New Approaches to Current Problems in Electric Utility Rate Design

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I. Introduction

The generation of electricity is usually accompanied by a variety of detrimental effects on the environment, including increased air, thermal and radiation pollution, use of increasingly scarce fuel resources, and degradation of land devoted to the siting of generating and transmission facilities. Environmentalists have argued that reduction in demand for electric energy is necessary to minimize these adverse environmental impacts.[1] They have also questioned the basic economic assumptions under which electric energy is sold by calling into review utility pricing mechanisms whereby the largest users are given quantity discounts. They contend that this practice induces greater consumption of electric energy and results in increased environmental harm.

Recently environmental groups have employed an additional, more successful argument to force regulatory commissions to review rate design practices. This argument is based on indications that the quantity discounts and other traditional rate design practices are no longer cost-justified and, therefore, should be abandoned. Needless to say, significant attention has been focused on the cost justifications for the total revenue and the corresponding charges to customers which a utility is permitted by the regulatory

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1. *See, e.g.*, Brief for Sierra Club and Students Hot on Conserving Kilowatts as Intervenors, Potomac Electric Power Co., Case 568 (Phase I), 95 P.U.R.3d 99 (D.C. Pub. Serv. Comm'n., May 9, 1972); Brief for Citizens for Clean Air, Inc., as Intervenor, Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973); Brief for Environmental Defense Fund as Intervenor, Niagara Mohawk Power Corp., Case 26402, 14 N.Y.P.S.C. 120 (Feb. 5, 1974).

commissions. However, a secondary focus on cost justification of rate design, *i.e.*, how the rate increases granted are to be apportioned among customers, has assumed unprecedented prominence in recent regulatory proceedings.

Challenges to traditional rate design practices have been launched by a broad-based alliance. In addition to the environmentalists, who are concerned with mitigating unnecessary growth, this alliance includes residential consumers who are concerned not only with increased bills but also with the allegation that they are subsidizing large commercial and industrial customers. Even some utility management personnel, under severe pressure to meet capital expansion needs at peak periods, while facing loss of earnings due to energy conservation measures, are advocating redesign of the rates.

Thus, widespread support has emerged in favor of revising the traditional "quantity discount" pricing practices. The substitution of "peak pricing" practices would serve to assess more accurately charges to residential and business customers according to the demands and costs which they impose on the system. Other rate design alterations flow from this proposed reorientation of electricity pricing, including methods to reevaluate costs among categories of customers and rates that will reflect estimated future incremental costs of generation.

This Article initially explores the historic economic justifications for traditional rate design practices and the changes within the electric utility industry which have undermined those justifications. It then examines the alterations in rate design which have been implemented by regulatory commissions throughout the country. Finally, the economics of rate redesign and some of its implications are analyzed through an examination of this new type of rate structure. At the very least, a new rate structure will produce rates more closely related to the costs of service. Viewed more broadly, however, rate redesign has the potential to curb pressure on utilities to expand their facilities, thereby significantly easing the burdens on the environment. In turn, as fewer, more costly plants are required, consumers will benefit by a reduction in the rate of increase in utility bills and a fairer allocation of costs among customers. Last but not least, utility managers will face less critical financing pressures.

II. A REEXAMINATION OF THE HISTORIC JUSTIFICATIONS FOR TRADITIONAL RATE DESIGN TECHNIQUES

A. *Pricing Within the Electric Utility Industry*

An electric utility provides service to its customers at rates which are regulated by the state public service commission in whose jurisdiction the utility operates. The commission establishes what it considers to be a fair overall rate of return on the invested capital which the utility employs in providing electricity to its customers. Based on this rate of return, the commission establishes the amount of gross revenue which may be earned to enable the utility to recoup the rate of return after operating expenses are met. Issues of rate design are primarily concerned with how the pie of base rate revenue responsibility is to be allocated among customers.

Pricing within the electric utility industry is complicated by the fact that the industry serves a public whose demands may vary throughout the day as well as throughout the year. Since electricity cannot be stored, a utility must design its generating system to meet maximum peak demand. The utility, therefore, constructs different kinds of plants to meet varying demand requirements. The first is the "base load" facility, generally a large (*i.e.*, 200 to 1,000 megawatts) fossil-fuel, hydro or nuclear unit intended to operate more or less steadily throughout the year except for periods of scheduled maintenance. Smaller, less capital-intensive "peaking" units are added, during certain periods in the day or in certain seasons of the year, to serve higher loads as customer demand increases to a maximum or "peak." These peaking units are often steam-powered electric units or gas turbines whose capacity may be in the vicinity of 100 megawatts (MW). They may be added in small increments to the "base load" facility to meet the total demand.

The base load equipment, while more capital-intensive, is generally more efficient than the peaking equipment in terms of operating costs (including those attributable to utilization of fuel resources). A unit's "heat rate" equals the quantity of fuel input in British Thermal Units (BTU's) required per kilowatt-hour (kwhr) generated. Thus, the lower the heat rate, the more efficient the unit. To illustrate, during the winter of 1971-72 on the

Consolidated Edison Company's system in New York City, the base load fossil-fuel units had an average heat rate of 10,300 BTU/kwhr. During the same period, the less efficient steam peaking units realized a higher average heat rate of 15,600 BTU/kwhr, whereas the gas turbine units averaged 14,800 BTU/kwhr.[2]

The pricing system which evolved within the industry to account for variations in costs of equipment utilization distinguished three elements of expense: (1) capital, or fixed costs; (2) operating expenses, or variable costs which do not include fuel costs; and (3) variable fuel costs. These expenses are reflected in the three types of charges paid by customers: (1) "demand" charges per kilowatt (kw) of capacity, which correspond to the capacity-related fixed charges of plant installed; (2) "energy" charges per kwhr, which correspond to the variable non-fuel component of operating expenses; and (3) "fuel adjustment clause" charges per kwhr, which cover variable fuel costs beyond the amount included in base rates. In addition, a minimum charge is made for "customer" services to cover the cost of billing and metering both energy and demand charge schedules.[3]

2. Testimony of Bertram Schwartz, Record at 1103-09 and Exhibit 132-A, Consol. Edison Co., Case 26292, 14 N.Y.P.S.C. 1213 (Aug. 19, 1974).

3. Base rates in the traditional pricing system are obtained in the following manner. First, the total energy charge component is calculated by adding the minimum charge for energy service to the price per kwhr multiplied by the quantity of kwhr. Then the minimum charge for demand service is added to the price per kw multiplied by the quantity of kw to achieve the total demand charge. The energy charge plus the demand charge equals the base rate. Then the fuel adjustment clause charge (*i.e.*, the price of fuel per kwhr multiplied by the quantity of kwhr) is added to the base rate to arrive at the overall charge. Thus:

$$TR_b = (C_e + P_eQ_e) + (C_d + P_dQ_d)$$
$$TR_f = (P_fQ_e)$$
$$TR = TR_b + TR_f$$

where,

TR_b = total revenues from base rates, *i.e.*, from demand and energy charges, excluding fuel adjustment clause charges.
TR_f = revenues from fuel adjustment clause charges.
TR = total company revenues.
C_e = customer costs or minimum charges for energy or kwhr service.
P_e = price of energy charges for kwhr provided.
Q_e = quantity of kwhr provided.
C_d = customer costs or minimum charges for demand or kw service.
P_d = price of demand charges for kw provided.
Q_d = quantity of kw provided.
P_f = price of fuel adjustment clause charges per kwhr provided.

Customers are typically grouped into service classifications according to their usage patterns. Generally, separate classifications exist for residential, commercial and industrial users. Customers in residential classifications normally pay only energy charges, while larger commercial and industrial users pay both demand and energy charges. All customers pay fuel adjustment clause charges.

Although electricity was originally sold at a uniform rate per kwhr, soon quantity discounts, whereby the price per kwhr declined as usage increased, were established as a means of encouraging consumption.[4] Until recent public service commission rulings, there were within virtually all service classifications on a typical electric utility system substantial quantity discounts for larger "blocks" (*i.e.*, ranges of usage) for both demand and energy charges. Thus, the more electricity consumed, the cheaper it cost per unit of demand, expressed in terms of kw, or per unit of energy, expressed in terms of kwhr. The fuel adjustment charges are not usually subject to quantity discounts and are "flat" or equal for all kwhr consumed.[5]

The practice of offering reduced block rates in the base rate structure was sustained by a classical economic theory which held that there were economies with respect to both short- and long-run production and distribution of electricity which should be reflected in reduced electric rates for increased consumption.

To understand the evolution of pricing within the industry, it is necessary to distinguish among three essentially separate notions of system economies within an electric utility system. First, there may be short-run decreasing costs due to the fact that once an investment in facilities is made, output can be increased with unit costs declining until the physical capacity of the facility is reached. Thus, the short-term variable cost phenomenon for which energy charges are established relates to fuller utilization of existing capacity.[6] For instance, once a 1,000 MW base load plant is built, variable as well as fixed costs per unit of output will be lowest

4. C.F. PHILLIPS, JR., THE ECONOMICS OF REGULATION 351 (1965).

5. *Id.* at 356 and n.6.

6. A. KAHN, THE ECONOMICS OF REGULATION, PRINCIPALS AND INSTITUTIONS 124 (1971). *See also* V. Smith, C. Cicchetti & W. Gillen, Electric Power Regulation, Externalities and the A-J-W Effect, a paper presented at the Seminar on Problems of Regulation and Public Utilities, Amos Tuck School of Business Administration, Dartmouth College, Aug. 26-30, 1973.

if the plant is operating at the maximum 1,000 MW level of output. If output were only 300 MW, then the cost for each unit would be 1/300 of total fixed and variable plant costs instead of 1/1,000 of the total costs (which would be the unit cost at capacity). Also, up to a point, variable costs per unit of output will probably decline as the number of workers and other variable inputs reach the level for which the operation was designed.[7] It should be noted that the short-run case assumes a fixed technology and a fixed time period, and is therefore a "static" phenomenon.

Quantity discounts for demand charges are partly sustained by the short-run decreasing cost phenomenon, but are bolstered by the second economic consideration of long-run decreasing costs. Here again a fixed technology and a given time period are assumed. If long-run economies are present, then the unit cost for a larger plant, if operated at its optimum (which is generally at its maximum rate), is less than the unit cost for a smaller plant, and economies of scale or increasing returns to scale are present. It has been asserted that the long-run decreasing cost phenomenon constitutes the primary justification for considering some public utility operations "natural monopolies."[8] In the literature of regulatory development, the efficiency with which one company could supply a market with larger, lower unit-cost plants was critical in justifying elimination of competition. Not only would facilities not be duplicated, but unit costs would be lower for the industry as a whole.[9]

A third economic consideration pertaining to the utility system is presented when a technological breakthrough occurs which lowers unit costs. Although this does not strictly fulfill the economist's notion of economies of scale, which assumes a given technological level, it nevertheless may result in "system-wide economies" by

7. KAHN, *supra* note 6, at 124.

8. *Id.*

9. Even if this unit cost structure were changed, there would still remain other reasons to continue large-scale monopoly operations. They include: (1) lower reserve capacity requirement per unit of system load (interconnections with other systems add to the reliability of service); (2) smaller total plant capacity per unit of customer demand because of the effect of diversity among the loads of large numbers of customers of various classes and businesses (large industrial loads are advantageous in this respect); (3) the ability to hold surplus capacity to a minimum when providing for increased loads; and (4) lower cost of supplies when purchased in large quantities. *See* R. CAYWOOD, ELECTRIC UTILITY RATE ECONOMIES 15 (1956).

shifting outwards the production function itself (*i.e.*, a greater MW output is obtained with the same unit cost).

The fuel adjustment clause was designed to allow the utility to recoup current increases in fuel expenses (or, in the case of a decline in fuel costs, to pass savings to customers) automatically, rather than having to wait for changes in tariff rates which require lengthy proceedings. Fuel costs above a base amount are charged to customers as they arise, allowing for accounting lags. For ease of computation, the total allowable fuel costs generally are divided monthly on a per kwhr basis. All customers are charged an equal or "flat" rate for each kwhr they use.

When fuel costs were an insignificant portion of a customer's bill, this practice seemed not only efficient but reasonably equitable; more precise calculations to reflect variations in BTU efficiency and fuel consumption during peak and off-peak periods would have yielded only insignificant alterations in rates paid. But in recent years, especially during the fuel shortages of the 1973-74 and 1974-75 winters, fuel costs have escalated rapidly, and a need has arisen to scrutinize the rate design of the fuel adjustment clause to systematically incorporate variations in fuel costs resulting from use at times when the system is more efficient or less efficient.

B. *Reevaluating Base Rates*

Throughout most of the history of electric utilities the three previously mentioned economic phenomena have occurred: short-run decreasing costs, long-run decreasing costs due to economies of scale, and system-wide economies due to new technological offerings. The pricing system which incorporated quantity discounts for large use, either in terms of capacity costs or demand charges or in terms of variable costs or energy charges, was appropriate. At the least, encouraging consumption to fill the excess capacity of the fixed plant would result in lower average unit costs for all customers. To the extent that such encouragement of consumption would raise demand so as to require additional facilities, this system would result in building larger, lower unit-cost plants and average costs would again decline. Recent evidence, however, indicates that while the first type of economy (short-run decreasing costs) may still pertain in certain, although more limited instances, the two latter types of economies (long-run decreasing costs due to economies of scale, and long-run decreasing costs due to system economies) appear to have been exhausted—at least for the present.[10] The quantity discount pricing mechanism which was designed to cover a three-fold decreasing cost situation appears to be outmoded. Pricing to reflect a more limited, short-run decreasing cost phenomenon may now conflict with pricing to reflect a long-run *increasing* cost phenomenon which has recently developed.

To a certain extent, increased usage of kwhr benefited the old system since idle plant was put to use and excess capacity was minimized. If usage were encouraged to the extent that it exceeded existing capacity and new plant was needed, no significant problem was posed as long as long-run costs were declining. However, when usage in off-peak periods (such as for electric heating) caused spillovers into peak periods, where there was no excess capacity, the system had to adjust by increasing capacity, which recently is no longer of the declining-cost variety. If the increased usage could be confined to off-peak periods when excess capacity exists, then energy charge quantity discounts could be justified to cover the short-run decreasing cost case. However, since quantity discounts may encourage usage to spill over into peak periods as well, a review of the promotional practice is in order.

The experience with light water nuclear power plants (LWR) from 1961 through 1975 is indicative of the significant cost trends within the industry, since most of the new generating units which have been added in recent years have been this type of unit rather than the traditional fossil-fuel plants. The bulk of the new generating capacity slated to be added in the near future, moreover, will be of the LWR-type, unless larger delays with the units and significantly more cancellations ensue. At the lower end of the size spectrum, as the size of the plant increases, cost per kw declines. For instance, two units under 100 MW in size cost over $450 per kw (in 1971 constant dollars), whereas plants in the 500-700 MW range cluster in the $100-200 per kw cost range. However, as a certain level of size is attained—somewhere over 500-600 MW—unit costs do not appear to fall significantly, if at all. Plants over 800 MW experience a $100-200 per kw cost similar to the smaller units.[11] It appears, therefore, that long-run decreasing costs due to

10. *See* text accompanying notes 46-119 *infra*.

11. Olds, *Nuclear Standards and Standard Nuclear Plants: More Than Money is at Stake*, 79 POWER ENG. 42, 44 (March, 1975).

economies of scale are lessening and that economies of scale are either exhausted, minimized, or obscured beyond a 500-600 MW range. Moreover, the average unit costs for all the LWR's going into commercial operation from 1971 through 1975 dramatically increase as size increases.[12] From 1971 to 1975, the per kw cost in constant dollars has accelerated more than 17% per year, in spite of the fact that the 1975 plants are 215 MW larger in average size than the 1971 units.[13] Thus, as one writer has put it, "[e]conomy of scale, if it exists, has been totally obscured by larger offsetting factors."[14]

The trend towards higher unit costs is apparent even when a mixed fossil-fuel and nuclear system is considered. For example, on the Consolidated Edison Company's system in New York City, the following unit costs were estimated:

TABLE I
CON EDISON CAPACITY COSTS
1969-1975

Facility	Year on Line	Total Estimated Cost $/kw (Current $)
Arthur Kill No. 3 (Fossil)	1969	$148
Indian Point No. 2 (Nuclear)	1973	208
Roseton No. 1 (Fossil)	1973	208
Bowline No. 2 (Fossil)	1974	218
Astoria No. 6 (Fossil)	1975	285
Indian Point No. 3 (Nuclear)	1975	433

Source: Brancato, *Con Edison's New Rate Structure: A Breakthrough in Electricity Pricing,* 1 N.Y. AFF. 76, 81 (Spring 1974).

Gas turbine peaking units were projected to be added at $200-240 per kw (current dollars) in the late 1970's; but, even removing the effects of price inflation, it is clear that the bulk of the company's new additions have significantly increased unit costs compared to formerly operating plants. Furthermore, the new plants will be replacing some older plants on the Con Edison system, such as those at Kent Avenue and Sherman Creek, which have lower imbedded costs per unit. This will raise still further the average unit costs.[15]

12. *Id.*
13. *Id.* at 44-45.
14. *Id.*
15. Brancato, *Con Edison's New Rate Structure: A Breakthrough in Electricity Pricing,* 1 N.Y. AFF. 76, 81 (Spring, 1974).

The trend to long-run increasing costs is expected to continue. LRW plants scheduled for completion in the early 1980's have 1975 projected costs of $750-800 per kw.[16] Furthermore, since costs for the technological innovation termed the liquid metal fast breeder reactor (LMFBR) can only be described as exorbitant, the advent of new technology is not likely to be much of a saving grace. The American Hallam and Fermi LMFBR's, the former just under 100 MW and the latter just over 100 MW, cost approximately $750 -1,200 per kw.[17] The European Phenix, with a cost estimated at $500 per kw, is approximately 250 MW in size, and a larger Phenix unit of 450 MW is estimated to cost nearly the same.[18] The Clinch River Breeder Reactor, the proposed first demonstration LMFBR in the United States with a commercial production date expected in the mid-1980's, may approach $2,500 per kw.[19]

C. *Changing Cost Factors in the Electric Utility Industry*

The conversion of the electric utility industry from a long-run decreasing cost industry into an essentially long-run increasing cost industry will create a marked deviation in its historic economic profile. A series of higher cost pressures have been exerted on the industry which have remained uncompensated by economies of scale or by technological improvements. Higher costs of new plants, beyond those merely due to increased inflation, have resulted from emerging trends in several important areas.

1. *Financing.* The electric utility industry has experienced a series of pressures which have hindered its ability to finance expansion. To begin with, it is a very capital-intensive industry. It has the highest investment per dollar of annual sales of any industry—$4.18, for example, as compared to $2.85 for the telephone industry.[20] While all industries have experienced severe inflation as they try to expand, the electric utility industry has been especially affected. Pressure on its basic capital-intensity status has been exacerbated as it has attempted to cope not only with inflation

16. Budwani, *Nuclear Power Plants: What it Takes to Get Them Built,* 79 POWER ENG. 38, 39 (June, 1975).

17. Olds, *supra* note 11, at 45.

18. *Id.*

19. *Id.*

20. U.S. FEDERAL POWER COMMISSION, TECHNICAL ADVISORY COMMITTEE ON FINANCE, THE FINANCIAL OUTLOOK FOR THE ELECTRIC POWER INDUSTRY, NATIONAL POWER SURVEY [hereinafter cited as FINANCIAL OUTLOOK] 51 (1974).

but with transition to a more highly capital-intensive nuclear technology. And while inflationary pressures have increased costs of production inputs such as labor, the costs of capital are rising more rapidly.

Pressure to expand plant facilities has come from the surge in demand for electricity due to increased use of electric services such as air conditioning and electric heating. Also, as electric rates were experiencing a long-term decline, industry replaced low-energy-use, high-labor-cost industrial processes with increasing automation. This has placed substantial demands on the electric utility industry to construct new facilities, which in turn are often the more capital-intensive nuclear units.

The rate of construction expenditures within the electric utility industry has increased from $3.6 billion per year in the 1950-54 period to $17.7 billion per year in the years between 1970 and 1974. And expenditures during the period 1975-79 are projected to be $27.5 billion per year.[21] This increase in turn has compelled the industry to raise more capital for expansion in the capital marketplace. During 1960-64, the industry financed 59% of all its construction funds internally and only 41% externally. By 1970-74, only 33% of construction money was internally generated, and 67% was obtained from external sources.[22] Because the industry is using more external financing, it is particularly exposed to the recent trend of increasing interest rates. In the early 1960's, interest rates for public utility bonds varied from 4-5%, whereas since 1970, the highest-rated triple A bonds have not sold for less than 7% and have at times approached the 9-10% range.[23]

Since the mid 1960's and especially since 1970, the rapid expansion of the electric utility industry's external financing, coupled with rising interest rates, has resulted in serious deterioration of electric utility company credit. In 1974 alone, credit ratings of 44 major investor-owned utilities were lowered while ratings for only 6 companies were increased.[24] The deratings have serious implications for the utilities' ability to float necessary bonds, since many purchasers of bonds, such as banks and investment accounts, require

21. *Id.* at 52.
22. *Id.* at 59.
23. *Financial News & Comment*, 95 PUB. UTIL. FORT. 37, 39 (Feb. 27, 1975).
24. FINANCIAL OUTLOOK, *supra* note 20, at 87-90.

minimum ratings. Also, it is not only the derated companies which are affected; an obvious "snowball effect" throughout the credit market may decrease availability of funds to all electric utility companies and drive interest rates up still further.

2. *Environmental Controls.* As federal, state and local governments require industry to install pollution control equipment, the social costs of environmental degradation are internalized. These costs are often cited as adding substantially to the increasing costs of the electric utility industry. The following tables detail investments made on 500-1,000 MW units for air quality control systems and for thermal discharge control systems during the mid-1970's period. They range in air quality control systems from $7 per kw for nitrous oxide (NO_x) combustion modification to a high of $60 per kw for the relatively infrequent process of limestone scrubbing to remove sulfur dioxide (SO_2). Investments made in thermal discharge control systems for fossil-fuel units vary from $3 to $28.90 per kw, and for nuclear units from $4.70 to $45.10 per kw. None of these costs includes the costs of monitoring and surveillance. In comparison to total cost per kw of capacity, certain pollution control devices do not add more than 5% to the basic cost of units, and only in certain cases where use is infrequent may pollution equipment contribute up to 30-40%.[25]

TABLE II

AIR QUALITY CONTROL SYSTEMS
RANGE OF INVESTMENT COSTS FOR NEW UNITS (500-1000 MW)

Control System	$/kw
Particulate Control	
Precipitators	$25 - 45
Venturi scrubbers	30 - 45
Bag filters	20 - 40
SO_2 control	
Limestone scrubbing	40 - 60
Lime scrubbing	35 - 55
NO_x control	
Combustion modification	1 - 7

25. Patterson, *Progress in Satisfying Environmental Requirements,* 94 PUB. UTIL. FORT. 13 (Aug. 1, 1974).

TABLE III

AIR QUALITY CONTROL SYSTEMS
INCREMENTAL ENERGY COSTS

Control System	Mills/kwhr
Particulate control	
Precipitators	0.7 - 1.2
Venturi scrubbers	1.0 - 1.3
Bag filters	0.9 - 1.6
SO_2 control	
Limestone scrubbing	1.5 - 2.2
Lime scrubbing	1.6 - 2.1
NO_x control	
Combustion modification	0.06 - 0.2

While important, the impact of environmental regulations should not be exaggerated. A large portion of the escalation in costs has been due, not to the environmentalists' insistence on a variety of emission controls and other safeguards, but to the utilities' difficulties in obtaining labor and materials and in making their new plants work. In its 1970 National Power Survey, the Federal Power Commission estimated that of a total of 114 steam-powered generating plants of 300 MW or greater which were projected to be put in use during the period from 1966 to 1970, only 31 units were on or ahead of schedule while 83 units were delayed. The Commission analyzed construction delays in the 28 nuclear plants which

TABLE IV

INCREMENTAL INVESTMENT AND ENERGY COSTS — FOSSIL

	Incremental Costs	
Thermal Discharge Control	Investment $/kw	Energy Mills/kwhr
Off-shore Subaqueous Discharge	$ 3.00	0.09
Cooling Pond	5.50	0.14
Cooling Tower		
Natural Draft Evap.	7.25	0.26
Mech. Draft Evap.	4.35	0.20
Parallel Path	5.60	0.26
Fan Assist Evap.	5.70	0.25
Mech. Draft Dry	28.90	1.21

TABLE V

INCREMENTAL INVESTMENT AND ENERGY COSTS — NUCLEAR

	Incremental Costs	
Thermal Discharge Control	Investment $/kw	Energy Mills/kwhr
Off-shore Subaqueous Discharge	$ 4.70	0.11
Cooling Pond	7.80	0.16
Cooling Tower		
Natural Draft Evap.	11.60	0.41
Mech. Draft Evap.	6.50	0.24
Parallel Path	8.75	0.31
Fan Assist Evap.	8.90	0.32
Mech. Draft Dry	45.10	1.61

Source (preceding four tables): Patterson, *Progress in Satisfying Environmental Requirements,* 94 PUB. UTIL. FORT. 13, 23-25 (Aug. 1, 1974).

were scheduled to become operational in 1974 and found that 32 plant/months of delay were attributable to public lawsuits or changes in regulatory requirements, but that 229 plant/months of work were lost because of low labor productivity, labor shortages, late deliveries of supplies, breakdowns of components, and similar technological failures.[26]

3. *Labor and Materials Shortages.* The rise in labor costs has been due not only to inflation but perhaps even more to a change in the variety of skills required to construct and maintain the more technologically complex nuclear units. While the problems of training workers should be short-term, they persist even though the construction of nuclear units began well over a decade ago. The longevity of the problem and the unlikelihood of a quick resolution make it appropriate to consider this issue as more than short-term

26. U.S. FEDERAL POWER COMMISSION, 1 NATIONAL POWER SURVEY ch. 16 (1970), *discussed in* Brancato, *supra* note 15, at 82. For a discussion of environmental consequences related to the siting of plants, such as "thermal discharges to waterways, injuries to aquatic life, and inroads upon scenic beauty resulting from the transmission lines made necessary by the remote locations of the plants," *see* Jones, *An Example of a Regulatory Alternative to Antitrust: New York Utility Regulation in the Early Seventies,* 73 COLUM. L. REV. 462, 527-28 (1973). In addition to increased costs due to environmental litigation surrounding the siting of many power plants, one must also consider that industries will choose the least expensive sites first; thus, a mature industry may be faced with less of a supply of available land, and that which is available may be of higher cost.

and to include its economic repercussions in current utility rate-making.[27]

While most industry experts believe utilities can in time solve anticipated skilled labor shortages, they are not as confident that the electric utility industry will be able to obtain the more technologically-sophisticated construction materials and equipment on schedule.[28] The anticipated resulting construction delays will contribute to an escalation of costs. If construction of a 1,000 MW plant is delayed six months, for example, the loss is estimated at $14,000,000 in interest costs in addition to the loss of working capital and sales revenue.[29]

4. *Availability of Constructed Plants.* Outages in plants give rise to a variety of costs, including direct costs of repair, costs of generating replacement power, and financing costs which endure even when a plant is "down." Many of the newer nuclear units have had high rates of unscheduled unavailability.[30] For instance, on the Consolidated Edison system in New York City, during the peak summer period in 1972, the company's nuclear unit had the highest

27. On April 15, 1974, the Atomic Energy Commission (now the Nuclear Regulatory Commission) issued an "Action Plan," in which it singled out for comment the shortage of nuclear-qualified welders, pipefitters and electricians. Many contractors were, in fact, recruiting welders and electricians in Canada to ease the shortage. Budwani, *supra* note 16, at 39. Last year, increasing lead times for structural steel components, carbon steel pipe and valves were reported. A number of foundries had been closed, exacerbating a critical shortage of casting supply. *Id.* at 40. Even in early 1975, steel allocations, particularly for heavier gauges and special shapes, continued to be troublesome, and problems still persist for specialty items such as steel castings for valves and pumps. *Id.*

28. Budwani, *supra* note 16, at 40.

29. U.S. OFFICE OF EMERGENCY PREPAREDNESS, THE POTENTIAL FOR ENERGY CONSERVATION 33 (1972).

A number of construction delays have been caused by a series of mishaps involving nuclear units. For example, Con Edison's Indian Point No. 2 has had an extraordinary series of problems. First, there were numerous difficulties in obtaining skilled labor. Then, in November 1971, a fire at the plant destroyed a great deal of the control instrumentation. Repair efforts lasted well into 1972. Brancato, *supra* note 15, at 82.

In the spring of 1972, Rochester Gas and Electric Co. discharged its Ginna reactor and discovered defects in the fuel rods, resulting from techniques used in their manufacture. Since the fuel rods for Indian Point No. 2 had been made using the same techniques and the same design, and welds in some of the smaller pipes proved defective in the summer of 1972, Con Edison decided to replace the fuel rods and undertake a major rewelding program. The plant finally came into service in the fall of 1973, but by December it was again shut down for repairs. *Id.* at 82-83.

30. A system's "unscheduled unavailability" measures the unanticipated unavailable capacity at the time of the daily system peak.

unavailability rate of all nuclear units in the country. In 1973, a Con Edison official testified that there were roughly 30 nuclear plants in operation in the United States and that, once on line, they have been available only 60% of the time. This is compared to fossil-fuel plants of similar size which were in service for more than 80% of the time.[31]

To compound this problem, nuclear units have design features which make them difficult to repair when they have trouble. Con Edison's president, Louis Roddis, Jr., in a 1972 address to the Atomic Industrial Forum,[32] noted that even at Indian Point No. 1, a plant that permits fairly easy access to repair components, a major repair is a "tortuous" event. For example, in May 1970, Con Edison detected the failure of a thermal sleeve in the reactor's coolant system. The total effort in locating the failure, analyzing its causes, designing the remedy and actually making the repair took seven months. It was estimated that the direct cost of repair was $1,000,000; the cost of generating replacement power was about the same.[33]

While some of the causes for the conversion of the electric utility industry from a long-run decreasing cost industry into a long-run increasing cost industry, for example, rising labor and construction costs, may appear to be due to the effects of inflation itself, there are specific changes in production inputs in order to incorporate more sophisticated nuclear technology which cause costs to rise faster than inflationary pressures alone would dictate. In addition, the persistence of some theoretically "short-run" trends, such as labor shortages over sustained periods, suggests that "short-term" may no longer describe a situation which may not be resolved for years to come and which, until that resolution, will be reflected in the current rates utilities are allowed to charge. Certainly, one would expect the availability of nuclear units to improve over time, as the technology matures and kinks are ironed out. Also, the present situation of relatively high interest rates and shortages of labor and materials may change. But it is apparent that, for the

31. Testimony of Bertram Schwartz, *supra* note 2, at 1176.

32. *See* Address by Louis Roddis, Jr., President of Consolidated Edison Co. of New York, before the Atomic Industrial Forum International Conference, Washington, D.C., Nov. 12-16, 1972, in Brief for Citizens for Clean Air, Inc., as Intervenor, *supra* note 1, at 6.

33. *Id.*

present, the cost structure of the industry has altered in a fundamental way. These developments indicate the need to review rate design to reflect these changes in rates, at least until such time as the situation alters again.

III. REDESIGNING ELECTRIC RATE STRUCTURES—A REVIEW OF DECISIONS BY PUBLIC UTILITY COMMISSIONS

Before the turn of the century, regulatory commissions established that quantity of consumption may constitute a legitimate and reasonable basis for discrimination in utility rates. Courts confirmed the legitimacy of this precept. In a New York case, *Silkman v. Board of Water Commissioners*,[34] the plaintiff had objected to the fact that persons who consumed large quantities of water were not charged as much per 100 cubic feet as those who consumed less. The New York Court of Appeals held:

> [I]t cannot be said to be unreasonable to provide less rates where a large amount of water is used than where a small quantity is consumed. That principle is usually present in all contracts or established rents of that character. It will be found in contracts and charges relating to electric lights, gas, private water companies, and the like, and is a business principle of general application.[35]

A similar position was expressed in 1930 by the Supreme Court of Errors of Connecticut. Although graduated rates per se were not at issue, the court, after noting that discrimination in rates is permissible if based on a reasonable classification, stated:

> Basing the charge of rate by a sliding scale upon the quantity used is an accepted principle of business administration as applied to public utility corporations, and this form of classification has been upheld by the courts where neither the classification nor the rates nor charges were unreasonable.[36]

The principle that discrimination in rates based upon the quantity of electricity used may be reasonable, and therefore lawful, was specifically upheld in a number of cases, including *Graver v. Edison*

34. 152 N.Y. 327, 46 N.E. 612 (1897).
35. *Id.* at 332, 46 N.E. at 613.
36. Bilton Machine Tool Co. v. United Illuminating Co., 110 Conn. 417, 426, 148 A. 337, 340 (1930).

Electric Illuminating Co.[37] and *Steinman v. Edison Electric Illuminating Co.*[38]

The practice of granting quantity discounts or reduced rates for increased kwhr use became common and today is generally embodied in statutory form. New York, for example, in Public Service Law sections 65 and 66, permits rate classifications based upon the quantity used, the purpose, the time or duration of use, "or upon any other reasonable consideration."[39] These sections specifically allow for "just and reasonable graduated rates."[40]

In the early 1970's, state regulatory commissions began to revise electric utility rate structures. They have rejected, to a varying degree, the earlier justifications for declining block rate structures and other traditional rate design techniques. This section details the redesigning of electric rate structures by the various electric utility commissions. The present redesigning of electric rates has been achieved through a loose-knit, cooperative effort by several environmental groups, such as the Center for Law and Social Policy in Washington (in conjunction with the Sierra Club), Citizens for Clean Air, Inc., the Environmental Defense Fund, and the Natural Resources Defense Council. As these environmental groups intervened in suits concerning the various utilities, the respective commissions began to bend in their approach to rate design.

Key decisions have been handed down with respect to the Potomac Electric Power Company,[41] Virginia Electric and Power Company,[42] the Consolidated Edison Company of New York,[43] Detroit Edison Company,[44] and Madison Gas and Electric Company.[45]

37. 126 App. Div. 371, 110 N.Y.S. 603 (Sup. Ct. 1908).

38. 43 Pa. Super. 77 (1910).

39. N.Y. PUB. SERV. LAW § 66(14) (McKinney 1955).

40. N.Y. PUB. SERV. LAW § 66(5) (McKinney 1955).

41. Potomac Electric Power Co., Case 568 (Phase I), 95 P.U.R.3d 99 (D.C. Pub. Serv. Comm'n., May 9, 1972); Potomac Electric Power Co., Case 568 (Phase II), 95 P.U.R.3d 118 (D.C. Pub. Serv. Comm'n., July 28, 1972).

42. Virginia Electric & Power Co., Case 19027, 95 P.U.R.3d 281 (Va. St. Corp. Comm'n., June 28, 1972); Virginia Electric & Power Co., Case 19342 (Va. St. Corp. Comm'n., June 17, 1974).

43. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. 630 (March 29, 1972); Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973); Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

44. Detroit Edison Co., Case U-4257, 2 P.U.R.4th 188 (Mich. Pub. Serv. Comm'n., Sept. 12, 1973) (interim rates); Detroit Edison Co., Case U-4257, 3 P.U.R.4th 209 (Mich. Pub. Serv. Comm'n., Jan. 4, 1974) (final rates).

45. Madison Gas & Electric Co., Case 2-U-7423, 5 P.U.R.4th 28 (Wis. Pub. Util. Comm'n., Aug. 8, 1974).

The commissions have made rulings ordering the flattening of declining block rate structures and the institution of summer/winter pricing differentials, a form of modified peak pricing. Certain commissions have also reevaluated the allocation of costs among service classifications, and among blocks within service classifications, in an effort to reflect more accurately the changing economic conditions within the industry. Finally, issues of energy conservation and environmental degradation, providing possible beneficial corollaries to instituting peak pricing based on long-run marginal costs, have been raised.

A. *Potomac Electric Power Company*

One of the first cases in which the declining block rate structure was challenged pertained to an application by the Potomac Electric Co. (Pepco) for an increase in its rate of return and an increase in rates for retail electric service.[46] In this case, the Sierra Club and Students Hot on Conserving Kilowatts (SHOCK) argued for a restructuring of electric rates. Their arguments focused on rate design and curbing the promotional activities in which Pepco was engaged, such as perpetuating a rate structure in which quantity discounts were given to the largest users. Central to the position of the environmental intervenors was the argument that all generation of electric energy is environmentally harmful, and that consumption of energy should be discouraged.[47] Sierra Club-SHOCK also argued that quantity discounts were no longer cost-justified.[48] The conclusion, therefore, was that, because the growth in the system had tended toward increased usage in the higher blocks, higher increases to higher use blocks were cost justified, since it is the higher use blocks which contribute to Pepco's need for new, more costly per-unit output plant additions.[49] The environmentalists

46. Potomac Electric Power Co., Case 568 (Phase I), 95 P.U.R.3d 99 (D.C. Pub. Serv. Comm'n., May 9, 1972).

47. *Id.* at 115; Potomac Electric Power Co. Case 568 (Phase II) 95 P.U.R.3d 118, 123; Brief for Sierra Club and Students Hot on Conserving Kilowatts as Intervenors, *supra* note 2, at 23-35, 58-61.

48. Brief for Sierra Club and Students Hot on Conserving Kilowatts as Intervenors, *supra* note 2, at 23-24, 58-61.

49. 95 P.U.R.3d at 124 (Phase I); Brief for Sierra Club and Students Hot on Conserving Kilowatts as Intervenors, *supra* note 2, at 23-24, 58-61.

called for a "neutral" rate schedule whereby kwhr charges would be equal regardless of quantity used.[50]

The District of Columbia Public Service Commission denied this request, stating that its judgment in this matter was influenced primarily by the fact that demand for electric energy at the retail level is price elastic: "[r]emaining unconvinced as we are with Pepco's costs and load factor, we are not disposed to accept [the environmental groups'] rate proposals or to prescribe at this time, on the basis of our own expertise, a wholly 'neutral' rate schedule."[51] But the Commission did order a significant change in rate design, structuring the rate increase so as to impose higher percentage increases on higher use blocks. The Commission stated:

> [A]lthough we recognize that there is testimony of record indicating that increased electric usage has been taking place over the past several years in all rate blocks, we are persuaded that the increase granted in this proceeding should recognize the fact that increased usage in the higher blocks should not result in disproportionate rate increases in the lower blocks of the residential rate schedules.[52]

Many of the positions advanced by the environmental intervenors were sustained by the Commission in a second case involving Pepco, two years later.[53] In this suit the Commission declared:

> We are persuaded by the evidence of record in this case that low usage consumers have not contributed to the need for the new investment and the new capacity required by Pepco in order to meet its public service obligations. We do not believe, therefore, that low usage customers should be required to bear the burden of significant rate increases. . . .
>
> We are also aware, as is Pepco, of the current energy crisis and the efforts being made by government and concerned citizens to conserve energy. We believe that we have an obligation to do what we can in this regard to assist and encourage Pepco and its customers to avoid unnecessary use, without penalizing essential uses of electric energy. We will therefore require that

50. 95 P.U.R.3d at 115 (Phase I), 123 (Phase II); Brief for Sierra Club and Students Hot on Conserving Kilowatts as Intervenors, *supra* note 2, at 61.

51. 95 P.U.R.3d at 126 (Phase II).

52. *Id.* at 124 (Phase II).

53. Potomac Electric Power Co., Case 596, 3 P.U.R.4th 65 (D.C. Pub. Serv. Comm'n., Nov. 16, 1973).

Pepco eliminate from its proposed rate schedules any increase on residential customers using 400 kilowatt-hours or less per month, and to transfer the revenue requirement that otherwise would be allocated to low usage residential customers to high usage rate blocks. We suggest, but do not require, that Pepco accommodate this transfer by eliminating the last rate block (over 800 kwh per month) of its proposed residential rate schedule.[54]

B. *Virginia Electric and Power Company*

An early case in which the electric utility company argued for redesigning electric rates involved the Virginia Electric and Power Company (Vepco).[55] In 1972, in response to a rate order which substantially cut a request for a rate increase, Vepco filed new rate schedules in which it created a new rate block at 600 kwhr for residential users priced at a higher rate in the summer than the preceding block. Vepco thus created a U-shaped rate structure by imposing a substantially greater increase on large users during the summer peak months than on the other users, while no increase was imposed on users in the preceding rate block (210-600 kwhr).[56] Schedule No. I for Residential Service prior to this ruling was:[57]

Monthly Rate for meter readings taken July through October

First 90 kwhr	@ 5.0¢ per kwhr
Next 120 kwhr	@ 2.5¢ per kwhr
Excess over 210 kwhr	@ 1.8¢ per kwhr

After the ruling, the following revised rates were in effect:[58]

Monthly Rate for meter readings taken July through October

First 90 kwhr	@ 5.490¢ per kwhr
Next 120 kwhr	@ 2.797¢ per kwhr
Next 390 kwhr	@ 1.787¢ per kwhr
Excess over 600 kwhr	@ 2.197¢ per kwhr

54. *Id.* at 79-80.

55. Virginia Electric & Power Co., Case 19027, 95 P.U.R.3d 281 (Va. St. Corp. Comm'n., June 28, 1972).

56. Address by R.H. Hallman, Eighty-fifth Annual Convention of the National Association of Regulatory Utility Commissioners, Seattle, Washington, September 20, 1973.

57. Virginia Electric & Power Co., Case No. 18759, 83 P.U.R.3d 417, Schedule I (Va. St. Corp. Comm'n., June 10, 1970).

58. Case 19027, 95 P.U.R.3d at Schedule I.

The U-shaped tariff not only alters the declining block rate structure but dictates imposition of a summer/winter rate differential whereby rates charged are higher in summer than in the winter.

In a subsequent Vepco rate case,[59] the Virginia State Corporation Commission approved rates which more firmly established the upward turn in the end-use block rates:[60]

Monthly Rate for billing months of July through October	
First 90 kwhr	@ 5.70¢ per kwhr
Next 120 kwhr	@ 2.90¢ per kwhr
Next 390 kwhr	@ 1.85¢ per kwhr
Excess over 600 kwhr	@ 2.60¢ per kwhr

Fairfax County intervened in this case and argued that large general service rates (*i.e.*, those normally accorded to commercial and industrial users) should be increased more than residential service rates, and that the Commission's ultimate goal should be to adopt a single rate for all rate blocks. To accomplish this, Fairfax County argued that any increase granted should be restricted to the upper rate blocks.[61]

The Commission accepted this argument in part by finding that Vepco should increase rates to large general service customers by a greater amount than for small general service customers. Residential customers did not receive a proportionately lower rate increase than large customers, however, since the Commission ruled that the rate increase should be assigned to the residential and large general service classes in proportion to the revenue they produced in prior periods.[62] According to the Commission:

> [M]any of the uses of electric energy which create high consumption are nonessential. Recognizing this, we believe that the revised residential rates should place more of the burden on the high-use customer.[63]

It is interesting to note that the rate design which emphasized the "U" shape and put higher increases on the last block, and which

59. Virginia Electric & Power Co., Case No. 19342 (Va. St. Corp. Comm'n., June 17, 1974).
60. *Id.* at Schedule I.
61. *Id.* at 8.
62. *Id.* at 38.
63. *Id.* at 39.

was approved by the Commission in the more recent Vepco case, was proposed by the company. Indeed, many utilities, after first fighting rate design which lessened quantity discounts for residential customers, now advocate them to lessen revenue erosion.

C. *Consolidated Edison Company of New York*

The Consolidated Edison Company of New York has itself advocated structuring rate increases so as to impose upon certain groups of highest use customers the highest percentage increases. A lessening of revenue erosion appeared to be the principal reason for these proposals.[64] As a staff witness on rate design for the New York State Public Service Commission has testified:

> Flattening rates help reduce revenue erosion due to increased energy consumption. Increased usage per customer over a period of time occurs in the lower priced end blocks resulting in lower average revenues per kwh. To the extent that the Company is experiencing increased usage per customer rather than increased numbers of customers, growth in revenues cannot keep pace with growth in sales which produces a continued erosion of net earnings. Therefore, greater increases in rates should be applied to blocks experiencing or expected to experience the greatest growth. If sales growth is not recognized, the result is revenue erosion and a continuing need for revenue relief. Higher usage blocks are contributing substantially to a need for new, more costly plant.[65]

In the 1972 *Consolidated Edison* case,[66] the Commission underscored the negative effect promotional aspects of stepped-down rates have on revenues. The Commission stated that

> the promotional aspect of stepped-down rates . . . is no longer valid, at least in the case of Con Edison. Confronted with an inability to expand capacity along economical lines, Con Edison

64. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. 630 (March 29, 1972).

65. Testimony of Cheryl Beach, Record at 2269, Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973). Regarding revenue erosion, *see also* Beach & Saffer, *Revenue Erosion and Electric Rate Increases*, 90 PUB. UTIL. FORT. 34 (Dec. 7, 1972); Epstein, *A Proposal to Modernize Electricity Tariffs*, 92 PUB. UTIL. FORT. 24 (Aug. 30, 1973); Address by Charles F. Luce, Chairman of the Board of Consolidated Edison Co. of New York, before FPC 50th Anniversary Ceremony, June 30, 1970, in Brief for Citizens for Clean Air, Inc., as Intervenor, *supra* note 1, at 14-15.

66. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. 630.

> is forced to meet increased loads by adding and running costly and inefficient gas turbines which use expensive fuel at relatively high heat rates; by retaining and operating an expensive and inefficient obsolete plant; by purchasing extraordinarily large amounts of power, at high cost, from other utilities; and by proceeding simultaneously with a number of expensive capital additions without any knowledge as to when any of them will become operational. It is clear that, except for load which is clearly off-peak or offers other specific economies, the result of the growing demand for electric power is to increase the average cost of service. In short, the incremental cost of increased volumes of electric power for many applications, and for the system as a whole, is in excess of the average cost of providing power to existing users: increased demands for power lead to disproportionately large increases in cost.[67]

The following year in the 1973 *Consolidated Edison* case,[68] the Commission questioned whether overall system-wide economies of scale exist, and held that stepped-down rates should be modified for Con Edison since incremental costs of new capacity and energy were exceeding average costs (*i.e.*, new plant was being added at higher unit costs).[69] Further, modifications in quantity discounts were ordered on the ground that increases in demand and the pressure to add new plant were coming primarily from increased consumption, mostly in the last blocks in the rate structure, by existing customers rather than from new customers. Thus, the Commission sought to correct the situation wherein the greatest demands were being placed on the system by customers paying the smallest block rate. These corrections imposed upon larger use blocks a higher percentage rate increase. This action was considered cost-justified, since the largest users were primarily responsible for increased growth in demand and thus responsible for the utility's need to build new, higher-unit cost plant.

In the first step of its analysis, the Commission noted that the demand for electric power on Con Edison's system was not attributable to any increase in the number of customers served by the company. Rather, the number of Con Edison's customers had been steady or declining; and, the Commission found increased demand for power, leading to increased costs and revenue erosion,

67. *Id.* at 654-55.
68. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973).
69. *Id.* at 1513, 1525-27.

was attributable to increased demand per customer.[70] The second step was to confirm this conclusion by the billing data analysis presented to the Commission in both the 1972 and 1973 *Consolidated Edison* cases. The breakdown presented in both cases showed kwhr sold in each block of consumption for several major service classifications, including residential, small commercial, and industrial and commercial redistribution (*i.e.*, master-metered office buildings where electricity is included in tenants' rent). The largest use blocks for SC-1, residential customers, increased 270% over the 1964-71 period while lesser use blocks had a growth of 103-143%. Small commercial and industrial customers experienced terminal block kwhr increases of 191% compared to 100-152% growth in lesser use blocks.[71] This data lent justification to the action requiring the largest use customers to contribute more towards the construction of new plant.

The 1972 and 1973 *Consolidated Edison* cases were significant for reasons other than the Commission's acceptance of the notion that higher use blocks were responsible for increased demand on the system. Most importantly, these were two of the earliest cases to delve into the economic structure of the utility's system and to determine in what manner this structure has changed. Within virtually all service classifications, until the 1973 *Consolidated Edison* case was decided, there had been substantial quantity discounts for large blocks of usage. This pricing scheme had been upheld by the Commission in prior cases, even though no cost of service studies to break down costs by block had existed. And, as long as the electric utility industry was experiencing annual reductions in cost and, therefore, in the price of electricity, the stepped-down rates which had been prevalent in the electric power industry almost since its conception remained valid.

> It has been generally considered that a stepped-down rate structure with lower unit charges for higher volume consumption was justified on the basis of economies involved in serving larger as against smaller customers. The larger volume of energy consumption was thought to improve the customer's load factor and achieve more economical use of transmission and distribution facilities. Further, service to larger customers

70. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. at 655.
71. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at Exhibit 149.

> was believed to result in economies of scale, since larger size conductors, transformers and other equipment cost less per unit of capacity than smaller facilities.[72]

The Commission noted that other justifications advanced for stepped-down rates were economies associated with growth in electric power production and, if overall volume can be increased, economies which will redound to the benefit of all the system's customers.[73]

However, in its initial finding that rates should be redesigned, the Commission determined that overall system-wide economies of scale no longer exist.[74] The Commission held that stepped-down rates should be modified for Con Edison since the incremental cost of new capacity exceeds average costs.[75] The Commission's decision in the 1972 *Consolidated Edison* case imposed a higher percentage rate increase upon larger use blocks, but noted that justifications for stepped-down rates which reflect improved load factor, and therefore economies in distribution and transmission, may still exist.[76] The following year, in the 1973 *Consolidated Edison* case, the Commission concluded

> there is no record evidence to support a finding that volume discounts are justified on the basis of economies of scale.[77]

To further its analysis, the Commission examined the record to determine whether improved load factors,[78] normally associated with volume usage, could justify a continuation of the stepped-down rate structure; it attempted to ascertain the cost responsibility based on load factor analysis to determine whether larger customers make more efficient use of plant. The Commission found that in several service classifications there is no correlation between larger users and high load factors.[79] Thus, the largest users would not utilize plant most efficiently, since they would not tend to require elec-

72. *Id.* at 1525-26.
73. *Id.* at 1526.
74. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. at 654.
75. *Id.* at 655.
76. *Id.* at 654.
77. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1526.
78. The most desirable load factor would be that associated with a customer who used electricity 24 hours per day.
79. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1529.

tricity around the clock; as a result, they should not be entitled to lower quantity discount rates.

Con Edison also presented evidence as to the contribution customers of various size made on capacity or demand responsibility. John Monsees, Director of Con Edison's rate department, testified in the 1973 *Consolidated Edison* case that the smallest customers impose less capacity or demand responsibility per kwhr of use than do larger customers. Coincidence factors (a measure of the tendency to exert demand at the same time as the system's operation peak) for classifications including most large use customers (SC-4, 8, 9) are generally in the 70-90% range. Coincidence factors for the larger users in the small residential customer class (SC-1), and in the small commercial and industrial customer class (SC-2), are in the 40-60% range; for the smallest SC-1 and SC-2 customers, coincidence factors fall between 25-30%.[80] Thus the smaller use service classifications and smaller use blocks within a given service classification tend to contribute less to peak demand than larger use service classifications and higher use blocks within a given service classification. Since unit costs of producing electricity increase with added capacity, and larger users contribute most to the need for such new capacity, the economic justification for affording quantity discounts to large users is seriously undermined.[81]

The Commission based its decision in the 1973 *Consolidated Edison* case on information indicating that the largest users did not make the most efficient use of existing plant, and that the largest use customers within service classifications and the largest use service classifications contribute most to peak demand and the need to build new higher-unit-cost plant. The Commission ordered the block structure of stepped-down rates to be replaced by a single energy charge for residential customers (SC-1) and small commercial and industrial customers (SC-2).[82] Other modifications to Con Edison's stepped-down rate structure included flattening out demand or capacity-related charges for multiple dwelling, sub-meter-

80. Testimony of John Monsees, Record at 3876, Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973).

81. Brancato, *supra* note 15, at 84.

82. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1528. A two-tier rate structure was later approved, imposing a rate increase of no more than 25% on highest use customers.

ing customers (SC-8) and instituting a two-step demand charge for larger commercial and industrial customers (SC-9).[83] The Com-

83. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1531. An example of the Commission's decision to level rates is the following:

ELECTRIC RATE
SC-2: SMALL COMMERCIAL AND INDUSTRIAL

Before Decision Case 26309		After Decision Case 26309	
First 10 kwhr	\$2.67 min. chg.	First 10 kwhr	\$4.00 min. chg.
Next 290 kwhr	5.554¢/kwhr	*All* over 10 kwhr	4.63¢/kwhr
Over 2,100 kwhr	3.609¢/kwhr		

(Source: Brancato, *supra* note 15, at 80.)

It is interesting to note that while in the 1972 *Consolidated Edison* case the Commission made recommendations to impose higher percentage increases on higher use blocks, in the 1973 *Consolidated Edison* case, the Commission chose the route of leveling the actual rates charged in each block. The difference between the two approaches illustrates one of the problems inherent in trying to reduce quantity discounts by applying higher percentage increases to higher use blocks. The Commission recognized that to apply increasingly greater percentage increases to end blocks may not change the actual tilt of the declining block rate structure. Indeed, depending on the mathematics involved, there may be an even wider spread between the first and last block under the percentage increase method than would be under equal absolute increases for each block or by leveling completely. The following table illustrates this fact:

SC-9: HIGH TENSION DEMAND CHARGES

	Rates in effect before Case 26309	Con Edison's Proposed % Increase in Case 26309	Absolute Increase	Con Edison's Proposed Final Rates in Case 26309
First 100 kw of maximum demand	\$5.13/kw	19.8%	\$1.02/kw	\$6.15/kw
Next 200	4.08	21.3	.87	4.95
Next 9,700	3.63	21.5	.78	4.41
Next 15,000	3.33	22.2	.74	4.07
Over 25,000	2.63	25.5	.67	3.30
Difference between first and last block	\$2.50/kw			\$2.85/kw

(Source: Brief for Citizens for Clean Air, Inc. as Intervenor, *supra* note 1, at 16.)

While the disparity for rates in effect before the 1973 *Consolidated Edison* case between the first and last blocks in SC-9 is \$2.50/kw, the disparity increases to mission also noted that in future cases it would consider making further adjustments to the rate structure of SC-9 if "the evidence continues to indicate a lack of correlation between size and group load factor."[84] While data indicated that the rate structure for another classification (the commercial redistribution classification) should be revised to lessen quantity discounts, the Commission held that substantial restructuring of rates in this category would result in unduly abrupt changes.[85] Finally, the Commission found insufficient data prevented the revision of rate structures for the other service classifications.[86]

Perhaps the most significant decision the Commission made in the 1973 *Consolidated Edison* case was to shift the burden of proof for justifying declining block rate structures to the utility companies. While the Commission did not eliminate rate differentials which it considered to be justified by cost considerations, it warned that in the future it will be incumbent on those advocating retention of rate differentials to demonstrate cost justification.[87] Thus, the Commission implicitly announced its intention to move toward rate redesign unless compelling evidence is presented to dissuade it from so doing.

In what we may refer to as the second phase of its opinions, the New York State Public Service Commission discussed in the 1975 *Consolidated Edison* case[88] how the theoretical model for rate de-

$2.85/kw by applying higher percentage increases to higher use blocks. Thus, by the order in the 1972 *Consolidated Edison* case to apply higher percentage increases to higher use blocks, rates in absolute terms can be made more promotional. It was not until the 1973 *Consolidated Edison* case that a true reduction in the promotional rate structure was affected by the PSC's ordering a leveling of rates.

It is also obvious that a reduction in the tilt of declining block rates would not be made if all blocks were to receive an equal absolute increase. For example, if in the example above all blocks were to be increased by $.87, the declining block structure would remain unchanged and the new rates would be:

minimum charge	$6.00
next 200 kw	4.95
next 9,700 kw	4.50
next 15,000 kw	4.20
next 25,000 kw	3.50

84. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1531-32.

85. *Id.* at 1529.

86. *Id.* at 1527-32.

87. *Id.* at 1534-35.

88. Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

sign must be adapted to incorporate changes in the economic structure of the industry; it determined that the whole model must be revised to replace historic costing with incremental costing in order to achieve a newer, more broadly-based concept of economic efficiency.[89]

The Commission reevaluated rate design predicated on the traditional cost model, according to which cost of service studies based on historic costs are devised and company costs are distributed on the basis of objective assignments, apportionments and allocations among the various classes of service. Use of historic costs was the long-standing Commission policy, and one that the Commission felt made obvious sense in terms of its responsibility to insure that rates are fair, reasonable, equitable and not unduly discriminatory. The Commission conceded that rates designed on the traditional model served the industry and the public interest only in periods of moderate inflation and when increases in the level of costs were more than offset by technological progress and the achievement of economies of scale. In its opinion, the Commission noted that these conditions no longer prevail generally and that "rates fashioned only on the traditional basis do not necessarily achieve such closely interrelated purposes as economic efficiency, environmental protection, and conservation."[90] The Commission set as its goal the achievement of a rate structure based upon principles of economic efficiency, which include requiring price to reflect externalities, such as environmental degradation, as well as those costs explicitly borne by supplying companies. Conservation, which discourages the wasteful consumption that occurs when prices are below cost, is now considered a necessary component of economic efficiency.[91] In short, there has been a marked shift in emphasis; a new rate structure, constructed in the interest of economic efficiency, has replaced one whose primary purpose was to effect a fair and equitable distribution of the total revenue requirements of a company.

The Commission's opinion in the 1975 *Consolidated Edison* case points out the most important differences between the two rate structures. First, economic efficiency will require that prices be

89. *Id.* at 478-81.
90. *Id.* at 479.
91. *Id.*

calculated on the basis of marginal or incremental costs. Second, the only measure of incremental cost that is pertinent is current or future costs; costs that have already been incurred can no longer be avoided even if incremental units are not purchased. Third, the value of the service component is minimized in favor of a stricter cost basis for setting rates. In designing rates to achieve a fair or equitable distribution of total costs, weight was given to the respective benefits that various users or classes of users derive from the system. Thus, such distributions and the rates that issued from them depended not only on cost but on value of service to the customer.[92] But the Commission ruled, instead of the old equitable rates which included a value of service component, the new, efficient rates should be based on marginal costs—not on what customers are willing or able to pay.[93] However, the Commission does advocate the use of value of service criteria to set rates when rates based exclusively on incremental costs yield companies either inadequate or excessive revenues.[94] This represents an important shift to a more future-oriented and more precisely cost-related rate design. Defining efficiency as at least theoretically encompassing environmental concerns and the cost to society at large of environmental degradation and natural resource depletion is a major addition to rate design theory.

The Commission noted that flattening rates, allocating capacity costs on the basis of peak responsibility, extending seasonal differentials, and introducing time differentiated pricing do not provide a complete solution to the problem of rate redesign. Nor do they necessarily produce optimally efficient rates, since in certain cases they may only approximate true incremental costs.[95] Nevertheless, the Commission considers them steps in the right direction and has ordered steps towards their implementation. To this end, the Commission has required quantity discounts to be eliminated, in most cases, except where customers attain superior load factors with their increased use and are, therefore, economically entitled to a reduced rate. In addition, to further the process of implementing new rate design techniques in New York, a new, generic rate procedure has

92. *Id.* at 480-81.
93. *Id.* at 481.
94. *Id.*
95. *Id.*

been initiated in which the theory and practicalities of rate design will be considered for all utilities in the State.[96]

D. *Detroit Edison Company*

The Michigan Public Service Commission has also reevaluated the changing technological state of the utility industry and its ramifications on declining block rate structures. In a 1974 case involving the Detroit Edison Company, the Commission stated in an interim order:

> The electric utility industry has until recently experienced a general downward trend in the cost of producing and supplying electric energy. The more kilowatt hours that were sold, the less they cost. . . . Large generating plants cost less per unit of output than did small generating plants. Technology was able to lower costs with each passing year. Transmission and distribution facilities to move the energy from the production plants to the customers were more fully utilized as more customers with greater usage began to use electric energy. The unit cost of supplying electric energy as a result dropped dramatically over the years. "Declining price" rate structures were a natural result of this phenomenon.[97]

The Commission took cognizance of the fact that the time-honored economics pertaining to the electric utility industry had changed:

> Today, things are different. Costs of building and operating an electric system have turned around. The incremental cost of producing the next unit is higher than the existing costs. Every additional unit of electric energy that must be provided will increase the overall cost of supplying energy.[98]

The Michigan Commission ruled that flatter rates for residential customers are in the public interest. Referring to a rate structure consisting of a monthly charge and a flat rate per kwhr, it observed that

> this form of rate structure for residential customers is realistic in terms of the cost to the utility of supplying electric energy. By raising the price in areas of consumption with high growth

96. *Id.* n.3; (this generic rate procedure is found in Consol. Edison Co., Case 26806 (N.Y.S. Pub. Serv. Comm'n.).

97. Detroit Edison Co., Case U-4257, 2 P.U.R.4th 188, 197 (Mich. Pub. Serv. Comm'n., Sept. 12, 1973) (interim rate).

98. *Id.*

rates, the incremental cost of additional demand on the electric system is more truly reflected in the revenues of the utility.[99]

While the Michigan Commission did not flatten residential rates altogether, it did make what it called a "fundamental move in the direction of 'flatter rates' ";[100] rates for the low usage customer were reduced by 3.5% to 5.7%, while the prices for the high use customer were increased by 2.7% to 5.4%. A distinction was drawn by the Commission between flattening rates for residential users and the need for a rate redesign pertaining to large commercial and industrial customers. No attempt was made to deviate from past rate design for the latter customers:

> Before the Commission can make changes in the structure of the commercial and industrial rate schedules, it must have facts to consider the impact of the changes on the economy of the state. The Commission would not like the cost of electrical utilities to be a disincentive to economic growth of Michigan or to result in the loss of jobs. The Commission will conduct special inquiries into this matter over the next year.[101]

In its final order,[102] the Michigan Commission reiterated its stance on rate redesign: for residential users, customers using 200 kwhr per month received an increase of 3.3%; whereas customers using 2,000 kwhr per month received an increase of 9.2%. In addition, the residential space heating rates were increased to raise the relative rate of return at the same time this class was changed to correspond with the revision in the residential schedule. The lower price applicable to over 1,000 kwhr per month on this rate schedule was eliminated for usage during the summer season so as to allow all residential customers with air conditioning equipment to be treated alike.[103]

E. *Madison Gas and Electric Company*

The Public Service Commission of Wisconsin, in a 1974 case involving the Madison Gas and Electric Company, found that a flat

99. *Id.* at 198.
100. *Id.*
101. *Id.* at 199.
102. Detroit Edison Co., Case U-4257, 3 P.U.R.4th 209, 249 (Mich. Pub. Serv. Comm'n., Jan. 4, 1974) (final rate).
103. *Id.* at 250.

rate design is reasonable, just, and a proper means of recovering energy and demand costs.[104] The actual changes made in rate structure substantially increase terminal block charges throughout the service classifications and impose in several service classifications a different set of rates for winter than those for summer, with summer rates having higher charges. With respect to residential rates, the Commission determined that the record did not justify the declining block structure proposed by the utility, and it ordered a flat residential rate with a winter/summer differential amount of 0.7¢ per kwhr for use over 1,000 kwhr.[105]

In addition, the Commission increased the minimum charge to more properly reflect total customer related costs. This had been an area of controversy within the case since the environmental intervenors had argued that more customer costs should be recovered in the minimum charge rather than having only partial customer costs so recovered and the remainder spread over the higher consumption blocks. The intervenors argued that spreading customer costs in this manner is inappropriate as a matter of economic logic and magnifies the differential between the initial blocks and the last block, fostering the belief that electricity is cheap when used in large amounts.[106]

The Wisconsin Commission also imposed a 33% increase on the terminal block for the commercial classification and made adjustments to shift the revenue responsibility from the energy to the demand charges (this was in keeping with the utility's long-run incremental cost study). The industrial rate classification received a demand charge increase in the terminal block of 60%. Moreover, a summer/winter differential was imposed for even the minimum kw of demand because of the very substantial number of commercial and industrial air conditioning customers which take service on these schedules.[107]

In addition to substantial rate design changes, the Wisconsin Commission, like the New York State Commission, shifted the burden to the utilities to prove the justification for a declining block rate structure.[108]

104. Madison Gas & Electric Co., Case 2-U-7423, 5 P.U.R.4th 28 (Wis. Pub. Util. Comm'n., Aug. 8, 1974).

105. *Id.* at 40.

106. *Id.* at 41.

107. *Id.* at 40-42.

108. *Id.* at 39.

The 1974 *Madison Gas & Electric* case is also significant for its treatment of long-run incremental costs (LRIC). The Environmental Defense Fund chose the 1974 *Madison Gas & Electric* case as a test case on electric rate design. The Environmental Defense Fund introduced evidence on the advisability and feasibility of employing LRIC as a basis for assigning electric utility rates.[109] In addition, Dr. Irwin Stelzer, a noted economist, appeared as a witness for the company; he too suggested that the economic principle of marginal cost pricing be adopted and implemented in the form of rates based on LRIC.[110]

The Commission, in its opinion, discussed LRIC, beginning with the observation that the marginal cost of an item

> refers to the change in cost that occurs with infinitesimally small changes in output. A central proposition of economic theory is that when prices of goods and services are set equal to their marginal costs of production, an optimum allocation of resources results. This occurs because the price will reflect the cost to society of producing one more unit of the good.[111]

The Commission further noted that the major obstacle in applying marginal cost pricing to electric utilities is measuring marginal cost.[112]

> Theoretically, the economically efficient price . . . is set at the short-run marginal cost (SRMC) of the smallest possible additional unit of sale. However, rather than short-run marginal cost, long-run incremental cost has been suggested as the logical surrogate for marginal cost. Long-run incremental cost is the incremental cost of the capacity and output which can reasonably be expected to be added in the next several years.[113]

The Commission discussed two reasons for looking to LRIC rather than SRMC. The first was practicality, since LRIC lends itself to measurement while SRMC does not. The second, and more basic reason, is the volatility of electric utility rates when tied to SRMC. Rapidly fluctuating rates would result, possibly depriving consumers

109. *Id.* at 34.
110. *Id.*
111. *Id.*
112. *Id.*
113. *Id.*

of those "expectations of reasonable continuity of rates" on which they must rely in making plans requiring the consumption of electricity.[114]

Madison Gas and Electric provided for the record estimates of the utility's LRIC. The LRIC study divided costs into the three components normally associated with fully distributed cost-of-service studies: (1) customer costs (meter reading, billing, etc.); (2) energy costs (that part of distribution costs which has been designated to cover operation and maintenance of existing plant, and which varies directly with the amount of kwhr consumed); and (3) demand costs (including generation and transmission capacity costs that vary with total kw of demand). In the LRIC study, the future costs of demand were estimated on the basis of anticipated expenses (adjusted to current prices) of additions to the utility's plant.[115]

The LRIC study was accepted by the parties and the Commission. The intervenors merely questioned specific issues relating to the estimates of LRIC. For instance, the treatment of inflation in the study was questioned, with several intervenors arguing that the estimated capacity costs, construction costs, and other utility costs should reflect expected future inflation. There was also some disagreement concerning the allocation of costs between customer and demand categories. Despite these reservations, the Commission concluded:

> We believe that the appropriate bench mark for the design of electric rates in the case is marginal cost as represented by the practical variant, long-run incremental cost. If electric rates are designed to promote an efficient allocation of resources, this is a logical starting point.[116]

The Wisconsin Commission further noted that

> [i]t must be understood that the long-run concept is pursued as the most appropriate and the most practicable cost measurement. The fact that "long-run" incremental cost is being used does not imply that the resulting rates will be valid for a long time into the future, nor that they will compensate for infla-

114. *Id.* at 34-35.
115. *Id.* at 35.
116. *Id.*

tionary cost increases. The primary objective that LRIC-based rates are intended to accomplish is to guarantee an efficient allocation of resources directed toward the production of electricity.[117]

Moreover, in a concurring opinion, the Chairman of the Commission, William F. Eich, remarked:

An electric rate design based on LRIC, then, will insure that those users placing the greatest demands on the system will pay the true costs of such usage–including the costs of new generating capacity. Such a design would give the proper "signals" to customers–that the more you use, the more costly it is to you and to society–and, to the extent that demand is elastic; it would have a desirable dampening effect on demand growth.[118]

IV. THE NEW ECONOMICS OF ELECTRIC UTILITY RATE DESIGN

As we have seen, the regulatory commissions discussed above have accepted, to a varying degree, the proposition that the electric utility industry has undergone fundamental economic changes. In response, they have ordered substantial changes in utility rate design. One of the most prominent alterations derives from the notion that the costs which are used to determine the rates charged customers should be based on a more future-oriented long-run incremental cost system rather than on an historic, fully distributed cost system wherein measured costs are those incurred in some previous period.

117. *Id.* at 35-36.

118. *Id.* at 45 (concurring opinion of William Eich, Chairman).

In other proceedings, economists, including Dick Netzer of New York University, William Vickery of Columbia University, Charles Olson of the University of Maryland, and Charles Cicchetti of the University of Wisconsin, have advocated pricing for utilities based on long-run incremental costs. Professor Vickery testified in the 1975 *Consolidated Edison* case that the concept of marginal pricing would insure that the cost of service is most precisely assigned to the recipients of that service. Testimony of William Vickery, Record at 9702, 9710-11, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

While existing cost allocation studies are based on historical customer usage data, a marginal cost pricing system would correlate future costs of additions to plant with customers whose additional or incremental demands are responsible for the need to expand the plant.

Substantial changes in rate design flow from this fundamental change in approach. For instance, the declining block nature of rate design whereby quantity discounts are given to large users must be reevaluated. So must the time periods during which costs are measured; peak pricing appears more necessary, as do seasonal differential rates. Finally, the allocation of costs among service classifications and among blocks within service classifications must be reviewed to remove existing biases towards the historical cost approach and accommodate the more up to date economic philosophy.

A. *Long-Run Incremental Costs and Pricing Systems: Inverted Rates, Flat Rates and Peak Pricing*

In a discussion of long-run incremental costs, it is useful to emphasize the distinction between short-run and long-run economics in the utility industry. In the short-run, when capacity is fixed, a pricing system which would encourage full utilization of capacity should be encouraged in order to spread the fixed costs over the largest possible number of users. Thus, there are so-called economies of scale in the short run for use which can be completely confined to off-peak times. The historic pricing system "tended to meet the requirements of both a short-run load factor improvement and long-run capacity expansion objectives."[119] Quantity discounts were justified on the basis of load factor improvement or fixed cost spreading in the short run. If the available capacity was not surpassed, greater spreading of fixed costs would result, tending to improve system load factors and reduce cost. However, with this approach a conflict arises when expansion in energy consumption occurs at the same time that expansion in peak demands occurs.[120] When the system's peak expands and energy consumption exceeds the available generating capacity, it becomes necessary to expand facilities. It is the long-run expansion of facilities and the need to build higher-cost plants, which increase average costs, that has created the principal concern in declining block pricing systems for electric utilities. Minimizing incremental capacity costs while, at the

119. Cicchetti, *Electric Price Regulation: Critical Crossroads or New Group Participation Sport*, 94 PUB. UTIL. FORT. 13, 14 (Aug. 29, 1974).
120. *Id.*

same time, improving the load factor are the dual objectives of electricity pricing. However, the fact that newly-installed increments in capacity are now being brought on line at significantly higher cost per kw than historic costs causes long-run and short-run objectives of electricity pricing to conflict.[121]

Several possible pricing systems could be derived using LRIC. The first uses "inverted rates," to price higher use blocks at higher rates than preceding blocks. The traditional quantity discount rate structure takes the opposite approach, pricing these blocks at the lowest rate. Where environmental intervenors in electric utility cases have proposed inverted block pricing, it has been rejected by most utility commissions as economically unsound.[122]

A second method of basing a pricing system on LRIC would be to institute a flat rate based upon an average of LRIC. The flat price (*i.e.*, a fixed flat rate per kw or kwhr) is easier to compute and implement, and represents a smaller deviation from the past. Some who propose flat tariffs have also suggested the adoption of a practice called "the inverse price elasticity rule,"[123] which means that LRIC would be the basis of pricing in each customer's category. If excess revenues result, prices would be reduced proportionately more for those users who are least likely to expand their consumption when confronted with the lower price. This means the less price-elastic the demand for a customer category, the greater the deviation between the flat price charged and the LRIC of supplying that customer class.[124]

However, neither the inverted rate pricing system nor the flat rate coupled with the inverse price elasticity system would be likely to assign costs in the most precise manner. While both of these pricing reforms may result in minimized capacity expansion by increasing costs to the largest users and thus discouraging consumption, they are both likely to detract from achieving the objective of spreading the fixed costs and therefore of improving load factor.[125]

121. *Id.*

122. *See, e.g.*, Consol. Edison Co., case 26105, 12 N.Y.P.S.C. 630 (March 29, 1972); Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973); Potomac Electric Power Co., Case 568 (Phase II), 95 P.U.R.3d 118 (D.C. Pub. Serv. Comm'n., July 28, 1972).

123. Testimony of William Vickery, Record at 9716, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

124. Cicchetti, *supra* note 119, at 15.

125. *Id.*

A third pricing system designed to take into account LRIC while establishing cost-related charges for customers responsible for the increased demands on the system has been proposed by Dick Netzer, Dean of the New York University Graduate School of Public Administration. This pricing system, which establishes differentials for peak and off-peak use, has been endorsed by the New York State Public Service Commission in the 1975 *Consolidated Edison* case.[126] Dean Netzer testified before the New York Commission:

> First, very modest rates of growth are in prospect for [Con Edison's] annual electricity sales, and if the present pattern of rates is continued and rates increase rapidly enough across-the-board, there will be virtually no growth in residential sales at all. Second, the system peak will continue to grow substantially, even in the face of the rate increases in prospect, if the present pattern of rate continues. Third, the result will be a continuous deterioration in load factor, with the prospect of even more rapid increases in rates across-the-board and/or financial disaster for the Company. This dismal cycle can be broken only by substantially revising the rate structure in the direction of sharply higher rates for peak demands. Such rates can help moderate the growth in peak demand, which can be accommodated only at sharply increasing costs per unit of service, and in any event will help recoup those costs, which should not fall on customers whose demand is not contributing to rising costs of service.[127]

For this reason, Netzer, stressing the crucial importance of implementing a more precise measurement of the use of power, urged that peak pricing with time-of-day metering be implemented within the Con Edison service territory. He further recommended that, while the company is changing to time-of-day meters, the Commission develop interim peak pricing rate revisions utilizing existing meters, including more comprehensive and more marked summer differentials.[128]

Use of peak pricing and time-of-day metering has several major advantages.[129] In the first place, it is a pricing system which makes possible a more precise measuring of consumption, which will en-

126. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 512-13. *See* text accompanying notes 88-96, *supra.*

127. Testimony of Dick Netzer, Record at 9916-17, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

128. *Id.* at 9917.

129. Testimony of Dick Netzer, *supra* note 127, at 9916-18; Testimony of William Vickery, *supra* note 123, at 9704, 9710-12.

able a more efficient allocation of resources.[130] In addition, a more accurate method of pricing will allow more accurate estimates as to which classes of customers place the highest demand on the system. This information in turn will facilitate more accurate projections as to how consumption patterns can be expected to change and develop among those classes and blocks over time. The New York State Public Service Commission, by its adoption of the existing summer and winter rate differential, and Con Edison, by its proposal to implement a demand ratchet[131] have indicated acceptance of the basic need for more precise measurement of electricity use.

A second advantage of peak pricing and time-of-day metering is that it will enable the company to respond, and even to some degree to control, emergencies and peak conditions. Con Edison now can only appeal to its customers to cut usage during emergencies. The imposition of a greatly increased price for continued use during emergencies would be an incentive toward reduction of such use.[132]

A third advantage could be a direct cost savings to the company in the form of fewer manual meter readings, since the new meters could be read by computer and existing meters might well be utilized as part of the operating machinery.

The final and perhaps most important advantage of peak pricing and time-of-day metering would be potential reduction in the need for the company to purchase and construct more expensive, environmentally degrading additions to plant in order to service peak needs.[133]

130. Testimony of William Vickery, *supra* note 123, at 9709-10.

131. *See* text accompanying notes 145-52 *infra*.

132. Testimony of William Vickery, *supra* note 123, at 9731-32.

133. *Id.* at 9729-32. According to the Federal Energy Administration, effective load management could reduce by one-third the 1985 industry-projected need for new plant capacity. The FEA's Office of Utilities Policy Development and Conservation Demonstration has six demand management programs underway with state and local agencies, including the Arizona Fuel and Energy Office which has a program for lower off-peak residential rates. The Arkansas Public Service Commission is monitoring load data for all classifications, including industrial customers, in response to new flattened rates, increases in summer/winter differentials and time-of-day pricing. Similar studies are being conducted by the Los Angeles Department of Water and Power, the Connecticut Public Utilities Commission, the New Jersey State Energy Office, the Central Vermont Public Service Co., the Green Mountain

With respect to the technical feasibility of time-of-day metering, testimony in the 1975 *Consolidated Edison* case indicated that fairly modern methods of time-of-day metering are in use in New Zealand, and have been in use in Europe for many years.[134] For example, in 1957, Electricité de France, the nationalized French utility, adopted its "green tariff," which was basically an industrial rate with charges bearing on the time of day and the season of the year.[135] "The rate levels were based on marginal costs, and when the tariff went into effect the utility estimated that it would result in a 5% reduction in use of electricity at peak. The projections were met, and in 1965 the concept was extended to residential rate classifications."[136]

The testimony indicated that the principal application of time-of-day metering for the immediate future should be for larger customers, rather than in the domestic market. Studies indicated that for certain large customers who now have recording demand meters, time-of-day metering could be implemented within a very short time period.[137] It was suggested that a system of voluntary time-of-day demand metering whereby a higher peak rate would

Power Company in Vermont and the Public Utility Commission of Ohio. N.Y. Times, Aug. 10, 1975, § 3, at 11. *See also* Bray, *Rate Test Affects Vermonters' Habits; Formula Could Reduce Woes of Utilities,* Wall Street J., April 1, 1975, at 38.

134. Testimony of William Vickery, *supra* note 123, at 9712-13. In France, customers have, in essence, a two-part rate in that the customer actually purchases a particular ampere load. For this load the customer pays a flat monthly charge. In addition, there is an energy charge for all consumption taken during the month; to control the amount of load which the customer actually takes, there is a circuit breaker set at the prescribed amount requested by the customer. This is, in effect, a load-limiting device, and there are administrative problems associated with it. The energy charged to the customer is the same whether he takes on-peak or off-peak use. Testimony of Gerald R. Browne, Record at 21-22, Massachusetts Electric Co., D.P.U. 18072 (Mass. Dep't Pub. Util., Sept. 1974). Browne also discussed a form of metering, which basically charges different rates for day and night use, and studies done in England with reference to domestic peak/off-peak pricing studies. *Id.* at 22-23.

135. Epstein, *supra* note 65, at 28-29. *See also* note 134 *supra.*

136. Madison Gas & Electric Co., Case 2-U-7423, 5 P.U.R.4th 28, 48 (Wis. Pub. Serv. Comm'n., Aug. 8, 1974) (concurring opinion of William Eich, Chairman). *See also* Clemens, *Marginal Cost Pricing: A Comparison of French and American Industrial Power Rates,* 40 LAND ECON. 389, 391 (1964); P. CALLE, *Marginal Cost Pricing and Random Future as Applied to the Tariff for Electrical Energy by the Electricité de France,* in ESSAYS ON PUBLIC UTILITY PRICING AND REGULATION 99 (1971).

137. Testimony of William Vickery, *supra* note 123, at 9760, 9814-15.

apply (customer use would be assumed to be on peak) unless a customer chose to install a peak/off-peak meter, in which case he would pay a set of rates established by the Commission which would, presumably, be lower by virtue of his having some off-peak use.[138] In this manner a phasing in of new meters could be accomplished with relative ease.

Even though present technology for such a meter is limited, utility companies' demand for them would create an incentive for their development. Technology could certainly respond to the possibility of a new, large market for these meters. At the present time experiments are being planned by the Philadelphia Electric Company based upon modification of existing meters, so as to introduce a time-of-day factor.[139]

The Public Service Commission of Wisconsin, in the 1974 *Madison Gas & Electric* case, took the following stand with respect to the development and cost of time-of-day meters:

> The cost associated with the installation and use of the equipment necessary to implement time-of-day metering is not known, nor was any evidence submitted on this point. Whether the im-

138. *Id.*

139. *Id.* at 9796-99. In response to interrogatories by the Environmental Defense Fund in June, 1974, a representative of Philadelphia Electric Company described the company's Automatic Meter Reading (AMR) research study. A pilot installation involving about 5,000 customers was scheduled for 1974 or early 1975. The system planned by the company would permit not only the reading of residential and commercial meters from a central point, but would have the added advantage of permitting the company, by sending appropriate signals, to disconnect loads such as water heaters, air conditioning compressors, and other contributors to peak loads. This would be done only by pre-arrangement with customers, possibly through rate differentials. This system would also permit the company to continuously monitor local voltage conditions, switch positions and transformer temperatures. In addition, the system could be shared with local water companies and gas companies. The total 1974 estimated cost of the project was slightly in excess of $1,600,000 for the cost of the 5,000 unit pilot. At that time, Philadelphia Electric expected that a substantial percentage of this amount would be shared by other utilities.

According to the interrogatories, the total anticipated cost of the AMR among all the company's residential customers is about $60,000,000. The company was asked the estimated realized savings per residential customer and per total cost of residential customers for each of the five years following the completion of installation. The response was that assuming a 7.5% inflation rate, the annual cost per meter of manual meter reading would be about $4.67 in 1978 ($3.50 per meter in 1974). Based on a financing charge of about 16%, this expense would justify capital investment of about $29 per customer or a total of $29,000,000. The company said the economic justification for installing the system, assuming its operational worth is established, will be dependent upon the value to the company of the additional benefits of load control and distribution system monitors.

provement in system-load factor warrants any additional outlay for metering depends on the elasticity of demand at various times of day. However, the recording-type metering equipment already in use for many commercial and industrial customers lends itself to time-of-day metering at a negligible cost. In this area an investigation into the possible benefits of such a pricing system should begin without delay. Such a pricing system could result in lower costs to the large users as well as an improved system-load factor for the utility.

The Applicant will be ordered herein to investigate the feasibility of such a pricing system. Since the results of such a study could have an important impact on all electric utilities in Wisconsin, we deem it desirable for several of the large private electric utilities to cooperate in such a study.[140]

B. *Summer/Winter Rate Differentials*

The process of determining how to distribute costs more fairly requires distinguishing between service not only on the basis of volume of electricity purchased but also on the times during the day and the year when electricity is used. Under this approach, customers are billed separately for day and night use and for summer and winter use. Customers would enjoy lower rates during off-peak periods; customers who confine their usage to off-peak times (regardless of the block which they fall into by virtue of the overall consumption) should pay less for their usage than those responsible for extra demands at peak times.[141]

As discussed above,[142] peak pricing has been used in Europe not only to determine daily peak and off-peak usage, but also to determine seasonal peak and off-peak usage. However, American utility companies have generally claimed that metering specified to charge differentially by the time of day would be inordinately expensive to install. In the absence of such metering, the principal way to refine allocation is to charge differentially for summer and winter use.

The New York State Public Service Commission approved summer/winter rate differentials in the 1973 *Long Island Lighting Co.* case.[143] The summer surcharge was deemed a necessary step toward

140. Madison Gas & Electric Co., Case 2-U-7423, 5 P.U.R.4th 28, 36-37 (Wis. Pub. Serv. Comm'n., Aug. 8, 1974).

141. Brancato, *supra* note 15, at 86.

142. *See* notes 134-35 and accompanying text *supra*.

143. Long Island Lighting Co., Cases 26283, 26284, 13 N.Y.P.S.C. 846 (May 19, 1973).

requiring customers using air conditioners to bear a higher portion of the costs their uneven demands placed upon the non-air-conditioning customers of this "summer peaking" company.[144] The Commission held that a summer/winter rate differential for summer peaking companies is desirable as a rate design concept, and has since extended its usage to other companies, such as Con Edison.[145]

In the 1973 *Consolidated Edison* case,[146] Con Edison presented evidence that in 1958 it had shifted from a winter peaking to a summer peaking company due to an extraordinary growth in air-conditioning demand. The summer peak had risen from 5,710 MW in 1965 to 7,872 MW in 1972.[147] Furthermore, the gap between the summer and winter peak demand had been increasing.[148] Arguments were made during the case that increased summer demand created the need to build new and higher-cost additions to plant. The widening gap between summer and winter peaks was reducing the overall system-wide efficiency and increasing average annual operating costs.[149] Moreover, testimony indicated that summer use imposed higher generation and transmission costs because equipment is less efficient in the summer. Hot summer days increase the need to cool steam generators, transformers and cables, and gas turbine capacity diminishes by about 20% in the summer.[150]

In its decision in the 1973 *Consolidated Edison* case, the New York Commission noted that the Con Edison billing system was inefficient, and that it could not cope with the administrative complexities of a special summer rate for customer categories with a large number of individual users. Therefore, the Commission, while recognizing that summer/winter differentials would be effective rate design tools for Con Edison, ordered that a summer/winter differential be applied in the amount of $.60 per kw only to a service classification in which there was a small number of customers. The Commission also stated that it would consider extend-

144. *Id.* at 860-61.

145. *E.g.*, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475, 489 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

146. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (N.Y.S. Pub. Serv. Comm'n., Sept. 6, 1973).

147. Testimony of John Monsees, *supra* note 80, at 706-07.

148. *Id.* at 3882.

149. Brancato, *supra* note 15, at 87; Testimony of Cheryl Beach, *supra* note 65, at 2262.

150. Testimony of John Monsees, *supra* note 80, at 3873.

ing seasonal rates to other classifications.[151] Indeed, in the 1975 *Consolidated Edison* case[152] Con Edison requested and the Commission approved significantly more widespread use of seasonal rate differentials in the residential classification, in the small commercial classification and in the residential space heating classification, contingent upon the company's ability to overcome problems in billing.[153]

Electric companies in other jurisdictions have also made use of the summer/winter differential to improve the system load factor. Missouri, for example, has had summer/winter rate differentials since the late 1950's.[154] The North Carolina Utilities Commission approved the use of summer/winter differentials for one company in 1971, noting that they were just and reasonable, and that "more than twenty electric utilities operating in other parts of the nation have rate schedules that incorporate seasonal differentials."[155] The District of Columbia Public Service Commission approved a seasonal differential in 1970, saying:

> The record in this proceeding demonstrates that the Company must have additional revenue to meet the financial requirements imposed by the growth in demand being experienced by the Company and its consequent necessity for increased capacity. The increase in capacity is substantially related to the growth in peak demand. This peak occurs in the summer period and unquestionably is related to the heavy use of air conditioning in Pepco's [Potomac Electric Power Co.] service area. We believe that the added costs involved in meeting this peak demand can legitimately be recognized by the charging of higher rates for higher levels of summer usage.[156]

The Public Service Commission of Wisconsin has dealt with peak load pricing, stating that a fully implemented application of LRIC pricing would have to be reflected in price differentials for on-

151. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1522-24. The service classification was that for multiple dwellings in which electric charges are included in tenants' rents (SC-8).

152. Consol. Edison Co., Case 26538, 8 P.U.R.4th 475.

153. *Id.* at 494-95, 501-03, 506.

154. Union Electric Co., Case 17433 at 12 (Mo. Pub. Serv. Comm'n., Nov. 17, 1972).

155. Virginia Electric & Power Co., Case E-22, 88 P.U.R.3d 261, 265 (N.C. Util. Comm'n., April 29, 1971).

156. Potomac Electric Power Co., Case 541, 84 P.U.R.3d 250, 254 (D.C. Pub. Serv. Comm'n., June 29, 1970).

and off-peak sales.[157] The Commission stated that a first approximation to such peak load pricing is the summer/winter differential which had been proposed by the Madison Gas and Electric Co. This differential was deemed to reflect the costs of a seasonably peaking electric utility better than a year round rate. The Wisconsin Commission stated, however, that full peak load pricing applied to electric rates must take the form of time-of-day metering.

> Under such a plan, rates would vary with the time of day in order to reflect the true cost of peak demand. Customers are compelled to pay for the actual cost they are imposing on society and are rewarded for shifting consumption to an off-peak time, thereby improving the utility's load factor. The winter/summer differential does not offer such an alternative. Summer air-conditioning cannot be postponed until winter.[158]

C. *Demand Ratchets*

A demand ratchet is a form of rate design whereby customers are billed throughout the year on the basis of their maximum annual demand or their maximum demands during the peak capacity season. A customer pays a rate for his maximum peak demand and then is charged a monthly demand rate which is a fixed percentage of his annual or seasonal peak demand. If the original peak is exceeded, that new peak becomes the basis for charging the customer.

It has been argued that demand ratchets more fairly charge customers for their share of the company's generation and distribution costs and tend to reduce customers' demand fluctuations. As one authority has testified:

> Ratchets force customers to pay some portion of the fixed costs on plant required to meet peak demands whether or not a customer uses his peak demand all year round. In effect, ratchets increase demand charges to customers whose demands vary extensively from month to month . . . . The Company must pay interest on money borrowed and the depreciation expense for plant needed to meet peak demands. Interest and depreciation are annual expenses to be paid whether or not the plant is used.[159]

157. Madison Gas & Electric Co., Case 2-U-7423, 5 P.U.R.4th 28, 36 (Wis. Pub. Serv. Comm'n., Aug. 8, 1974).

158. *Id.*

159. Testimony of Cheryl Beach, *supra* note 65, at 2277.

Proponents for demand ratchets claim that a customer's contribution to generation and transmission costs is most nearly approximated by his maximum annual demand. Five major New York State utilities (Central Hudson, Long Island Lighting, New York State Gas and Electric, Niagara Mohawk, and Orange and Rockland) make general use of demand ratchets.[160] The Commonwealth of Virginia State Corporation Commission approved a 90% ratchet for Virginia Electric and Power Co. in July, 1974.[161] The Commission found that the Company had shown that the impact of summer peak loads determines the capital investment required to meet off-peak demands, that these facilities can then be used in off-peak periods without further investment, and that the ratchet clause permitted the Company to recover higher costs associated with providing service to those customers with a summer peak.[162]

In the 1973 *Consolidated Edison* case,[163] the New York Commission found that it had not been established that demand ratchets were either a feasible or desirable rate design technique for Con Edison, but ordered studies to be performed and presented in the company's next rate case.[164]

The next case was the 1975 *Consolidated Edison* case discussed previously.[165] Here Con Edison presented a demand ratchet study. On the basis of that study, it advocated a 100% summer demand ratchet in the commercial redistribution (SC-4), multiple dwelling space heating (SC-12), and large commercial and industrial (SC-9) classifications. Con Edison testified: "[d]emand costs are more nearly annual rather than monthly costs since they are essentially the carrying charges on plant installed to meet the maximum demands of the customers on the various portions of the electrical system." Monthly demands were not reputed to be a good measure of customers' cost contribution since customers may "escape being charged for some of the demand costs which they create," and especially

160. *Id.* at 3445.

161. Virginia Electric & Power Co., Case No. 19342 (Va. St. Corp. Comm'n., June 17, 1974).

162. *Id.* at 39-40.

163. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491. *See* text accompanying notes 66-87 *supra*.

164. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491.

165. Consol. Edison Co., Case 26538, 8 P.U.R.4th 475. *See* text accompanying notes 88-96 *supra*.

"if a customer's greatest monthly maximum demand is coincident with the system peak demand."[166]

Con Edison's proposal would have established a pricing scheme according to which customers would pay demand charges every month equal to the highest summer demand charges, regardless of when during the day their actual peak demands occurred. Con Edison's demand ratchet proposal was opposed by the Attorney General of the State of New York on the basis that the use of demand ratchets would only approximate the peak contribution that customers make to the system, and would be less precise calculations than time-of-day metering. For example, should a customer's maximum demand actually occur in a summer off-peak period, billing throughout the year would assume that his demand was on-peak. Furthermore, there would be no direct incentive to reduce maximum demands at the system peak, but only an incentive to reduce individual maximum demands, regardless of when they occur.[167] The Commission recognized the disadvantage of instituting a demand ratchet as compared to the more precise peak pricing method, but ruled that a ratchet would represent a desirable intermediate step and would be preferable to the present structure. However, more study was considered necessary before implementation.[168]

D. *Allocation of Costs Among Service Classifications*

Another important aspect of recent changes in rate structure concerns the manner in which the overall revenue increase is distributed among service classifications. Most utilities have relied on general economic judgments with respect to the allocation of revenues among service classifications. It is only recently that cost of service studies have been employed in a precise manner to justify which rate classes should receive a greater or lesser percentage of any rate increase.

For example, the New York State Public Service Commission, in

166. Testimony of John Monsees, Record at 9295, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

167. Testimony of Dick Netzer, *supra* note 127, at 9928-29; Testimony of William Vickery, *supra* note 123, at 9704, 9727-29; Testimony of Carolyn Brancato, Record at 10129-30, 10151, Consol. Edison Co., Case 26538, 8 P.U.R.4th 475 (N.Y.S. Pub. Serv. Comm'n., April 28, 1975).

168. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 498-99.

the 1972 *Consolidated Edison* case,[169] approved an increase in revenues applied among service classifications in such a way that each class received about the same percentage increase; this had the effect of keeping unaltered the relationship between the service classifications. However, in the 1973 *Consolidated Edison* case,[170] the Commission scrutinized the basic relationships between classifications. Con Edison and the Commission staff presented cost of service studies which apportioned the three principal types of costs—energy costs, demand costs, and customer costs—among service classifications.[171]

Two areas of controversy have arisen concerning rate-making practices and cost of service studies. The first is the question of how valuable the cost of service study is in determining rates for individual service classifications; the second questions the proper method of allocating costs among service classifications.

1. *Proper Use of Service Classifications to Determine Rates.* A major controversy surrounding the use of cost of service studies involves the extent to which they can be used to determine revenue requirements. Testifying as an expert witness on behalf of New York City in the 1973 *Consolidated Edison* case,[172] Professor Charles Olson stated that the revenue requirement should be apportioned to service classifications such that *each* service classification would

169. Consol. Edison Co., Case 26105, 12 N.Y.P.S.C. 630.

170. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491.

171. *See* text accompanying note 3 *supra* for a discussion of the three principal types of costs. In Con Edison's fully-distributed cost study, which was an apportionment of costs for a specific, prior time period, the method used to apportion costs took 1970 data and assigned production and transmission costs on the basis of a combination of (1) class demands at the time of the system peak and (2) peak demands of the various classes whenever they occurred (non-coincident class demands). Con Edison's study sampled load patterns for service classifications to determine the contribution to the system's peak; it utilized the average four hour demand at the time of the summer system peak—between 1 and 5 P.M. in August 1970. Data for five hot summer days were employed to arrive at the average. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491, 1514. Costs pertaining to distribution facilities were allocated on the basis of non-coincident class demands. The staff of the Public Service Commission updated the company's study, and adjusted it for known changes so as to base the study upon the twelve months ending March 31, 1972. *Id.* at 1514-15. A new cost of service study based on 1972 data was submitted by Con Edison in the 1975 *Consolidated Edison* case. Consol. Edison Co., Case 26538, 8 P.U.R.4th 475.

172. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491.

earn a rate of return on the investment allocated to it, equal to the overall company-wide rate of return.[173] Under the company's average method of cost allocation, residential and religious customers were paying rates which earned a 6.24% rate of return compared to an overall rate of return of 6.41% based on 1970 data. The Commission's updating of the company's average method indicated that residential and religious customers were paying a 7.06% rate of return, slightly *less* than the company overall average rate of return of 7.16%. General small commercial and industrial customers were found to be paying in *excess* of 2% over the average rate of return; whereas larger commercial and industrial customers were paying rates which led to a significantly lower rate of return than the company average rate of return.[174]

The Commission upheld the principle that the rate increase should be apportioned among the service classifications to achieve a rate of return for each classification equal to the average rate of return for the utility company. To this end a tolerance of plus or minus 10% of the average rate of return would be permitted as a range within which a rate of return for a customer category would be considered average. The Commission apportioned a rate increase consistent with this ruling so that a larger percentage of the rate increase was imposed on the large commercial and industrial customers who had been returning a rate significantly below the overall company-wide rate of return. Furthermore, an increase smaller than that proposed was granted to residential and religious customers on the theory that they were already returning close to the company's average rate.[175] The Commission's decision in the

173. Testimony of Charles Olson, Record at 3354-55, Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. 1491 (Sept. 6, 1973). To arrive at a rate of return by service classification, the following calculation is made: from revenues which are derived by customer sales in a particular service classification, expenses for distribution, transmission and production, are deducted according to Commission-approved methods. This yields a rate of return by service classification which may be paralleled to that earned by taking total company-wide revenues and deducting various production, transmission and distribution expenses to arrive at an overall company rate of return.

174. With the company's average method, commercial and industrial customers were yielding a 1.64% rate of return compared to the overall average of 6.14%. With the Commission's updated method, these customers were yielding a 4.37% rate of return compared to a 7.16% rate of return. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1517; Brief for Citizens for Clean Air, Inc., as Intervenor, *supra* note 1, at 31.

175. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1518.

1973 *Consolidated Edison* case marked the first time that the Commission had set a tolerance range outside of which rates of return by service classifications could not significantly deviate. This range, moreover, was upheld against challenges to widen it to 20% made in the subsequent 1975 *Consolidated Edison* case.[176]

2. *Methods of Allocating Costs Among Service Classifications.* Until the 1975 *Consolidated Edison* case was decided, Con Edison employed in its cost of service study an allocation method which averaged equally the class demands at the time of the system peak with the non-coincident class demands. In the immediately preceding case, the 1973 *Consolidated Edison* case, the Commission concurred with the allocation method advanced by Con Edison; but some intervenors challenged the method of allocating production and transmission costs. Commissioner Jones, in a dissenting opinion, developed a cost of service study which allocated production and transmission costs only on the basis of class demand at the time of the summer peak (the so-called "peak responsibility" method). Jones allocated investment and expenses for the distribution system on the basis of non-coincident class demands.[177] The issue was temporarily resolved by the Commission's decision in that case recognizing Con Edison's own allocation method and rejecting the peak responsibility method.[178] The substance of the controversy revolved around the issue of whether customer costs for production and transmission should be those which occur only at the time of the system's peak, or whether some measure of off-peak use should be included. In rejecting the peak responsibility method in the 1973 *Consolidated Edison* case, the Commission noted that such a method ignores demands at times other than the system's peak; all customers use capacity, but under the peak responsibility method, the value of such capacity to some customers is ignored and those clients are assigned little of the costs of generation and transmission. Furthermore, the peak responsibility method does not take into account the burden of off-peak use in the fall, winter, and spring, which restricts the company's opportunity to undertake

176. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 493-94.

177. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1516, Appendix B; *id.* at 1539-40 (concurring opinion of Commissioner Jones).

178. Consol. Edison Co., Case 26309, 13 N.Y.P.S.C. at 1516-17.

repair and maintenance work. In addition, the Commission noted that the facilities needed to meet the system's peak in 1973 would be utilized within one or two years to meet growing off-peak demands. Therefore, electricity demands at the time of the system's peak should not carry the entire cost responsibility for generation and transmission facilities. The Commission ruled that the appropriate method for allocation of production and transmission costs is the averaging of the summer peak and non-coincident class demands.[179]

Intervenors in the 1975 *Consolidated Edison* case argued for a peak responsibility allocation method for production and transmission costs, and the Commission decided this method was the most appropriate.[180] The rationale behind this decision was found in testimony given by witnesses for the State of New York. Con Edison is recognized as a summer-peaking company, which is to say that the maximum demand exerted on the system takes place in the summer and that the construction and maintenance programs must be designed to meet this particular demand, since electricity cannot be stored. It is therefore reasonable to charge customers in accordance only with the demand they exert at this peak period, since it is that period which is determinant of capacity requirements. In a situation where a utility has a summer peak and the differential between summer and winter peaks is increasing, as with Con Edison,[181] the system becomes increasingly less efficient in its overall utilization of plant.

Furthermore, the effects of conservation of energy, which in the Con Edison system were found to be reducing off-peak demand to a greater extent than peak demand, exacerbate the problem of inefficient plant utilization. For these reasons, the argument was advanced that cost should be assigned in accordance only with peak demand on the system and not on the basis of an average peak and off-peak method. Indeed, convinced of the need to assign more costs to the peak method, the Public Service Commission's staff witness testified that a two-thirds peak responsibility, one-third non-coincident demand combination would be appropriate for allocating production and transmission costs.[182]

179. *Id.*
180. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 489.
181. Testimony of John Monsees, *supra* note 80, at 3882.
182. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 483.

It was testified by one witness in the 1975 *Consolidated Edison* case that recalculated, on a peak responsibility method basis, rates of return for residential customers are higher than shown in the company's cost of service study, and rates of return for commercial and industrial customers are lower. Thus, were the peak allocation method to be used to allocate production and transmission costs, residential service classifications would receive less of a rate increase than would larger-use service classifications.[183]

E. *Allocation of Costs Among Blocks Within A Service Classification*

Con Edison, in the 1975 *Consolidated Edison* case, developed a cost of service study which allocates costs to customers according to usage within a given service classification.[184] As with the allocation of costs among the service classifications, the company used an average of peak and non-coincident demand to allocate production and transmission costs to blocks of users within the service classifications. Intervenors' expert witnesses testified that this allocation method is equally inappropriate when applied to blocks of use, since a peak responsibility method would be more cost-related. A reallocation based on the peak demand would—at least in the resi-

183. This is because, while residential customers contribute 23.5% to the system peak, they are allocated a larger share, 26.4% of generation of transmission costs, under the average allocation method. While residential customers are, under the company's method, paying more than a cost-related share of demand costs, commercial and industrial customers are paying less than their appropriate share. Commercial master-metered redistribution customers were shown to be responsible for 17.3% of the system's peak, yet under the company's average allocation method, they are accorded only 16.0% of generation and transmission costs. Larger commercial and industrial users contribute 38.1% to the system's peak demand, yet they pay only 35.2% of generation and transmission costs. *See* Testimony of Dick Netzer, *supra* note 127, at 9928-29; Testimony of Carolyn Brancato, *supra* note 167, at 10129-30.

184. The company's cost study of volume usage by groups within classes separated costs into demand, energy, and customer components. The customer groups were determined on the basis of annual billed kwhr and load factor. Class demand costs were allocated to these groups on the basis of the average of customer group coincident demand at the time of the class peak and at the time of system peak. The required revenue for the demand component for each class was spread among the groups in proportion to the averages of the group coincident demand at the summer class peak and at the time of the system peak. Then, a demand cost responsibility per kw or kwhr for each group was determined.

Consol. Edison Co., Case 26538, 8 P.U.R.4th at 500.

dential classification—shift a higher percentage of the cost to higher-use blocks than the company's allocation method, since these higher use blocks tend to have more on-peak consumption.[185] The Commission agreed that it would be preferable to have used the summer peak responsibility method to determine costs.[186]

Based on the company's studies, with certain reservations noted by the Commission, the Commission ruled that there is no justification for volume discounts, as such, in the rate classes. The Commission directed that all consumption by SC-1 residential customers be priced at a single rate beyond the 10 kwhr included in the minimum charge. Certain other customers in other classes do enjoy good load factors, and it costs the company less per unit of consumption to serve them. Rate differentials were retained only when they were determined to be cost justified.[187]

Religious institutions, which were included in SC-1, were determined to have good load factors. Accordingly, the Commission ordered the company to establish a separate subclassification in SC-1 for these customers and to charge them a lower rate for use over 1,500 kwhr. A special lower rate for water heating customers was eliminated, and the company was ordered to price water heating block rates to fully recover the revenue deficiency found.[188] Small commercial and industrial customers served in SC-2 evidenced good load characteristics and relative non-coincidence of their demands with the system's peak. A price differential for usage over 900 kwhr was considered cost-justified, and the flat rate was replaced by a two-step block rate.[189] In SC-4, the commercial and

185. Testimony of William Vickery, *supra* note 127, at 9725-27; Testimony of Carolyn Brancato, *supra* note 167, at 10197.

186. In comparing the results which might have been achieved using the peak responsibility basis for assigning demand costs on the one hand, and an average of system and class peaks on the other, no systematic differences emerge.

> For SC No. 1, it appears that additional demand costs would be assigned to the higher use blocks under a peak responsibility basis than under the average basis, but, for the other classes observed, SC Nos. 2, 4, and 9, slightly lower demand costs are indicated for the higher use customers under a peak responsibility analysis. . . . [T]he company's study . . . , although not completely consistent with our decision to use a summer peak responsibility basis for allocating production and transmission costs, nevertheless provide a useful guide for analyzing the cost of serving customers within the classifications.

Consol. Edison Co., Case 26538, 8 P.U.R.4th at 501.

187. *Id.*

188. *Id.* at 501-02.

189. *Id.* at 502-03.

industrial redistribution category, the six declining-rate energy block structure was reduced to only three declining blocks. The five declining-rate demand blocks were replaced by three declining-rate blocks.[190] In SC-9, the large commercial and industrial class, the two declining-rate demand blocks were retained and the blocks for energy charges were reduced from six to two.[191]

F. *Fuel Adjustment Charges*

As fuel costs become a more significant proportion of customers' bills, the method for recovering them should be more closely scrutinized. In so doing, two trends must be kept in mind. First, the fuel costs for the nuclear base load units are projected, and in many cases have proved, to be lower than fuel costs for the fossil-fuel and older peaking units.[192] Second, variations in loads on the system necessitate operating the least efficient, less fuel-conserving units at peak periods. With base load plants tending to operate off-peak[193] and all units, including the least efficient ones, operating during peak periods, it may be more cost-related to replace the flat fuel rider with a differential-peak (higher priced) and off-peak (lower priced) fuel rider.

Proposals to roll more basic fuel costs into base rates have surfaced. The hearing examiner in the 1975 *Consolidated Edison* case made this suggestion, as did Con Edison in its currently pending rate case.[194] As fuel costs are converted into base rate charges, their rate design takes the shape of that for base rates. Ultimately this may lead to complete peak and off-peak pricing for fuel costs, which appears desirable.

G. *Price Elasticity*

The issue of price elasticity has often been raised in connection with redesigning electric rates. The most successful advocates of redesign have distinguished the issue of whether the new rate struc-

190. *Id.* at 503-05.
191. *Id.* at 506.
192. *See* Dunham, *The Consumers' Stake in Nuclear Power,* 95 PUB. UTIL. FORT. 19 (April 24, 1975).
193. Base load units are subject to scheduled maintenance which is performed off-peak, but in general these units are designed to operate at a minimum load throughout the year.
194. Consol. Edison Co., Case 26806 (N.Y.S. Pub. Serv. Comm'n.).

ture will produce a reduction in electricity consumption from the notion that rate redesign is cost-justified regardless of whether or not it results in reduced consumption. The latter argument has been more readily accepted by those commissions which are statutorily mandated to establish non-discriminatory rates.

Thus the foregoing rate design techniques (elimination of declining block rates, institution of peak pricing and seasonal differentials, etc.) can be analyzed and evaluated simply with respect to their cost justification, since most commissions have viewed price elasticity issues as corollary to the major focus of rate redesign. Benefits gained from reduced consumption would be in addition to those obtained by making rate structures more responsive to costs of service.

The New York State Public Service Commission, in shifting its emphasis from a value of service to an efficiency and incremental cost of service basis for rate-making, has explicitly advocated the use of willingness to pay, benefit, or value of service (which is a direct function of price elasticity) only in situations in which rates based exclusively on incremental costs yield companies inadequate or excessive total revenues.[195] And, in defining what may constitute economically efficient rates, the Commission has left little doubt that cost justification is paramount, and that beneficial results such as conservation will follow if prices truly reflect costs. The Commission's theory, discussed previously,[196] bears repetition here:

> An economically efficient rate structure requires that price reflect external, *e.g.*, environmental costs, as well as those explicitly borne by supplying companies. *Conservation clearly requires the discouragement of such wasteful consumption as occurs when prices are below cost*, which is necessary for economic efficiency, as well. Thus, in principle, an economically efficient rate structure should achieve the interrelated purposes of conservation and environmental protection.[197]

Recent economic data indicate that the price of electricity, to a certain extent, may indeed influence consumption. If this thesis is

195. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 481.
196. *See* text accompanying notes 88-96 *supra*.
197. Consol. Edison Co., Case 26538, 8 P.U.R.4th at 479 (emphasis added).

borne out, rate redesign not only may assess more accurately customer costs, but it may mitigate the need for the kind of rapid growth which utilities have forecast. A study done in 1971 by John Wilson, a Federal Power Commission economist, contained evidence that the residential price elasticity of demand for electricity is −1.33; that is, a 1% increase in the price of electricity produces a decrease of 1.33% in demand.[198] The Mount, Chapman and Tyrrell studies, performed at Oak Ridge National Laboratories (ORNL), used a time series analysis of 48 states in the 1946-70 period.[199] The ORNL studies found long-run price elasticities of residential demand for the three states in the New York metropolitan area in the range of −1.23 to −1.47.[200] Of course, the pressing question raised by these studies is whether the elasticity measured in a period of declining prices will be mirrored and found applicable in current and future periods of anticipated increased prices. To test the symmetrical validity of the ORNL results, a cross-sectional study was done by New York University under the direction of Dean Netzer.[201] Mark Menchin analyzed residential elasticity in eighteen counties in the New York metropolitan region using 1970 data. The results com-

198. Wilson, *Residential Demand for Electricity*, 11 Q. Rev. Econ. & Bus. 7 (Spring 1971).

199. The following short-run and long-run elasticities were found:

	Short-Run	Long-Run
Residential	—0.09 to —0.15 (OLS) —0.25 to —0.27 (IV)	—0.76 to —1.00 (OLS) —0.87 to —0.96 (IV)
Commercial	—0.10 to —0.13 (OLS) —0.71 to —0.81 (IV)	—0.80 to —1.04 (OLS) —0.87 to —0.99 (IV)
Industrial	—0.12 to —0.16 (OLS) —0.80 to —1.08 (IV)	—0.99 to —1.27 (OLS) —1.02 to —1.38 (IV)

Note: IV = Instrumental variables
OLS = Ordinary least square regression

(Source: Mount, Chapman & Tyrrell, Electricity Demand in the United States: an Econometric Analysis, Oak Ridge National Laboratory, NSF-EP-49, June 1973.)

200. D. Netzer, Electric Energy Supply in the New York Area: Environmental Damage, Economic Development and the Political Decision-Making Process, April 1, 1975, at 27 (unpublished report in N.Y.U. Graduate School of Public Administration Library).

201. Netzer, *supra* note 200.

pared favorably to the results of previous studies.[202] The statistically best elasticities were found in the range of −1.0 to −1.3.

Even though much evidence supports the theory that as the price of electricity increases demand will be reduced, it may be unwise to tie electric rates to estimates of elasticities. If a peak/off-peak pricing system were established with wide differentials between the two rates in accordance with user costs on the system, costs would be tailored to users. In addition, to the extent that price elasticity is experienced at peak periods,[203] construction requirements would be reduced. The peak and off-peak rates could be apportioned to achieve the overall revenue requirement with long-run incremental cost employed as part of the rate determining factor. Finally, with a greater incentive for channeling reduced consumption due to energy conservation into peak periods, there is a greater possibility of stopping the trend of decreasing revenues caused by energy conservation, since construction requirements and revenues to cover them will be brought into phase.

V. CONCLUSION

As regulatory commissions throughout the country accept the validity of new pricing theories for electric utilities, they will be confronted with a series of difficulties in constructing and implementing a modernized rate design. The New York State Public Service Commission has recently initiated a generic rate procedure to determine rate design policy for all the utilities in the state and

202. *Id.* at 28. Comparing his results directly to those of Anderson and Wilson, using models employing a similar range of variables, the price elasticities are:

(1)	NYU-Menchin	—1.299
	Rand-Anderson	—0.91[a]
(2)	NYU-Menchin	—1.35
	Wilson	—1.33[b]

[a] The other independent variables are: natural gas prices, household income, household size, winter and summer temperatures and, in Menchin only, the number of households.

[b] The independent variables are those specified in the preceding note, less summer temperatures.

(Source: Netzer, *supra* note 200, at 27.)

203. Testimony of Dick Netzer, *supra* note 127, at 9914-15.

to investigate methods of implementing new forms of pricing.[204] Questions under review include how to determine incremental prices and for what time period the increment is to be measured. This is a problem, since utilities have various types of plants which may be utilized in different combinations at any given time during the day or during the year, depending on the load to be provided. In theory, there are an infinite number of incremental time periods, each associated with a different operating or capital cost which could be charged to customers.

Commissions may have to balance a desire to achieve, on the one hand, a precise correlation between users and the incremental costs for which they are responsible and, on the other, a relative stability of rates. Obviously, a utility tariff can not be changed so frequently that customers are unable to make intelligent purchasing decisions. Such an approach would undermine the entire effort to change rate structures, which is predicated on the belief that consumers will make efficient choices when charged for the costs they actually impose on the system. If these efficient choices are made, the need to build new plants at a greatly increasing cost per unit, dictated by growing use at the peak, will be tempered.

Determining what period constitutes the "peak" period of maximum demand is also a difficult task. If significant differentials are to be applied to peak and off-peak usage, then the relation of time of consumption to the need to build new additions to existing plant takes on considerable importance. If a utility designs its system for an 8,000 MW capacity which is attained at 3:00 P.M. on a hot summer day, should customers using electricity at 2:59 P.M. on that day be charged the peak or off-peak price? Where should the peak period cut-off point be?

When the concept of incremental pricing is fully explored, difficult questions arise, including whether usage by new customers or increased usage by existing customers constitutes significant marginal demand on the system. Or perhaps all customers who take any power in the peak period may be regarded as imposing the significant marginal demands on the system since, at least in theory, they have the option of not taking additional service at all or not taking it at the peak period.

204. Consol. Edison Co., Case 26806 (N.Y.S. Pub. Serv. Comm'n.).

Also at issue is whether the economists' notion of what constitutes an incremental capacity cost can be practically incorporated in a price system. In theory, the marginal cost is only for new additions to plant, and the historic costs of the existing plant are largely to be ignored in setting marginal rates. Yet, basing current rates on future additions to the plant defies the traditional notion that rates should be set on the basis of the plant which is already in service in order to avoid charging present customers for the plant they have not yet used. Furthermore, if peak period users are to pay only for additions to capacity, the revenue raised may fall short of that required to insure an adequate rate of return on the overall investment.

It has been suggested that the difference in revenues be made up by increasing the charge to customers who have relatively inelastic uses (*i.e.*, as the price to them increases, they do not markedly alter their demands). However, since the science of determining price elasticity is thought quite imprecise, especially by those who are most skilled at making such calculations, many have questioned the wisdom of apportioning what could be substantial rate increases to customers based on the strength of these studies.

The New York State Public Service Commission's generic rate proceeding has confined itself primarily to determining rate design questions and, to date, the issue of determining the revenue requirement has been considered largely out of the proceeding's proper bounds. However, as issues of apportioning excess or deficient revenues arise, it is apparent that considering one without the other may prove unduly restrictive. In any event, as the Commission struggles to find a method of merging the theory with a practical way of implementing marginal cost pricing, it will have an opportunity to solve current utility problems and establish valuable precedents for commissions in other states.

Columbia Journal of Environmental Law

SCHOOL OF LAW, COLUMBIA UNIVERSITY

VOL. 2 FALL 1975 NO. 1