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, than 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 in 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 cost 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 10^6KW	Largest Plant Running 10^6KW	Margin if Largest Running Plant Fails 10^6KW	
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 COST
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 include: 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 Commission: 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 place 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 X 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 definition: 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 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 actu fixed cost recovery per peak KWH to our Column 5 estimates 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 fir 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 ir cluded. 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 i 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 Transmis-sion Cost to Inter-change	Non-inter-change KWH as Fraction of Total KWH	Allocation of Total Fixed Transmis-sion Cost to Nonin-terchange
$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' Trans-mission Costs	Average Number of Residential Customers	Average Number of Low Voltage Commer-cial Customers	Average Number of Large Power Customers	Sum of Averages	Residen-tial Customers as Fraction	Allocation of Trans-mission to Residential	Commer-cial Customers as Fraction	Allocation of Trans-mission to Commercial	Indus-trial Customers as Fraction	Allocation of Trans-mission 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 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 cost 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	$647,588 \times 10^3$KWH	$1,268,353 \times 10^3$KWH	$279,009 \times 10^3$KWH	$211,002 \times 10^3$KWH	
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, fix costs of generation would have been recovered at the rate of \$.0429/KWH, which figure is obtained as (\$103,266,719/2,405, x 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 apportio 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 divided by the number of KWHs taken on peak by the correspon-ing customer class. The line of Table 25 labelled KWH to Schedules During Peak presents our estimate of individual cus-tomer 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 x 10^3KWH, recovery per KWH would have been \$.0255/KWH. The other bracketed figures are obtained similarly.

Our description of the procedures whereby Table 25 is obtain-ed 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)(2,465,952) =	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 out put 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 in creased 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, roughtly 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 σ(1) q(2) On Peak; Elasticity σ(2) q In Toto μ Maximum Demand	Cost Recovery Strategy: Energy	Capacity	Customer	Residual
Two-Part Tariff	M +			✓	✓
[M;ε]	$q\varepsilon$	✓	✓		
Fixed Energy Block Rates: No meter rent and no seasonal differential [B(j), ε(j)]	$\Sigma_1^{S-1}B(j)\varepsilon(j)$ + $(q-\Sigma_1^{S-1}B(j))\varepsilon(S)$ where $\Sigma_1^{S-1}B(j)\underline{<}q\underline{<}\Sigma_1^{S}B(j)$	✓	✓	✓	✓
Energy and Demand: [B(j);ε(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(l), 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 non-coincident 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 $\{W(1)\}$ the 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 provide by the various tariffs with the typology of customer response 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:

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

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 monopolies 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 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

Denominator / Numerator	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 change 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 margin 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 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 $/KWH	Lower Bound ("SRMC") $/KWH	Generation $/KWH	Transmission $/KWH	Distribution $/KWH	Upper Bound $/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.

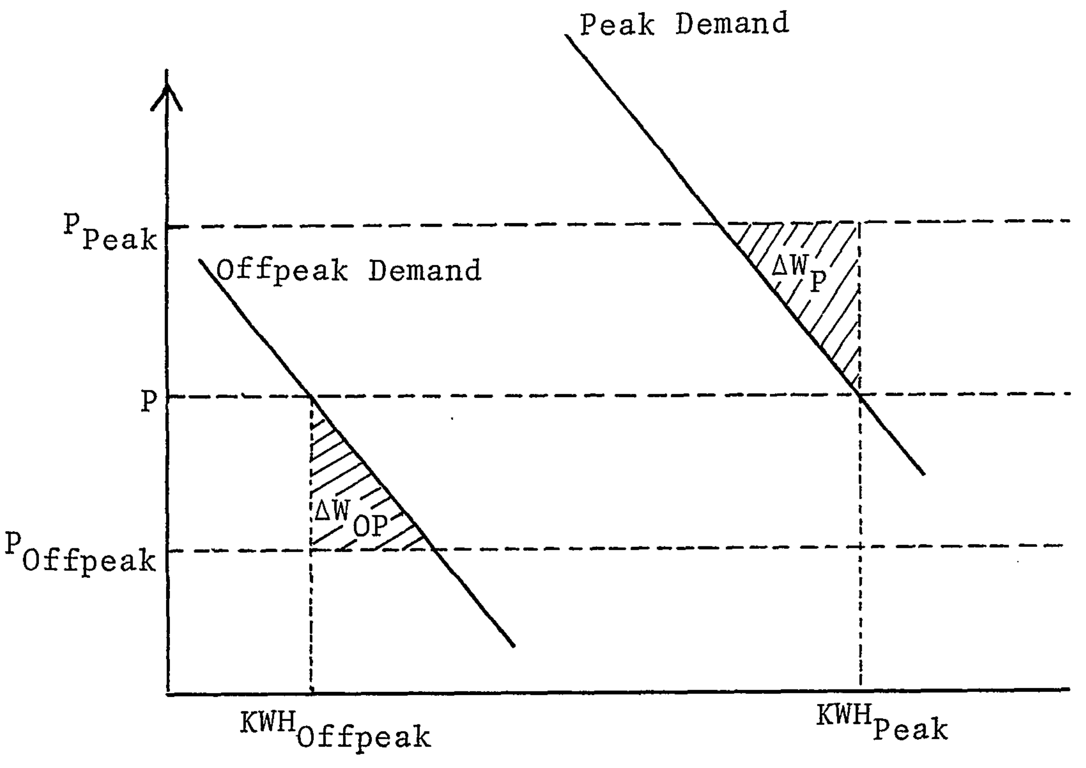

Figure 3. Welfare Gains from Peak Load Pricing

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'	$/\epsilon/$	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} $10^3 KWH$	$\Delta W_{op} = \frac{1}{2}\epsilon \Delta p KWH_{op} \frac{\Delta p}{p}$	Δp_{pk} 4-2	$\frac{\Delta p_{pk}}{p_f} = \frac{9}{4}$	KWH_{pk} $10^3 KWH$	$\Delta W_{pk} = \frac{1}{2}\epsilon \Delta p KWH_{pk} \frac{\Delta p}{p}$
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