0322	
October-January	.0046	.0182	.0094	--	.0322	.0160
February-May	.0046	.0182	.0094	--	.0322	
Resale, Municipalities:						
June-September	.0046	.0182	.0067	--	.0295	
October-January	.0046	.0182	.0067	--	.0295	.0112
February-May	.0046	.0182	.0067	--	.0295	

Table 34. BANDS OF SUGGESTED PRICES BY SEASON: Duke Power Company, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Residential (R)						
July-October	.0044	.0091	.0174	.0341	.0650	
Nov.-February	.0044	.0091	.0169	.0332	.0635	.0265
March-June	.0044	.0094	.0174	.0341	.0653	
Residential (RA):						
July-October	.0044	.0091	.0046	.0181		
Nov.-February	.0044	.0090	.0045	.0087	.0266	.0167
March-June	.0044	.0094	.0046	.0090	.0272	
Residential (RW):						
July-October	.0044	.0091	.0093	.0181	.0409	
Nov.-February	.0044	.0090	.0090	.0177	.0401	.0201
March-June	.0044	.0094	.0093	.0182	.0413	
Residential (WGS & MISC.):						
July-October	.0044	.0091	.0059	.0115	.0309	
Nov.-February	.0044	.0090	.0058	.0112	.0304	.0155
March-June	.0044	.0094	.0059	.0116	.0313	
Commercial & Industrial (G):						
July-October	.0044	.0091	.0024	.0046	.0205	
Nov.-February	.0044	.0090	.0023	.0045	.0202	.0168
March-June	.0044	.0094	.0024	.0046	.0208	
Commercial & Industrial (GA):						
July-October	.0044	.0091	.0003	.0005	.0143	
Nov.-February	.0044	.0090	.0003	.0005	.0142	.0112
March-June	.0044	.0094	.0003	.0005	.0146	

Table 34 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Duke Power Company, 1974

Rate Schedule by Season (1)	Lower Bound "SRMC" \$/KWH (2)	Generation \$/KWH (3)	Transmission \$/KWH (4)	Distribution \$/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" \$/KWH (6)	Present Av. Annual Price \$/KWH (7)
Commercial & Industrial (I)						
July-October	.0044	.0091	.0001	.0001	.0137	
Nov.-February	.0044	.0090	.0001	.0001	.0136	.0089
March-June	.0044	.0094	.0001	.0001	.0140	
Commercial & Industrial (IP-IS):						
July-October	.0044	.0091	--	--	.0135	
Nov.-February	.0044	.0090	--	--	.0134	.0079
March-June	.0044	.0094	--	--	.0138	
Commercial & Industrial (All Other):						
July-October	.0044	.0091	.0092	.0183	.0410	
Nov.-February	.0044	.0090	.0092	.0183	.0409	.0278
March-June	.0044	.0094	.0092	.0183	.0413	
Street Lighting & Signal System:						
July-October	.0044	.0091	--	--	.0135	
Nov.-February	.0044	.0090	--	--	.0134	.0322
March-June	.0044	.0094	--	--	.0138	
Other Public Authorities:						
July-October	.0044	.0091	.0002	.0004	.0141	
Nov.-February	.0044	.0090	.0002	.0004	.0140	.0105
March-June	.0044	.0094	.0002	.0004	.0144	

Table 34 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Duke Power Company, 1974

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Sales for Resale:						
July-October	.0044	.0091	.0061	--	.0196	
Nov.-February	.0044	.0090	.0061	--	.0195	.0089
March-June	.0044	.0094	.0061	--	.0199	
Interdepartmental:						
July-October	.0044	.0091	--	--	.0135	
Nov.-February	.0044	.0090	--	--	.0134	.0144
March-June	.0044	.0094	--	--	.0138	

Table 35. BANDS OF SUGGESTED PRICES BY SEASON: New York State Electric and Gas Corp., 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Residential:						
Nov.-February	.0047	.0128	.0148	.0336	.0659	
March-June	.0047	.0131	.0146	.0331	.0655	.0272
July-October	.0047	.0130	.0147	.0331	.0655	
General Service (SC2 PSC 113):						
Nov.-February	.0047	.0128	.0049	.0109	.0333	
March-June	.0047	.0131	.0048	.0107	.0333	.0273
July-October	.0047	.0130	.0048	.0108	.0333	
General Service (SC2 PSC 108):						
Nov.-February	.0047	.0128	.0016	.0035	.0227	
March-June	.0047	.0131	.0016	.0035	.0229	.0175
July-October	.0047	.0130	.0016	.0036	.0229	
Large Light & Power (SC3 PSC 113):						
Nov.-February	.0047	.0128	.0001	.0002	.0178	
March-June	.0047	.0131	.0001	.0002	.0181	.0138
July-October	.0047	.0130	.0001	.0002	.0180	
Primary Light & Power (SC3 PSC 108)						
Nov.-February	.0047	.0128	--	.0001	.0176	
March-June	.0047	.0131	--	.0001	.0179	.0103
July-October	.0047	.0130	--	.0001	.0178	

Table 35 (continued). BANDS OF SUGGESTED PRICES BY SEASON:
New York State Electric and Gas Corp., 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Other Public Authority:						
Nov.-February	.0047	.0128	.0013	.0031	.0219	
March-June	.0047	.0131	.0013	.0031	.0222	.0169
July-October	.0047	.0130	.0013	.0031	.0221	
Street Lighting & Signal Systems:						
Nov.-February	.0047	.0128	--	--	.0175	
March-June	.0047	.0131	--	--	.0178	.0486
July-October	.0047	.0130	--	--	.0177	
Interchange & Resale:						
Nov.-February	.0047	.0128	.0115	--	.0290	
March-June	.0047	.0131	.0115	--	.0293	.0080
July-October	.0047	.0130	.0115	--	.0292	

Table 36. BANDS OF SUGGESTED PRICES BY SEASON:
Pennsylvania Power & Light, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Residential (RS):						
Nov.-February	.0047	.0150	.0115	.0413	.0741	
March-June	.0047	.0156	.0119	.0428	.0762	.0271
July-October	.0047	.0139	.0115	.0323	.0624	
Residential (RH):						
Nov.-February	.0047	.0150	.0024	.0085	.0318	
March-June	.0047	.0156	.0025	.0088	.0328	.0171
July-October	.0047	.0139	.0019	.0067	.0272	
Residential (SGS, AL, & CS):						
Nov.-February	.0047	.0150	.0015	.0053	.0277	
March-June	.0047	.0156	.0015	.0055	.0285	.0673
July-October	.0047	.0139	.0011	.0041	.0238	
Commercial & Industrial (SGS):						
Nov.-February	.0047	.0150	.0084	.0304	.0597	
March-June	.0047	.0156	.0087	.0315	.0617	.0426
July-October	.0047	.0139	.0066	.0237	.0489	
Commercial & Industrial (LP3):						
Nov.-February	.0047	.0150	.0002	.0008	.0219	
March-June	.0047	.0156	.0003	.0009	.0227	.0231
July-October	.0047	.0139	.0002	.0007	.0195	

Table 36 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Pennsylvania Power & Light, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Commercial & Industrial (LP4):						
Nov.-February	.0047	.0150	--	.0001	.0210	
March-June	.0047	.0156	--	.0001	.0216	.0153
July-October	.0047	.0139	--	.0001	.0187	
Commercial & Industrial (LP5):						
Nov.-February	.0047	.0150	--	.0002	.0211	
March-June	.0047	.0156	--	.0002	.0217	.0128
July-October	.0047	.0139	--	.0002	.0188	
Commercial & Industrial (LP6):						
Nov.-February	.0047	.0150	--	--	.0209	
March-June	.0047	.0156	--	--	.0215	.0096
July-October	.0047	.0139	--	--	.0186	
Commercial & Industrial (LP):						
Nov.-February	.0047	.0150	.0002	.0008	.0219	
March-June	.0047	.0156	.0002	.0008	.0225	.0128
July-October	.0047	.0139	.0002	.0008	.0196	
Commercial & Industrial (HS)						
Nov.-February	.0047	.0150	.0003	.0010	.0222	
March-June	.0047	.0156	.0003	.0010	.0228	.0166
July-October	.0047	.0139	.0003	.0010	.0199	

Table 36 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Pennsylvania Power & Light, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Commercial & Industrial (BST):						
Nov.-February	.0047	.0150	--	--	.0209	
March-June	.0047	.0156	--	--	.0215	.0092
July-October	.0047	.0139	--	--	.0186	
Commercial & Industrial (All Other):						
Nov.-February	.0047	.0150	.0027	.0096	.0332	
March-June	.0047	.0156	.0027	.0096	.0338	.0243
July-October	.0047	.0139	.0027	.0096	.0309	
Street Lighting and Signal System:						
Nov.-February	.0047	.0150	--	.0036	.0245	
March-June	.0047	.0156	--	.0036	.0251	.0691
July-October	.0047	.0139	--	.0036	.0222	
Other Public Authorities:						
Nov.-February	.0047	.0150	--	--	.0209	
March-June	.0047	.0156	--	--	.0215	.0223
July-October	.0047	.0139	--	--	.0186	
Railroads & Railways:						
Nov.-February	.0047	.0150	--	--	.0209	
March-June	.0047	.0156	--	--	.0215	.0111
July-October	.0047	.0139	--	--	.0186	

Table 36 (continued). BANDS OF SUGGESTED PRICES BY SEASON: Pennsylvania Power & Light, 1972

Rate Schedule by Season (1)	Lower Bound "SRMC" $/KWH (2)	Generation $/KWH (3)	Transmission $/KWH (4)	Distribution $/KWH (5)	Upper Bound (6)=(2)+(3)+(4)+(5) "LRMC" $/KWH (6)	Present Av. Annual Price $/KWH (7)
Interdepartmental:						
Nov.-February	.0047	.0150	--	--	.0209	
March-June	.0047	.0156	--	--	.0215	.0175
July-October	.0047	.0139	--	--	.0186	
Interchange & Resale:						
Nov.-February	.0047	.0150	.0062	--	.0271	
March-June	.0047	.0156	.0062	--	.0277	.0110
July-October	.0047	.0139	.0062	--	.0248	

external cost. In what follows we will therefore take ΔW_p alone, or some measure of ΔW_p alone, as a conservative estimate of potential pricing improvement.

There is inevitably some element of judgement in the selection of a procedure for making those conservative estimates. Peak costs are much higher than average prices, and our econometric evidence on demand elasticities is based upon a relatively much smaller variation around average prices. It therefore would be improper to compute estimates of ΔW_p based upon our full upper bounds--columns 6 of Tables 32 through 36--where those upper bounds are many times higher than present average prices.

In Tables 37 through 41 we have computed two appropriate indicators of potential pricing improvement. First, we have calculated the welfare gain ΔW_{10} associated with a 10% decrease in peak consumption. This requires that we calculate the peak price increase ΔP_{10} over present average price P_{av} necessary to cut peak consumption by 10%, and then that we compute the corresponding welfare gain. In columns 8 of Tables 37 through 41, these welfare gain estimates are presented by system, by season, and by rate schedule. Second, we have computed an estimate of ΔW_p based upon the full upper bound estimates of peak correct peak prices--columns 6 of Tables 32 through 36. As indicated in columns 9 of Tables 37 through 41, we have used that full upper bound directly when it implies less than a doubling of peak price. When use of the full upper bound would imply more than a doubling of present average price, we have taken half the upper bound as the revised peak price. In this way we have computed, for each system, season and rate schedule, a second estimate ΔW_{pk} of ΔW_p. Columns 11 of Tables 37 through 41 summarize the results of this second calculation.

Table 37. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Potomac Electric Power Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $/\epsilon_{av}/$	Present Average Price, P_{av} $/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} $/KWH	LRMC if $\frac{1}{2}$xLRMC<P_{av}, $\frac{1}{2}$xLRMC Otherwise $/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}} x.1$	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Efficiency Gains $\Delta W_{10} = \frac{1}{2}\epsilon_{av}\Delta P_{10}KWH_{pk}\frac{\Delta P_{10}}{P_{av}}$	Efficiency Gain Associated with Upper Bound or One-Half Upper Bound: Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC<P_{av}, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon_{av}\Delta P_{pk}KWH_{pk}\frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential												
June-September	1.22	.0248	.0020	.0398	647,588	.0820	64,784	.0150	.464	2,749,400	- 366,534	- 56.6
October-February	1.22	.0248	.0020	.0406	365,872	.0820	36,601	.0158	.483	1,703,191	- 215,499	- 58.9
February-May	1.22	.0248	.0020	.0372	362,110	.0820	36,225	.0124	.400	1,095,600	- 176,710	- 48.8
Commercial												
June-September	1.46	.0219	.0015	.0216[a]	1,268,353	.0684	94,997	.0003	.014	3,888	+ 25,367	+ 2.0
October-February	1.46	.0219	.0015	.0250[a]	716,594	.0684	53,671	.0031	.132	214,058	- 138,303	- 19.3
February-May	1.46	.0219	.0015	.0235[a]	709,222	.0684	53,119	.0016	.070	57,985	- 72,341	- 10.2
Industrial												
June-September	1.93	.0143	.0007	.0178[a]	279,009	.0518	9,763	.0035	.218	205,432	- 117,463	- 42.1
October-February	1.93	.0143	.0007	.0212[a]	279,009	.0518	9,763	.0069	.389	722,676	- 209,536	- 75.1
February-May	1.93	.0143	.0007	.0201[a]	279,009	.0518	9,763	.0058	.337	526,264	- 181,356	- 65.0
Interchange and Resale												
June-September	1.93	.0097	--	.0157	211,002	.0518	--	.0060	.472	576,643	- 192,222	- 91.1
October-February	1.93	.0097	--	.0175	211,002	.0518	--	.0078	.574	911,634	- 233,790	-110.8
February-May	1.93	.0097	--	.0169	211,002	.0518	--	.0072	.541	793,129	- 220,313	-104.4
					Σ5,539,772		Σ 368,686			Σ9,592,900	Σ-2,128,700	- 38.4

[a]*Full upper bound*

Table 38. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Commonwealth Edison Company, 1972

						Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH		Efficiency Gain Associated with Upper Bound or One-Half Upper Bound				
Rate Schedule by Season	Long Run Average Price Elasticity $/\epsilon_{av}/$	Present Average Price, P_{av} $/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} $/KWH	LRMC if $\frac{1}{2}$xLRMC$<P_{av}$, $\frac{1}{2}$xLRMC Otherwise $/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}} x.1$	Efficiency Gains $\Delta W_{10} = \frac{1}{2}\epsilon_{av}\Delta P_{10} KWH_{pk} \frac{\Delta P_{10}}{P_{av}}$	Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC$<P_{av}$, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon_{av}\Delta P_{pk} KWH_{pk} \frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Small Residential												
June-September	1.22	.0353	.0029	.0630[a]	373,413	.082	54,166	.0277	.564	3,558,591	- 256,908	-68.8
October-January	1.22	.0353	.0029	.0630[a]	364,534	.082	53,603	.0277	.564	3,473,975	- 250,799	-68.8
February-May	1.22	.0353	.0029	.0630[a]	337,766	.082	48,986	.0277	.564	3,218,879	- 232,383	-68.8
Large Residential												
June-September	1.22	.0302	.0025	.0578[a]	2,009,946	.082	251,344	.0276	.627	21,217,272	- 1,529,569	-76.1
October-January	1.22	.0302	.0025	.0578[a]	1,926,150	.082	240,865	.0276	.627	20,332,770	- 1,465,809	-76.1
February-May	1.22	.0302	.0025	.0578[a]	1,818,067	.082	227,349	.0276	.627	19,191,828	- 1,383,549	-76.1
Residential Space Heating												
June-September	1.22	.0170	.0014	.0185	96,632	.082	6,767	.0015	.084	7,427	- 9,856	-10.2
October-January	1.22	.0170	.0014	.0185	94,332	.082	6,606	.0015	.084	7,250	- 9,622	-10.2
February-May	1.22	.0170	.0014	.0185	87,407	.082	6,142	.0015	.084	6,257	- 8,304	-10.2
Small Commercial and Industrial												
June-September	1.48	.0249	.0017	.0280[a]	2,276,368	.068	194,730	.0031	.117	610,972	- 393,812	-17.3
October-January	1.48	.0249	.0017	.0280[a]	2,222,243	.068	190,100	.0031	.117	596,446	- 384,448	-17.3
February-May	1.48	.0249	.0017	.0280[a]	2,059,061	.068	176,140	.0031	.117	552,648	- 356,218	-17.3
Large Commercial and Industrial												
June-September	1.87	.0132	.0007	.0228[a]	1,990,064	.053	69,032	.0096	.533	9,520,880	- 1,984,093	-99.7
October-January	1.87	.0132	.0007	.0228[a]	1,943,283	.053	67,410	.0096	.533	9,297,070	- 1,937,453	-99.7
February-May	1.87	.0132	.0007	.0228[a]	1,800,586	.053	62,460	.0096	.533	8,614,378	- 1,795,184	-99.7
Water and Sewer Pumping												
June-September	1.87	.0231	.0012	.0240	44,175	.053	2,627	.0009	.038	1,413	- 3,136	- 7.1
October-January	1.87	.0231	.0012	.0240	43,124	.053	2,564	.0009	.038	1,379	- 3,062	- 7.1
February-May	1.87	.0231	.0012	.0240	39,958	.053	2,376	.0009	.038	1,278	- 2,837	- 7.1
Railroads and Railways												
June-September	1.87	.0160	.0008	.0161	37,272	.053	1,478	.0001	.006	21	- 410	- 1.1
October-January	1.87	.0160	.0008	.0161	36,386	.053	1,442	.0001	.006	20	- 400	- 1.1
February-May	1.87	.0160	.0008	.0161	33,714	.053	1,337	.0001	.006	19	- 371	- 1.1
Resale, Municipalities												
June-September	1.87	.0112	.0006	.0147	72,474	.053	2,154	.0035	.270	64,036	- 36,599	-50.5
October-January	1.87	.0112	.0006	.0147	70,051	.053	2,083	.0035	.270	88,421	- 35,376	-50.5
February-May	1.87	.0112	.0006	.0147	65,555	.053	1,949	.0035	.270	82,746	- 33,105	-50.5
					Σ19,836,555					Σ100,445,946	Σ-12,113,294	-61.1

[a]*Full upper bound*

Table 39. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Duke Power Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $/\epsilon_{av}/$	Present Average Price, P_{av} $/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} $/KWH	LRMC if $\frac{1}{2}$xLRMC<P_{av}, $\frac{1}{2}$xLRMC Otherwise $/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}}$ x.1	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Efficiency Gains $\Delta W_{10} = \frac{1}{2}\epsilon_{av}\Delta P_{10} KWH_{pk}\frac{\Delta P_{10}}{P_{av}}$	Efficiency Gain Associated with Upper Bound or One-Half Upper Bound: Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC<P_{av}, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon_{av}\Delta P_{pk} KWH_{pk}\frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential (R)												
July-October	1.18	.0265	.0022	325	279,346	.0847	30,711	.0060	.203	201,129	- 67,043	- 24.0
November-February	1.18	.0265	.0022	317	270,234	.0847	29,710	.0052	.179	125,767	- 48,372	- 21.1
March-June	1.18	.0265	.0022	327	225,059	.0847	24,743	.0062	.209	172,329	- 55,590	- 24.7
Residential (RA)												
July-October	1.18	.0167	.0014	270[a]	578,645	.0847	40,483	.0103	.471	1,656,894	- 321,727	- 55.6
November-February	1.18	.0167	.0014	266[a]	559,769	.0847	39,163	.0099	.457	1,493,489	- 301,715	- 53.9
March-June	1.18	.0167	.0014	272[a]	466,193	.0847	30,307	.0105	.478	1,380,398	- 262,933	- 56.4
Residential (RW)												
July-October	1.18	.0201	.0017	205[a]	1,010,966	.0847	85,886	.0004	.020	4,853	- 24,263	- 2.4
November-February	1.18	.0201	.0017	201[a]	977,988	.0847	83,084	00	00	00	- 00	0
March-June	1.18	.0201	.0017	207[a]	814,499	.0847	69,195	.0006	.029	8,308	- 27,693	- 3.4
Residential (NGS & Misc)												
July-October	1.18	.0155	.0013	309[a]	13,302	.0847	864	.0154	.664	80,303	- 10,429	- 78.4
November-February	1.18	.0155	.0013	304[a]	12,868	.0847	836	.0149	.649	73,338	- 9,844	- 76.5
March-June	1.18	.0155	.0013	313[a]	10,717	.0847	696	.0158	.675	67,474	- 8,541	- 79.7
Commercial and Industrial (G)												
July-October	1.13	.0168	.0015	205[a]	891,246	.0885	66,847	.0037	.198	367,682	- 195,747	- 22.3
November-February	1.13	.0168	.0015	202[a]	862,173	.0885	64,666	.0034	.184	312,193	- 183,643	- 21.3
March-June	1.13	.0168	.0015	208[a]	718,045	.0885	53,856	.0040	.213	346,098	- 173,049	- 24.1
Commercial and Industrial (GA)												
July-October	1.13	.0112	.0010	143[a]	548,715	.0885	27,437	.0031	.243	233,890	- 150,897	- 27.5
November-February	1.13	.0112	.0010	142[a]	530,816	.0885	26,542	.0030	.236	213,592	- 141,728	- 26.7
March-June	1.13	.0112	.0010	146[a]	442,080	.0885	22,105	.0034	.263	223,207	- 131,298	- 29.7
Commercial and Industrial (I)												
July-October	1.65	.0089	.0005	137[a]	1,402,182	.0606	35,051	.0048	.425	2,359,032	- 982,930	- 70.1
November-February	1.65	.0089	.0005	136[a]	1,402,182	.0606	35,051	.0047	.418	2,273,639	- 967,506	- 69.0
March-June	1.65	.0089	.0005	140[a]	1,402,182	.0606	35,051	.0051	.445	2,625,643	-1,029,664	- 73.4
Commercial and Industrial (IRES)												
July-October	1.65	.0079	.0005	135[a]	73,954	.0606	1,849	.0056	.523	178,702	- 63,822	- 86.3
November-February	1.65	.0079	.0005	134[a]	73,954	.0606	1,849	.0055	.516	178,821	- 62,935	- 85.1
March-June	1.65	.0079	.0005	138[a]	73,954	.0606	1,849	.0059	.544	195,912	- 66,411	- 89.8
Commercial and Industrial (All Others)												
July-October	1.65	.0278	.0017	410[a]	29,512	.0606	2,509	.0132	.384	123,493	- 18,711	- 63.4
November-February	1.65	.0278	.0017	409[a]	29,512	.0606	2,509	.0131	.381	121,588	- 18,563	- 62.9
March-June	1.65	.0278	.0017	413[a]	29,512	.0606	2,509	.0135	.391	128,486	- 19,035	- 64.5
Other Public Authorities												
July-October	1.65	.0105	.0006	141[a]	18,347	.0606	550	.0036	.293	15,917	- 8,843	- 48.2
November-February	1.65	.0105	.0006	140[a]	18,347	.0606	550	.0035	.286	15,155	- 8,660	- 47.2
March-June	1.65	.0105	.0006	144[a]	18,347	.0606	550	.0039	.313	18,461	- 9,467	- 51.6
Sales for Resale												
July-October	1.65	.0089	.0005	191[a]	510,830	.0606	12,769	.0107	.751	3,386,111	- 632,918	-123.9
November-February	1.65	.0089	.0005	195[a]	510,830	.0606	12,769	.0106	.746	3,332,810	- 628,832	-123.1
March-June	1.65	.0089	.0005	199[a]	510,830	.0606	12,769	.0110	.764	3,542,863	- 644,157	-126.1
Interdepartmental												
July-October	1.65	.0144	.0009	135[a]	461	.0606	21	.0009	.065	22	- 49	- 10.7
November-February	1.65	.0144	.0009	134[a]	461	.0606	21	.0010	.071	27	- 54	- 11.7
March-June	1.65	.0144	.0009	138[a]	461	.0606	21	.0006	.043	32	- 32	- 7.1
					Σ15,327,744		Σ855,378			Σ25,456,636	Σ-7,280,101	- 47.5

[a] Full upper bound

Table 40. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

New York State Electric and Gas, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $\lvert\epsilon_{av}\rvert$	Present Average Price, P_{av} \$/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} \$/KWH	LRMC if $\frac{1}{2}$xLRMC<P_{av}, $\frac{1}{2}$xLRMC Otherwise \$/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}} x.1$	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Efficiency Gains $\Delta W_{10} = \frac{1}{2}\epsilon_{av}\Delta P_{10}KWH_{pk}\frac{\Delta P_{10}}{P_{av}}$	Efficiency Gain Associated with Upper Bound or One-Half Upper Bound: Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC<P_{av}, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon_{av}\Delta P_{pk}KWH_{pk}\frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential												
November-February	1.24	.0272	.0022	.0330	574,163	.0806	63,123	.0058	.193	397,952	- 137,225	- 23.9
March-June	1.24	.0272	.0022	.0328	471,407	.0806	54,826	.0056	.187	306,226	- 109,366	- 23.2
July-October	1.24	.0272	.0022	.0328	497,435	.0806	54,687	.0056	.187	323,131	- 115,405	- 23.2
General Service (SC2 PSC 113)												
November-February	1.65	.0273	.0017	.0333[a]	147,458	.0606	12,533	.0060	.198	144,654	- 48,218	- 32.7
March-June	1.65	.0273	.0017	.0333[a]	120,931	.0606	10,278	.0060	.198	118,632	- 39,544	- 32.7
July-October	1.65	.0273	.0017	.0333[a]	127,991	.0606	10,878	.0060	.198	125,559	- 41,853	- 32.7
General Service (SC2 PSC 108)												
November-February	1.65	.0175	.0011	.0227[a]	86,342	.0606	4,748	.0052	.259	95,857	- 36,868	- 42.7
March-June	1.65	.0175	.0011	.0229[a]	71,023	.0606	3,906	.0054	.267	84,567	- 31,321	- 44.1
July-October	1.65	.0175	.0011	.0229[a]	74,944	.0606	4,122	.0054	.267	89,236	- 33,050	- 44.1
Large Light and Power (SC3 PSC 113)												
November-February	1.89	.0138	.0007	.0178[a]	191,910	.0529	6,716	.0040	.253	183,466	- 91,733	- 47.8
March-June	1.89	.0138	.0007	.0181[a]	191,910	.0529	6,716	.0043	.270	210,429	- 97,874	- 51.0
July-October	1.89	.0138	.0007	.0180[a]	191,910	.0529	6,716	.0042	.264	201,102	- 95,763	- 49.9
Primary Light and Power (SC3 PSC 108)												
November-February	1.89	.0103	.0005	.0176[a]	33,310	.0529	833	.0073	.523	120,123	- 32,910	- 98.8
March-June	1.89	.0103	.0005	.0179[a]	33,310	.0529	833	.0076	.539	128,983	- 33,943	-101.9
July-October	1.89	.0103	.0005	.0178[a]	33,310	.0529	833	.0075	.534	126,037	- 33,610	-100.9
Other Public Authority												
November-February	1.89	.0169	.0009	.0219	73,055	.0529	3,287	.0050	.305	105,199	- 42,080	- 57.6
March-June	1.89	.0169	.0009	.0222	73,055	.0529	3,287	.0053	.272	100,476	- 37,915	- 51.4
July-October	1.89	.0169	.0009	.0221	73,055	.0529	3,287	.0052	.267	95,921	- 36,893	- 50.5
Interchange and Resale												
November-February	1.89	.0080	.0004	.0145	95,913	.0529	1,918	.0065	.578	340,395	- 104,737	-109.2
March-June	1.89	.0080	.0004	.0146	95,913	.0529	1,918	.0066	.584	349,430	- 105,888	-110.4
July-October	1.89	.0080	.0004	.0146	95,913	.0529	1,918	.0066	.584	349,430	- 105,888	-110.4
					Σ3,354,258		Σ254,362			Σ3,996,805	Σ-1,412,084	- 42.1

[a] *Full upper bound*

Table 41. PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Pennsylvania Power and Light Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $/\varepsilon_{av}/$	Present Average Price, P_{av} \$/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} \$/KWH	LRMC if $\frac{1}{2}$xLRMC<P_{av}, $\frac{1}{2}$xLRMC Otherwise \$/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\varepsilon_{av}}$ x.1	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Efficiency Gains $\Delta W_{10} = \frac{1}{2}\varepsilon_{av}\Delta P_{10}KWH_{pk}\frac{\Delta P_{10}}{P_{av}}$	Efficiency Gain Associated with Upper Bound or One-Half Upper Bound: Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC<P_{av}, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\varepsilon_{av}\Delta P_{pk}KWH_{PK}\frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
	1	2	3	4	5	6	7	8	9	10	11	12
Residential (RS)												
November-February	1.22	.0271	.0022	.0370	724,801	.0820	79,760	.0099	.308	1,348,139	- 272,351	- 37.6
March-June	1.22	.0271	.0022	.0381	568,600	.0820	62,571	.0110	.337	1,285,758	- 233,774	- 41.1
July-October	1.22	.0271	.0022	.0312	582,477	.0820	64,098	.0041	.141	205,405	- 100,197	- 17.2
Residential (RH)												
November-February	1.22	.0171	.0014	.0318[a]	361,167	.0820	25,291	.0147	.601	1,946,389	- 264,814	- 73.3
March-June	1.22	.0171	.0014	.0328[a]	283,332	.0820	19,841	.0157	.629	1,706,773	- 217,423	- 76.7
July-October	1.22	.0171	.0014	.0272[a]	290,247	.0820	20,325	.0101	.456	815,425	- 161,470	- 55.6
Residential (SGS, AZ, and CS)												
November-February	1.22	.0673	.0055	.0277[a]	2,138	.0820	588	.0396	-.834	43,072	+ 2,175	+ 1.017
March-June	1.22	.0673	.0055	.0285[a]	1,667	.0820	458	.0388	-.810	31,958	+ 1,647	+ 98.8
July-October	1.22	.0673	.0055	.0238[a]	1,718	.0820	472	.0435	-.955	43,536	+ 2,001	+ 1.165
Commercial and Industrial (SGS)												
November-February	1.46	.0426	.0029	.0597[a]	116,606	.0685	12,343	.0171	.334	486,168	- 56,861	- 48.8
March-June	1.46	.0426	.0029	.0617[a]	91,447	.0685	13,261	.0191	.366	466,667	- 48,865	- 53.4
July-October	1.46	.9426	.0029	.0489[a]	93,709	.0685	13,589	.0063	.138	59,474	- 18,880	- 20.1
Commercial and Industrial (LP3)												
November-February	1.46	.0231	.0016	.0219[a]	439,947	.0685	35,199	.0012	-.053	20.426	+ 34,043	+ 7.7
March-June	1.46	.0231	.0016	.0227[a]	345,134	.0685	27,627	.0004	-.035	3,527	+ 17,636	+ 5.1
July-October	1.46	.0231	.0016	.0195[a]	353,557	.0685	28,287	.0036	-.169	157,026	+ 87,236	+ 2.5
Commercial and Industrial (LP4)												
November-February	1.93	.0153	.0008	.0210[a]	160,438	.0518	6,415	.0057	.314	277,102	- 97,228	- 60.6
March-June	1.93	.0153	.0008	.0216[a]	160,438	.0518	6,415	.0063	.341	344,669	- 105,589	- 65.8
July-October	1.93	.0153	.0008	.0187[a]	160,438	.0518	6,415	.0034	.200	105,279	- 61,929	- 38.6
Commercial and Industrial (LP5)												
November-February	1.93	.0128	.0007	.0211[a]	81,890	.0518	2,865	.0083	.490	321,390	- 77,468	- 94.6
March-June	1.93	.0128	.0007	.0217[a]	81,890	.0518	2,865	.0089	.516	326,909	- 81,562	- 99.6
July-October	1.93	.0128	.0007	.0188[a]	81,890	.0518	2,865	.0060	.380	180,174	- 60,025	- 73.3
Commercial and Industrial (LP6)												
November-February	1.93	.0128	.0007	.0209[a]	188,779	.0518	6,605	.0081	.481	684,918	- 175,249	- 92.8
March-June	1.93	.0128	.0007	.0215[a]	188,779	.0518	6,605	.0087	.507	803,541	- 184,722	- 97.8
July-October	1.93	.0128	.0007	.0186[a]	188,779	.0518	6,605	.0058	.369	389,884	- 134,442	- 71.2
Commercial and Industrial (LP)												
November-February	1.93	.0128	.0007	.0219[a]	44,302	.0518	1,550	.0091	.524	203,856	- 44,789	-101.1
March-June	1.93	.0128	.0007	.0225[a]	44,302	.0518	1,550	.0097	.550	228,079	- 47,004	-106.1
July-October	1.93	.0128	.0007	.0196[a]	44,302	.0518	1,550	.0068	.420	122,098	- 35,929	- 81.1
Commercial and Industrial (NS)												
November-February	1.93	.0166	.0009	.0222[a]	70,321	.0518	3,163	.0056	.289	109,824	- 39,222	- 55.8
March-June	1.93	.0166	.0009	.0228[a]	70,321	.0518	3,163	.0062	.315	132,530	- 42,751	- 60.8
July-October	1.93	.0166	.0009	.0199[a]	70,321	.0518	3,163	.0033	.181	40,533	- 24,565	- 34.9
Commercial and Industrial (BST)												
November-February	1.93	.0166	.0009	.0209[a]	43,036	.0518	1,936	.0043	.229	40,894	- 19,022	- 44.2
March-June	1.93	.0166	.0009	.0215[a]	43,036	.0518	1,936	.0049	.257	52,627	- 21,347	- 49.6
July-October	1.93	.0166	.0009	.0186[a]	43,036	.0518	1,936	.0020	.114	9,469	- 9,467	- 22.0

Table 41 (Continued) PEAK BENEFITS BY SEASON: AVERAGE PRICES COMPARED WITH PEAK PRICES WHICH DECREASE PEAK KWH TEN PERCENT AND WITH LRMC

Pennsylvania Power and Light Company, 1972

Rate Schedule by Season	Long Run Average Price Elasticity $/\epsilon_{av}/$	Present Average Price, P_{av} \$/KWH	Price Change Consis. with a 10 % Decrease in Peak KWH, ΔP_{10} \$/KWH	LRMC if $\frac{1}{2}$xLRMC<P_{av}, $\frac{1}{2}$xLRMC Otherwise \$/KWH	Peak KWH in Season, KWH_{pk} 10^3KWH	Efficiency Gains Associated With a Ten Percent Decrease In Peak KWH: Fractional Price Change $\frac{\Delta P_{10}}{P_{av}} = \frac{1}{\epsilon_{av}} x.1$	Efficiency Gains $\Delta W_{10} = \frac{1}{2}\epsilon_{av}\Delta P_{10}KWH_{pk}\frac{\Delta P_{10}}{P_{av}}$	Efficiency Gain Associated with Upper Bound or One-Half Upper Bound: Price Change at Peak, ΔP_{pk} = LRMC-P_{av} if $\frac{1}{2}$LRMC<P_{av}, = $\frac{1}{2}$LRMC-P_{av} Otherwise	Average Fractional Price Change	Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon_{av}\Delta P_{pk}KWH_{pk}\frac{\Delta P_{pk}}{P_{av}}$	Change in Peak KWH ΔKWH_{pk} 10^3KWH	Percentage Change in Peak KWH
Commercial and Industrial (All Other)												
November-February	1.93	.0092	.0005	.0166	51,917	.0518	1,297	.0074	.574	194,267	- 52,488	- 1.011
March-June	1.93	.0092	.0005	.0169	51,917	.0518	1,297	.0077	.590	227,604	- 59,133	- 1.139
July-October	1.93	.0092	.0005	.0155	51,917	.0518	1,297	.0063	.510	160,971	- 51,086	- 98.4
Other Public Authorities												
November-February	1.93	.0691	.0036	.0209[a]	54	.0518	9	.0482	-1.071	2,690	+ 112	+206.7
March-June	1.93	.0691	.0036	.0215[a]	54	.0518	9	.0476	-1.051	2,607	+ 109	+202.8
July-October	1.93	.0691	.0036	.0186[a]	54	.0518	9	.0505	-1.152	3,032	+ 120	+222.3
Railroads and Railways												
November-February	1.93	.0223	.0012	.0209[a]	12,862	.0518	772	.0014	-.065	1,129	+ 1,607	+ 12.5
March-June	1.93	.0223	.0012	.0215[a]	12,862	.0518	772	.0008	-.037	367	+ 9,183	+ 71.4
July-October	1.93	.0223	.0012	.0186[a]	12,862	.0518	772	.0037	-.181	8,312	+ 4,488	+ 34.9
Interdepartmental												
November-February	1.93	.0111	.0006	.0209[a]	254	.0518	8	.0098	.613	1,472	- 300	-118.3
March-June	1.93	.0111	.0006	.0215[a]	254	.0518	8	.0104	.638	1,626	- 313	-123.1
July-October	1.93	.0111	.0006	.0186[a]	254	.0518	8	.0075	.505	928	- 248	- 97.5
Interchange and Resale												
November-February	1.93	.0110	.0006	.0135	220,131	.0518	6,602	.0025	.204	108,337	- 86,731	- 39.4
March-June	1.93	.0110	.0006	.0138	220,131	.0518	6,602	.0028	.226	134,423	- 95,977	- 43.6
July-October	1.93	.0110	.0006	.0124	220,131	.0518	6,602	.0014	.120	35,688	- 51,070	- 23.2
					Σ6,878,600		Σ497,376			Σ13,912,252	Σ-2,875,374	- 41.8

[a] *Full upper bound*

Turning to the task of estimating the incremental cost of double register metering of residential customers, an example will serve to illustrate the procedure. From the Sangamo Electric Company we have obtained acquisition cost figures for the ordinary, or single register, KWH meter and for the double register meter which would be necessary if residential customers were to be charged different prices offpeak and on peak. The simpler meter could be acquired by utilities for $16.00 in 1972, and the double register meter for $57.58. But it would be incorrect to take these as capital cost figures, for the capital cost of a meter which is entered into a utility's rate base is the installed cost of the meter, and installation cost can be substantial and varies between companies. From Federal Power Commission From 1 we can reconstruct each system's installation costs by the simple expedient of deducting from the reported per meter increase in the rate base our known acquisition cost of $16. For example, for the Potomac Electric Power Company, 1972 installation cost computed thus is $56.51. Assuming that installation costs for the double rate register are no higher than those for the single rate register, we may add this installation cost figure to the acquisition cost figure for the double rate register, $57.58, in order to obtain a capital cost figure for double register metering, in this case $114.09. Of course, the single register figure, obtained directly from Form 1, is $72.51. By annualizing each of these capital cost figures--as above, we assume an 8 percent rate of return on original cost--we have annual capital cost figures for single and double rate registers. For operating and maintenance cost estimates, we have available the breakdown provided by Form 1 in which operating costs are decomposed into meter reading costs, meter maintenance costs, and a miscellaneous meter expenses category. The definition of meter expenses given in the Federal Power Commission's standard accounts is the obvious one; while meter expenses "shall include the cost of labor, materials and expenses used and incurred in the operation of customer meters and associated equipment," i.e., operating as opposed to maintenance expenses associated with metering, exclusive of meter reading expenses.

Since we have, for each system, the number of meters, each of these figures can be put on a per meter basis. For example, in 1972 the Potomac Electric Power Company reported per meter reading expenses of $2.11, per meter maintenance expenses of $.33, and per meter meter expenses of $1.65, or total per meter operating and maintenance expenses of $4.09. In our estimates of the corresponding figures for double register metering, we have somewhat naively assumed, for each system, the same numbers. This is certainly defensible for meter reading: the major expense is the labor and transportation cost involved in moving the reader between meters. For the remaining components of operating and maintenance cost, the assumption is not as persuasive, but we have no alternative. The cost differencial between single register and double register metering is then equal to the difference between annualized capital cost figures for the two modes of monitoring, and it is this differential that is entered as the column "Incremental Cost of Metering per Customer" in Table 42, Net Peak Period Residential Schedule Indicators of Improved Pricing. By multiplying that figure by the average number of customers served during 1972 under each residential rate schedule for each of our systems, and deducting the product from our previous estimates for these schedules in Tables 37 through 41--remember that there are two such figures, one for a price change which depresses peak consumption by 10 percent, and another for a price change in which our upper bounds are used as prices--we obtain the net benefit or indicator figures of the final two columns of Table 42.

Table 42. NET PEAK PERIOD RESIDENTIAL, SCHEDULE INDICATORS OF IMPROVED PRICING

System Rate Schedule	1 Ten Percent Peak Benefits -Gross Benefits ($)	2 Peak Upper Bound -Gross Benefits ($)	3 Average Number of Customers	4 Incre-mental Metering Cost per Customer ($)	5 Total Incremental Metering Cost ($)	6 Net Benefits I = 1 - 5 ($)	7 Net Benefits II = 2 - 5 ($)
POTOMAC ELECTRIC POWER COMPANY				4.48			
Residential	137,610	5,548,191	391,046		1,751,886	-1,614,276	3,796,305
COMMONWEALTH EDISON COMPANY				4.84			
Small Residential	156,775	10,251,715	1,003,359		4,856,257	-4,699,482	3,830,542
Large Residential	719,558	60,741,870	1,348,632		6,527,379	-5,807,821	54,214,491
Residential Space Heating	19,515	20,934	62,894		304,407	- 284,892	-9,473
DUKE POWER COMPANY				4.56			
Residential (R)	85,164	499,225	253,559		1,156,229	-1,071,065	-657,004
Residential (RS)	109,953	4,530,781	138,189		630,141	- 520,188	-13,906,640
Residential (RW)	235,165	13,161	488,754		2,228,718	-1,993,553	-2,215,557
Residential (WGS & MISC)	2,396	221,115	3,657		16,676		
NEW YORK ELECTRIC AND GAS				4.65			
Residential	169,635	1,027,309	525,616		2,444,114	-2,274,479	-1,416,805
PENNSYLVANIA POWER AND LIGHT				4.59			
Residential (RS)	206,429	2,839,302	674,736		3,097,038	-2,890,609	-257,736
Residential (RH)	65,457	4,468,587	69,486		318,940	- 253,453	4,149,647
Residential (SGS, AL & CS)	1,518	118,566	232		1,065	- 453	117,501

CATEGORY III INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Recall that customers in category III are assumed to have decided, on information cost grounds, to be marginal rather than average price sensitive; it is further assumed that they do not, or do not have the opportunity to, distinguish between offpeak and peak consumption. (The latter constraint might be assumed to arise institutionally.) This set of assumptions is, as we have argued above, probably most germane to the situation of large residential users; not because it is not potentially relevant to large commercial and industrial users, but because these later customers typically know their load curves, so that the assumption of unwillingness to differentiate between offpeak and peak consumption seems artificial.

A major difficulty surrounds the estimates of this section. For example, no company with which we are familiar knows the load curve of tailblock residential customers, i.e., those residential customers whose monthly bills put them in the final consumption block. Under the curcumstances, we believe that a sensible estimate of the potential benefits to be derived from futher investigation of load curves by block is as follows. Make the somewhat drastic assumption that all tailblock consumption occurs during peak hours. This, we hasten to point out, is not much different from what many utility personnel suspect: that much of peak growth attributable to residential consumption has, in recent years, been in the tailblock. Then an indicator of potential improvement can be computed by estimating the benefits accruing from an upwards adjustment of the tailboock rate towards the peak prices we have computed (and which are reported in columns 6 of Tables 32 through 36). For illustrative purposes, we have chosen a variety of "inversion" which many of the advocates of rate inversion have put forward, an inversion in which the height of the tailblock is raised to be equal to the height of the first block. Where one half of the derived upper bound is lower than the first block height, we use the former figure in this calculation.

Table 43, Category III Indicators of Potential Pricing Improvement, presents the results of these estimates. In column 1 of Table 43, we have entered the fraction of residential sales assumed to be tailblock sales, .1996. We have taken the same fraction for all systems only because we were able to get data for only one system, the Potomac Electric Power Company. In column 2 of Table 43 we have compiled estimates of peak KWH sales to residential customers by system and by season; these have been computed by the procedure set out in Table 26. Column 3 of Table 43, an estimate of peak tailblock sales, is then the product of columns 1 and 2. In column 4 of Table 43 we have compiled the relevant econometric estimates of price elasticity, the Chapman et. al. long run elasticity estimates. In column 5 of Table 43, we have recorded the height of the first block of each residential rate schedule in 1972, and in column 7 of Table 43 we have recorded the tailblock rate in effect, by system and season; in column 6 we have entered our upper bound estimate of appropriate peak price, from Tables 32 through 36. Generally, but not always, the tailblock rate is lower than the upper bound estimate of peak price and the first block rate lies between the two.

Accordingly, we compute a welfare gain estimate based upon whichever price is smaller, the difference between tailblock and first block, or the difference between tailblock and upper bound prices: that welfare estimate is what we could hope to gain by raising tailblock price by the smaller differential, assuming all tailblock consumption to be on peak. Column 10 of Table 43 is a compilation of those welfare estimates. A warning is appropriate in the interpretation of these figures: the reductions in peak consumption given by the usual elasticity formula are very large, sometimes amounting to total peak consumption. The source of this result is apparent: the application of our long run elasticity estimates to peak price changes often amounting to more than 90 percent of initial price. Accordingly, the benefit estimates are to be taken as order of magnitude estimates.

CATEGORY IV INDICATORS OF POTENTIAL PRICING IMPROVEMENT

Finally, recall that customers in category IV are assumed to be both marginal price responsive and to be able to distinguish, at no additional cost, between offpeak and peak consumption: this certainly would be the case for large commercial and industrial customers who already monitor their load curves, and of these there are many. Many of these customers are billed under tariffs which have block structures for both energy and demand charges, so that the customer's bill is computed from both energy and maximum demand readings. Thus, some additional procedures must be devised before proceeding to the estimation of indicators of potential pricing gain for this customer category.

Net Benefit Indicators for Demand Billed Accounts

The procedures we have employed above in order to derive indicators of the net benefits available from improved pricing cannot be directly applied to schedules with a demand charge component. The reason is somewhat obvious: when the consumer's bill depends in some complex way upon not only consumption but also upon maximum demand, the relationship be-

Table 43. CATEGORY III INDICATORS OF POTENTIAL PRICING IMPROVEMENT

	1	2	3	4	5	6	77	8	9	10
System Rate Schedule (Season)	Fraction of Sales Assumed in Tail-Block	Peak KWH in Season 10^3KWH	Peak Tail-Block Sales 10^3KWH	Estimate of State Average (and Marginal) Price Elasticities	1972 First Block Rate by Season $\frac{\$}{KWH}$	Upper Bound $\frac{\$}{KWH}$	1972 Tail-Block Rate by Season $\frac{\$}{KWH}$	Difference Between Tailblock Rate and Smaller of 6 or 7 $\frac{\$}{KWH}$	Fractional Price Change	Upper Bound on Efficiency Gains $\Delta W_{pk} = \frac{1}{2}\epsilon \Delta p KWH_{pk} \frac{\Delta p}{p}$
POTOMAC ELECTRIC POWER COMPANY										
Residential										
June-September	.1996	647,588	129,258	-1.22	.0375	.0796	.0205	.0170	-.5862	785,755
October-January	.1996	365,872	73,028	-1.22	.0375	.0796	.0135	.0240	-.9412	1,006,265
February-May	.1996	362,110	72,277	-1.22	.0375	.0796	.0135	.0240	-.9412	995,917
			Σ 274,563							Σ 2,787,926
COMMONWEALTH EDISON COMPANY										
Large Residential										
June-September	.1720	2,383,353	409,937	-1.21	.0386	.0578	.0226	.0160	-.5230	2,075,320
October-January	.1720	1,290,684	393,998	-1.21	.0386	.0578	.0226	.0160	-.5230	1,994,628
February-May	.1720	2,155,833	370,803	-1.21	.0386	.0578	.0226	.0160	-.5230	1,877,202
			Σ1,174,738							Σ 5,947,150
DUKE POWER COMPANY										
Residential (R)										
July-October	.1996	279,346	55,757	-1.18	.0390	.0680	.0140	.0250	-.9434	775,852
November-February	.1996	270,234	53,939	-1.18	.0390	.0635	.0140	.0250	-.9434	75750,557
March-June	.1996	225,059	44,922	-1.18	.0390	.0653	.0140	.0250	-.9434	625,086
			Σ 154,618							Σ 2,151,495
Residential (RA)										
July-October	.1996	578,645	115,498	-1.18	.0400	.0270	.0100	.0170	-.919	1,064,593
November-February	.1996	559,769	111,730	-1.18	.0400	.0266	.0100	.0166	-.907	992,497
March-June	.1996	466,193	93,052	-1.18	.0400	.0272	.0100	.0172	-.925	886,534
			Σ 320,280							Σ 2,943,624
Residential (RW)										
July-October	.1996	1,010,966	201,789	-1.18	.0390	.0409	.0140	.0250	-.9434	2,806,684
November-February	.1996	977,988	195,206	-1.18	.0390	.0401	.0140	.0250	-.9434	2,715,122
March-June	.1996	814,499	162,574	-1.18	.0390	.0413	.0140	.0250	-.9434	2,261,242
			Σ 559,569							Σ 7,783,048
Total All Residential			Σ1,034,467							Σ12,878,167
NEW YORK STATE ELECTRIC AND GAS										
Residential										
November-February	.1996	574,163	114,603	-1.24	.0501	.0659	.0164	.0337	-1.0135	2,426,798
March-June	.1996	471,407	94,093	-1.24	.0501	.0655	.0164	.0337	-1.0135	1,992,485
July-October	.1996	497,435	99,288	-1.24	.0501	.0655	.0164	.0337	-1.0135	2,102,558
			Σ 307,984							Σ 6,521,841
PENNSYLVANIA POWER AND LIGHT										
Residential										
November-February	.1996	724,801	144,670	-1.22	.0500	.0741	.0130	.0370	-1.175	3,822,236
March-June	.1996	568,600	113,493	-1.22	.0500	.0762	.0130	.0370	-1.175	2,998,528
July-October	.1996	582,447	116,256	-1.22	.0500	.0624	.0130	.0370	-1.175	3,071,526
			Σ 374,419							Σ 9,892,290

tween perceived price and average price is somewhat more elusive. For, with few exceptions, demand charges are based upon noncoincident demand--upon the customer's maximum demand, whenever that maximum demand may occur, and not upon coincident demand (the customer's demand at the time of the system peak). Our route around this dilemma is, and must be, different for the different utilities studies, largely because the nature of the data we have been able to assemble varies from company to company; valuable information would be needlessly sacrificed with a uniform methodology.

We are encouraged by the comparability of results between systems. The magnitude of the benefit measure indicator does not seem to vary widely between systems.

There are three kinds of data upon which an appraisal of the performance of demand billed rate structures can be based. (1) From some systems we have been able to obtain data which summarize, on a monthly basis, total KWH and total KW for demand billed accounts: for each rate schedule served under a tariff with both demand and energy charges, we therefore have, on a monthly basis, total KWH, total KW, and, typically the number of bills sent. (2) For one system we have been able to obtain something very unusual: for Commonwealth Edison of Illinois we have, for a large sample of major industrial users, individual customer load curves on an hourly integrated demand basis for the whole of one week in August. Since industrial loads exhibit relatively little seasonal variation, this is valuable information. (3) For most systems, we must work from our rough constructed load curves by customer class for each season.

Such is the variation in data availability across our sample. We turn to a more explicit description of methodologies employed in each case, of checks on the adequacy of assumptions and approximations, and finally to a discussion of the results. A reminder of our objective: our guiding question is how well does the existing pattern of demand charges and energy charges approximate cost at peak? Of interest is not only the absolute deviation of perceived price from (our best estimate of) cost at peak, but also the importance of that derivation--a measure of benefits to be had from narrowing the discrepancy. Because methods for treating the demand billed accounts must necessarily differ between systems, whereas the methods for computing indicators of potential pricing improvement are identical, we reserve our discussion of those indicators until after the various methodologies have been discussed.

<u>Imputation of a Mean Demand Bill Where Aggregate Demand and Energy Data are Available</u>--Suppose we have, as we do for the Potomac Electric Power Company, data on the total KWH, total KW and number of bills, for each demand billed account, by month for 1972. Total KWH means the sum of the KWH for which customers in each demand billed customer class are billed in each month; total KW means the sum of customer maximum demands for the corresponding customer class and month. These data are compiled in Table 44. A representative bill may then be imputed as follows: take the per customer average KWH and KW, and, using the rate schedule, price out the bill.

<u>Imputation of Mean Demand Bill Where Sample Data on Individual Demand-Billed Customers is Available</u>--Table 45, Load Curve for a Single Industrial Customer, Commonwealth Edison

Table 44. POTOMAC ELECTRIC POWER COMPANY, DEMAND BILLED ACCOUNTS FOR DISTRICT OF COLUMBIA, SELECTED MONTHS OF 1972

Rate Schedule	Month	Total KWH	Total KW	Number of Bills
Commercial	January	204,825,718	496,079.4	5,241
	April	193,396,901	500,531.7	5,329
	August	298,741,659	751,304.0	5,391
Industrial	January	118,316,350	280,948.6	129
	April	113,582,130	280,038.4	130
	August	181,845,708	395,610.2	131

Company, is included to show the type of data upon which this section builds, and to emphasize what we have said before--that it would cost almost nothing for many systems to begin billing in a time-dependent way, since they necessarily know the load curves of their major industrial customers. By examining the hourly-integrated load figures, we can find the hour and the day, during the week for which we have this information, of the individual customer's noncoincident peak. Thus, for the customer occupying premise 47044, the peak came at 8 p.m. of August 16. We have the size of this customer's noncoincident peak--21,816 KW--and, from Table 45, this customer's energy consumption for the week. By multiplying that latter figure by four, we obtain an estimate of the customer's monthly consumption. Thus we have, for each individual industrial premise in the sample, an estimate of energy taken and demand. The calculation of the actual energy and demand bills paid by the individual customers is then a simple matter of looking at the relevant rate schedule and pricing out the particular customer's energy and demand charges. (This amounts to evaluating the algebraic expressions in the row 4, column 3 entry of Table 27.) In summary,

Table 45. LOAD CURVE FOR A SINGLE INDUSTRIAL CUSTOMER, COMMONWEALTH EDISON COMPANY, 1972

(Hourly Integrated Demand)

Hour Ending	Aug 13	Aug 14	Aug 15	Aug 16	Aug 17	Aug 18	Aug 19
1 AM	702	14,094	9,882	9,936	6,426	9,666	2,754
2 AM	702	18,090	15,552	10,962	13,878	18,198	2,430
3 AM	756	11,556	16,362	11,448	9,666	12,420	972
4 AM	702	9,990	12,042	5,670	7,992	9,126	972
5 AM	702	18,684	15,714	12,690	16,524	17,442	864
6 AM	702	9,666	16,578	13,176	12,096	12,744	918
7 AM	702	10,692	11,826	11,340	5,076	16,956	918
8 AM	702	16,686	20,682	12,312	17,280	12,204	1,080
9 AM	756	16,470	16,578	11,664	21,114	7,506	1,026
10 AM	810	8,316	13,878	18,900	13,176	9,612	1,134
11 AM	865	19,872	13,716	17,496	5,616	7,830	1,404
12 AM	756	19,440	16,794	14,742	5,616	8,262	1,134
1 PM	648	13,824	16,470	19,008	5,022	5,454	918
2 PM	702	19,278	17,658	16,254	6,102	9,180	918
3 PM	702	18,522	16,632	11,340	6,750	6,048	918
4 PM	648	9,990	15,822	12,852	5,238	2,970	810
5 PM	648	15,822	13,122	17,334	12,906	2,322	756
6 PM	648	18,954	10,692	9,072	19,454	2,538	702
7 PM	648	12,582	11,880	16,092	17,766	3,240	756
8 PM	648	13,338	14,256	21,816	6,318	3,672	756
9 PM	702	18,630	20,250	14,688	5,130	3,240	810
10 PM	1,026	17,064	15,498	18,630	5,022	3,078	756
11 PM	1,836	19,656	20,466	20,358	3,726	2,646	756
12 PM	3,240	17,766	16,200	12,042	3,780	2,322	702
Total	20,953	368,982	368,550	339,822	231,714	188,676	25,164

for this case in which we have obtained individual customer data, we can compute energy and demand charges for each customer.

<u>Imputation of a Mean Demand Bill Where Only Federal Power Commission Data are Available</u>--Finally, in the case where all we have to go on are the reports all large systems must file with the Federal Power Commission (FPC Froms 1 and 12), a representative bill for demand billed schedules may be constructed as follows. First, recall that we have imputed (in the course of our reconstruction of cost structures) customer class load curves subject to various assumptions. We may, by dividing the individual rate schedule contribution to the system peak by the average number of customers and by the number of hours during the system peak, derive an estimate of individual customer demand. Similarly, an average energy per customer figure can be derived. Taking the resulting energy and demand combination as our representative bill for each rate structure, we may price out this mean bill--again, this amounts to evaluating the algebraic expression in the row 4, column 3 entry of Table 27--and proceed.

These representative bills have been constructed as guides to what might be called "perceived" prices at peak. The central fact about them is that, with few exceptions, all demand charges are based upon noncoincident demand--upon the customer's maximum demand, whenever it occurs. This is in principal unrelated to imposed capacity cost, and only makes sense to the extent that individual customer and system peak demand coincide. Do they? The question can only be answered by sample data on individual large use load curves. But the only such sample we have seen, the Commonwealth Edison data in Table 45 above, is not supportive of this inference. Another rationale for noncoincident demand billing is, of course, that if industrial demand is approxiamtely flat then it matters not where billing demand is measured, since maximum noncoincident and coincident peak demands necessarily coincide.

How then to move from these representative bills to our benefit assessments? The crucial comparison is, of course, between perceived price at system peak and our reconstruction of cost at system peak on a rate schedule basis. The cost estimate has already been done, and amounts to our upper bound column of Tables 33 through 37. The perceived price estimate remains to be computed. First, recall that in terms of our customer typology, customers are here assumed to be both marginal price responsive and time differentiating, i.e., of type IV. Thus the price we want is the perceived marginal price of a peak KWH. Since the rate schedules we are considering in this section are demand-billed, the marginal price must be the sum of an energy and a demand component. For the energy component, the obvious candidate is the actual marginal energy charge corresponding to the mean bill for each rate schedule--in effect, the height of the energy block in which the mean bill sits. For the demand charge, things are not so clear cut, for here the charge is levied upon a noncoincident maximum demand basis. We therefore assume, in constructing a measure of the perceived demand charge, that customers subject to a noncoincident demand charge spread that charge evenly over time: they assume that their monthly demand charge is incurred at a constant hourly rate. Summation of energy and demand components gives us, at last, the perceived peak period marginal prices compiled, for each system and each demand billed rate schedule, in column 2 of Table 46.

Given both perceived price and estimated marginal cost, the construction of new benefit indicators on a rate schedule

Table 46. INDICATORS OF POTENTIAL PRICING IMPROVEMENT, DEMAND-BILLED SCHEDULES

	1	2	3	4	5	6	7
System Rate Schedule (Season)	KWH_{pk} 10^3KWH	Perceived KWH Marginal Price During System Peak $\frac{\$}{KWH}$	Upper Bound $\frac{\$}{KWH}$	Δp_{pk}	$\frac{\Delta p_{pk}}{p} = \frac{(4)}{[(3)+(2)]/2}$ [a]	Estimate of State Average (and Marginal) Price Elasticities	Seasonal Upper Bound on Efficiency Gains = ΔW_{pk} = $\frac{1}{2}\epsilon \Delta p KWH_{pk} \frac{\Delta p}{p}$
POTOMAC ELECTRIC POWER COMPANY							
General Service (GS)							
June-September	1,268,353	.0151	.0216	.00650	.354	-1.46	2,131,621
October-January	716,594	.0145	.0250	.01050	.532	-1.46	2,919,815
February-May	709,222	.0145	.0235	.00900	.474	-1.46	2,207,172
Large Power Service							
June-September	279,009	.00859	.0178	.00921	.698	-1.93	1,730,847
October-January	279,009	.00844	.0212	.01276	.861	-1.93	2,957,993
February-May	279,009	.00844	.0210	.01166	.817	-1.93	2,553,178
	Σ 3,531,196						Σ14,500,626
COMMONWEALTH EDISON COMPANY							
Small Commerical and Industrial							
June-September	2,276,368	.0148	.0280	.0132	.617	-1.48	13,718,828
October-January	2,222,243	.0148	.0280	.0132	.617	-1.48	13,392,638
February-May	2,059,061	.0148	.0280	.0132	.617	-1.48	12,409,199
Large Commercial and Industrial							
June-September[b]	1,990,614	.0094	.0228	.0135	.841	-1.87	21,422,454
October-January[b]	1,943,283	.0094	.0228	.0135	.841	-1.87	20,913,235
February-May[b]	1,800,586	.0094	.0228	.0135	.841	-1.87	19,382,867
	Σ12,292,155						Σ101,239,221
DUKE POWER COMPANY							
General Service (G)							
July-October	891,246	.0121	.0205	.0084	.515	-1.13	2,178,306
November-February	862,173	.0121	.0202	.0081	.502	-1.13	1,980,697
March-June	718,045	.0121	.0208	.0087	.529	-1.13	1,867,074
General Service (GA)							
July-October	548,715	.0081	.0143	.0062	.554	-1.13	1,064,835
November-February	530,816	.0081	.0142	.0061	.547	-1.13	1,000,682
March-June	442,080	.0081	.0146	.0065	.573	-1.13	930,258
General Service (I)							
July-October	1,402,182	.0061	.0135	.0074	.755	-1.65	6,462,854
November-February	1,402,182	.0061	.0134	.0073	.749	-1.65	6,324,853
March-June	1,402,182	.0061	.0138	.0077	.774	-1.65	6,894,097
	Σ 8,199,621						Σ28,703,656

[a] *Circled numbers are column numbers; uncircled number is the digit 2.*

[b] *Data are averages from calculations from a sample of premises.*

Table 46 (Continued). INDICATORS OF POTENTIAL PRICING IMPROVEMENT, DEMAND-BILLED SCHEDULES

	1	2	3	4	5	6	7
System Rate Schedule (Season)	KWH_{pk} 10^3KWH	Perceived KWH Marginal Price During System Peak $\frac{\$}{KWH}$	Upper Bound $\frac{\$}{KWH}$	Δp_{pk}	$\frac{\Delta p_{pk}}{p} = \frac{(4)}{\frac{(3)+(2)}{2}}$	Estimate of State Average (and Marginal) Price Elasticities	Seasonal Upper Bound on Efficiency Gains = ΔW_{pk} = $\frac{1}{2}\epsilon\Delta p KWH_{pk}\frac{\Delta p}{p}$
NEW YORK STATE ELECTRIC AND GAS							
General Service (PSC108SC2)							
November-February	86,342	.0121	.0227	.0106	.6092	-1.65	459,969
March-June	71,023	.0121	.0229	.0108	.6171	-1.65	390,497
July-October	74,944	.0121	.0229	.0106	.6092	-1.65	399,248
General Service (PSC113SC2)							
November-February	147,458	.0240	.0333	.0093	.3246	-1.65	367,232
March-June	120,931	.0240	.0333	.0093	.3246	-1.65	301,167
July-October	127,991	.0240	.0333	.0093	.3246	-1.65	318,751
Large Light and Power (PSC113SC3)							
November-February	191,910	.0149	.0178	.0029	.1774	-1.89	93,271
March-June	191,910	.0149	.0181	.0032	.1939	-1.89	112,491
July-October	191,910	.0149	.0180	.0031	.1884	-1.89	105,884
Primary Light and Power (PSC108SC3)							
November-February	33,310	.0073	.0176	.0103	.8273	-1.89	268,145
March-June	33,310	.0073	.0179	.0106	.8413	-1.89	280,625
July-October	33,310	.0073	.0178	.0105	.8367	-1.89	276,457
	Σ 1,304,349						Σ 3,373,737
PENNSYLVANIA POWER AND LIGHT COMPANY							
General Service (SGS)							
November-February	116,606	.0328	.0597	.0269	.582	-1.46	1,332,126
March-June	91,447	.0328	.0617	.0289	.612	-1.46	1,178,758
July-October	93,709	.0328	.0489	.0161	.394	-1.46	433,762
Large General Service (LP-3)							
November-February	439,437	.0121	.0219	.0098	.577	-1.46	1,813,207
March-June	345,134	.0121	.0227	.0108	.621	-1.46	1,689,087
July-October	353,557	.0121	.0195	.0074	.468	-1.46	893,482
Large General Service (LP)							
November-February	44,302	.0102	.0219	.0117	.729	-1.93	364,635
March-June	44,302	.0102	.0225	.0123	.752	-1.93	395,429
July-October	44,302	.0102	.0196	.0094	.631	-1.93	253,573
Primary General Service (LP-4)							
November-February	160,438	.0085	.0210	.0125	.848	-1.93	1,641,113
March-June	160,438	.0085	.0216	.0131	.870	-1.93	1,764,504
July-October	160,438	.0085	.0187	.0102	.750	-1.93	1,184,388
High-Tension General Service (LP-5)							
November-February	81,890	.0066	.0211	.0145	1.047	-1.93	1,199,694
March-June	81,890	.0066	.0217	.0151	1.067	-1.93	1,273,202
July-October	81,890	.0066	.0188	.0122	.961	-1.93	926,486
High-Tension General Service (LP-6)							
November-February	188,779	.0057	.0209	.0152	1.143	-1.93	3,164,962
March-June	188,779	.0057	.0215	.0158	1.162	-1.93	3,344,583
July-October	188,779	.0057	.0186	.0129	1.062	-1.93	2,495,703
	Σ 2,866,077						Σ25,348,694

basis is straightforward, and is carried out in Table 46, Indicators of Potential Pricing Improvement, Demand-Billed Schedules. Again, as in the case of the Category III benefit estimates, a warning is appropriate in the interpretation of these figures. The reductions in peak consumption given by the usual elasticity formula are very large, sometimes amounting to total peak consumption. Here, as before, the source of this result is apparent: the application of long run elasticities to peak price changes often amounting to more than 90 percent of perceived price. Accordingly, the benefit estimates are to be taken as order of magnitude estimates.

SECTION V

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16. Abstracts Quantitative estimates of the internal cost savings to be derived from changes in the pricing of electric power are devised and evaluated. The econometric literature on electricity demand is surveyed, and elasticity values are selected which are parameters for the overall benefit measures. A method for using reported utility data to estimate the cost of delivered power--at the system peak and off the system, and for each customer class--is devised. Data on five electric utilities is used to make estimates of the potential benefits from improvements in the pricing of electric power, for each customer class in each system. The estimated potential benefits are sufficiently large to merit load curve studies by block for residential customers. Such studies are necessary preliminaries to a definitive assessment of the proposals for so called inversion.

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