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Respond Data Request

Data Request No.	0279
Company Name	Office of the Public Counsel-(All)
Case/Tracking No.	ER-2007-0291
Date Requested	8/31/2007
Issue	Tariff Issue - Rate Design
Requested From	Barb Meisenheimer
Requested By	Janice Pyatte
Brief Description	Bonbright Citation
Description	Please provide a citation for your claim that James Bonbright recognizes inter-class cost allocations as an element of rate structures. If the citation provided is not from Principles of Public Utility Rates, Second Edition, Public Utilities Reports, Inc., 1988 (the version Staff owns), please provide (in hard copy) the entire Chapter that includes the citation.
Response	Please see attachments
Objections	NA

The attached information provided to **Missouri Public Service Commission** Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the **Missouri Public Service Commission** if, during the pendency of Case No. **ER-2007-0291** before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information. If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the **Office of the Public Counsel-(All)** office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to **Office of the Public Counsel-(All)** and its employees, contractors, agents or others employed by or acting in its behalf.

Security :	Public
Rationale :	NA

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OPC Exhibit No. 209
Case No(s). ER-2007-0291
Date 10-1-07 Rptr MV

The Regulation of Public Utilities

Theory and Practice

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With personal regards, —
Charles F. Phillips, Jr. 7/31/95

1988
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

the capital market with nonregulated businesses. Moreover, they are not guaranteed a fair rate of return; they are entitled to a fair return only if it can be earned. As expressed by the Supreme Court:

> . . . it may be safely generalized that the due process clause never has been held by this Court to require a commission to fix rates on the present reproduction value . . . or on the historical valuation of property whose history and current financial statements showed the value no longer to exist. . . . The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values that have been lost by the operation of economic forces.[18]

The Rate Structure. The second aspect of rate regulation, the determination of a utility's rate structure, involves the establishment of rates (prices) to be charged consumers. The problem is complex. For many public utilities, nonallocable (common or joint) costs represent a significant percentage of total costs. All public utilities have various degrees of monopoly power in the market areas they serve and all have unused capacity some of the time. For these reasons, rate structures are differentiated: both supply (cost of service) and demand (value of service) considerations enter into their development. Utilities, for example, sell the same service to different classes of buyers with the classes largely determined by differences in demand elasticities. They do not charge each class the same rate. Often, differences in rates can be justified by differences in costs. Sometimes they cannot, and discrimination occurs.

In the absence of regulation, price discrimination may be favorable to the supplying companies and to some buyers but unfavorable to the vast majority of consumers. As has already been pointed out, there is a potential for a firm with monopoly power to charge more where demand is relatively inelastic and alternatives are lacking, and less where demand is relatively elastic and alternatives are available. Moreover, special prices or rebates may be given to those in the strongest bargaining position. Yet, under conditions of decreasing costs, price discrimination may be socially desirable. The seller who discriminates might well enjoy higher sales, lower costs, and larger profits, while the seller who is forbidden to discriminate might have smaller sales, higher costs, and smaller profits or even losses. Consumers, too, may benefit from discrimination: lower prices usually result in a greater demand for — and, hence, consumption of — the utility's services. For many years the commissions and the courts supervised the utilities' rate structures to prevent undue and unjust discrimination and to insure that the benefits of discrimination were realized.

In more recent years, increasing utility rates and competition have added a new dimension to the rate structure problem. Indeed, rate design has become the most important single issue in ratemaking (at least in terms of time devoted by all the parties in the typical commission proceeding). Economists, in particular, have contended that the traditional approach, based on average total or embedded cost, must be replaced with a marginal cost approach to insure economic efficiency and promote conservation; competition has forced such a reexamination, since rates are forced toward the cost of service as internal cross-subsidies among services are no longer tenable. But the adoption of marginal cost pricing involves numerous theoretical and practical problems, and the concept is even "feared" by some competitors and customers. And then there are those who contend that they are unable to afford utility services, regardless of how the prices for such services are determined.

The Phases of Rate Regulation

A former electric utility executive has pointed out that the history of public utility regulation consists of three major phases — legislative, judicial, and administrative.[19] The legislative phase began with the *Munn v. Illinois* decision in 1877,[20] when the Supreme Court upheld the right of the state of Illinois to regulate grain elevators under its police power. By implication, the constitutionality of other state laws regulating private firms also was established. The Court ruled, however, that the regulation of rates was a legislative function and that recourse against the abuse of that function must be at the polls and not from the courts. In 1890, the Court reversed its position, saying that the reasonableness of rates was subject to judicial review.[21] This decision marked the beginning of the judicial phase that was to last over four decades.

Throughout this period, the judiciary was to dominate regulatory policy. The *Smyth v. Ames* decision in 1898[22] listed a number of factors that the commissions should consider in determining the value of a company's property, but it did not assign a weight to each one. So started the valuation controversy concerning original cost versus reproduction cost, which was to occupy much of the commissions' and utilities' time for many years. The Court, especially after the first World War, emphasized reproduction cost, as did the utilities, while many commissions favored original cost. Then, in the *Bluefield* case of 1923,[23] the Supreme Court enumerated a number of factors the commissions should consider in determining the rate of return. Again, however, no weights were assigned to the various factors. In general, the Court found that a utility was entitled to a return "equal to that generally being made at the same time and in the same general part of the country on investments and in other business undertakings which are attended by corresponding risks and uncertainties."[24] The comparable earnings standard, which had been developed in earlier cases, was reaffirmed.

These two judicial decisions, in particular,

Chapter 10 THE RATE STRUCTURE

There are two basic functions of price; to discourage the buyer of a commodity (or service) from using up too much of it, and to induce the supplier to produce enough. But what is the right amount? What is enough and not too much?

—*Abba P. Lerner**

The preceding three chapters concerned determination of the rate level. The end result is the total revenue requirement of a public utility. The next step is the rate structure — determination of the specific rates that will yield the required revenues.

Historically, public utility rate structures were developed by the companies themselves and, more particularly, by their engineers. The theoretical basis for the resulting structures was too often difficult to discern, other than an obvious emphasis on promoting usage. Like most private firms, utilities considered market (demand) factors as well as cost (supply) factors in determining their rate structures. Discrimination often resulted; discrimination, some contended, that was not "just and reasonable."

The situation has changed completely, as the emphasis in regulatory proceedings has shifted to rate design. The theoretical principles are being developed. This shift in emphasis has resulted from three developments. First, as Kahn has noted, management generally has adopted "increasingly sophisticated economic criteria and techniques in formulating investment and price policies."[1] Second, the development of competition has forced utilities to abandon their traditional pricing policies, as rates have been forced toward cost of service. Finally, the acceleration in the rate of inflation, the environmental movement, rising fuel prices, and conservation have affected public utility costs and, hence, rates. These pressures too have compelled both the regulated and the regulator to rethink proper pricing principles.

Nor can the role of the federal government in this reexamination process be overlooked. On the one hand, competition has been promoted by federal agencies, often over objections from the state commissions. On the other hand, the federal government assumed an important input into rate design through enactment of the national energy plan in 1978. Specifically, the Public Utility Regulatory Policies Act (*a*) required the state commissions to consider, and to implement or adopt if appropriate, any or all of twelve specified standards in the case of electric utilities, (*b*) initiated a gas utility rate design study, and (*c*) gave to the Department of Energy the right to intervene in state electric and gas utility rate proceedings to advocate reforms.

The legal standards guiding the regulatory commissions are broad. Each specific rate must be "just and reasonable." Further, "undue" or "unjust" discrimination among customers is prohibited. The rate structure thus involves determination of specific rates and determination of rate relationships.

The theory of rate design is discussed in the first sections of this chapter: the criteria of a sound rate structure, the bases for price differentiation, the economics of price discrimination, and the theory of marginal cost pricing. A special case — lifeline rates — is discussed in the fifth section. The concluding section considers rate design with respect to the electric utility industry.[2]

Criteria of a Sound Rate Structure

Bonbright, in his study on public utility rates, lists eight criteria of a sound or desirable rate structure. They are as follows:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful

use of service while promoting all justified types and amounts of use:

(a) in the control of the total amounts of service supplied by the company;

(b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[3]

Admittedly, these criteria are broad and ambiguous (what, for example, is "undue" discrimination?). They also overlap without offering any rules of priority in case of conflicts. How is the "cost of service" to be measured — marginal cost, average cost, or fully distributed cost? Clearly, the measure largely depends on the purpose that a rate is to fulfill. Further, is the dominant objective one of "fairness" or one of "efficiency"?[4] But the criteria are of value "in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to 'scientific' principles of optimum pricing."[5]

Bonbright further suggests that the three primary criteria are numbers 3, 6, and 8; namely,

> . . . (a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* among the beneficiaries of the service; and (c) the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received.[6]

Cost and Demand: Price Differentiation[7]

There are two bases for price differentiation. The first is differences in costs or the "cost of service." The second is differences in demand or the "value of service." A seller does not discriminate when rates are based upon costs, even though some customers pay more than others. But when rates are based upon demand, discrimination occurs.

Cost of Service

Differences in rates may be due to differences in costs. It is more expensive to serve some customers than others. Those who use the service only occasionally are more expensive to serve than those who use it continuously. The costs of billing each type of customer, for example, may be approximately the same, so that average costs are higher for the first group than for the second. For the telephone industry, terminal costs are as high for short distances as for long distances, so that costs per mile decline with distance. In the case of electric utilities, little of the distribution plant is applicable to large industrial sales, resulting in a significant cost difference between industrial and residential or small commercial users.

Costs also vary according to the time of use. Customers who use the service during the peak demand period are more expensive to serve than off-peak users. A basic factor in determining the size of a utility plant is the peak demand. Therefore, it costs less to serve those customers who use the service without burdening the business as a whole by adding to the peak demand period. Further, if off-peak usage is increased, the utility may obtain a better utilization of its plant throughout the day, thereby resulting in a larger total output over which fixed costs may be spread.

Value of Service

Differences in rates may be due to differences in demand. A customer's demand is based upon the need or desire for the service, the ability to pay for it, and the availability of substitutes. Customers have relatively elastic demands when they have little need for the service, when they have insufficient incomes to pay for the service, or when they can provide it for themselves or purchase it from a competing seller. Customers have relatively inelastic demands when their need and ability to pay for the service are great and when no alternative sources of supply or substitutes are available.

From the seller's point of view, discrimination may offer marked advantages. When a supplier can fully utilize his plant and earn a fair rate of return by charging a single price, he is unlikely to practice price discrimination. But a price low enough to maintain full production may yield insufficient revenues to cover costs, while one set high enough to cover costs may result in unused capacity. In such a situation, the supplier will be able to increase his revenues by charging a higher price where demand is inelastic and a lower price where demand is elastic.

This situation is illustrated in Table 10-1. Assume that an enterprise has a plant with a capacity of 3,800 units. Assume further that total cost includes a fair return on the investment in the plant, so that the final column represents either excess profit or loss. If the firm's output is sold at a single price, the rate will be $8.00 and sales will be 400 units. Profits are maximized. At this price, the plant is not fully utilized. A glance at the table will show that it is impossible for the firm to both cover costs and maintain full production as long as a single price is charged.

If discrimination is practiced, however, the situation is quite different, as shown in Table 10-2. Now, by dividing customers into separate classes and

TABLE 10-1

Enterprise Selling at a Single Price

Price	Sales	*Total Revenue*	*Total Cost*	*Profit Or Loss*
$11.00	100	$1,100	$ 1,600	−$ 500
10.00	200	2,000	2,150	− 150
9.00	300	2,700	2,650	+ 50
8.00	400	3,200	3,100	− 100
7.00	500	3,500	3,500	0
6.00	700	4,200	4,250	− 50
5.00	1,000	5,000	5,400	− 400
4.00	1,400	5,600	6,700	− 1,100
3.00	2,000	6,000	8,200	− 2,200
2.00	2,800	5,600	10,000	− 4,400
1.00	3,800	3,800	13,000	− 9,200

TABLE 10-2

Enterprise Practicing Price Discrimination

Price	*Sales*	*Sales in Each Class*	*Revenue from Each Class*	*Total Revenue*	*Total Cost*	*Profit Or Loss*
$11.00	100	100	$1,100	$ 1,100	$ 1,600	−$ 500
10.00	200	100	1,000	2,100	2,150	− 50
9.00	300	100	900	3,000	2,650	+ 350
8.00	400	100	800	3,800	3,100	+ 700
7.00	500	100	700	4,500	3,500	+ 1,000
6.00	700	200	1,200	5,700	4,250	+ 1,450
5.00	1,000	300	1,500	7,200	5,400	+ 1,800
4.00	1,400	400	1,600	8,800	6,700	+ 2,100
3.00	2,000	600	1,800	10,600	8,200	+ 2,400
2.00	2,800	800	1,600	12,200	10,000	+ 2,200
1.00	3,800	1,000	1,000	13,200	13,000	+ 200

charging each one a different price, total revenue will increase. Prices will range from a high of $11.00 to a low of $3.00, output will expand to 2,000 units, and excess profits will rise to $2,400. Yet, as will be demonstrated below, such a schedule would be considered as "unduly" discriminatory.

The Economics of Price Discrimination

When a firm sells the same service at rates which are not proportional to costs, discrimination results. Stated another way, discrimination occurs when rates are based upon differences in demand, rather than differences in costs. Consequently, some buyers will pay more than the cost of the particular service; others will pay less. It must be noted, however, that discrimination is not unlimited. As sellers cannot force customers to pay more than they believe the service is worth, the upper ceiling is the value of service. A price set above this limit would result in reduced sales. The lower limit is the seller's marginal (sometimes referred to as out-of-pocket) costs. Any sales made at a price below this limit would result in losses, since these costs can be avoided by not producing the output. When fixed costs are high, as in most of the utility industries, these limits are wide, thereby leaving considerable latitude for discrimination.

Unavoidable versus Intentional Discrimination

Discrimination is partially unavoidable. The cost of providing a particular service is difficult, if not impossible, to determine accurately. Some variable costs, such as labor and fuel, are easily identified with a unit of output. Other costs, however, are commonly or jointly incurred in rendering different types of service. Rather than varying directly with output, they decline in importance as output increases. These costs include interest, depreciation, investment in plant and equipment, and administrative overhead. When investment is large, such costs represent a significant percentage of total costs. When the same plant or equipment is used to provide several types of service, there is no one correct way to allocate these costs among the different units of service. Any method of apportionment is subject to dispute, as was demonstrated in Chapter 6 when separations procedures were discussed.[8] Even if firms tried to base their rates upon costs, therefore, a substantial element of judgment is involved.

Discrimination is also intentional. As previously shown, when one rate is charged for a service, a company may not be able to utilize its capacity fully. Only by discrimination may idle capacity be eliminated. Furthermore, discrimination is often socially desirable. If it allows a company to expand its sales and utilize its facilities more fully, average costs are reduced as fixed costs are spread over more units of output and the firm's profits are increased. Fuller utilization, in turn, may result in lower prices for *all* customers and in a wider use of the utility's services. Some services might be offered that would not be available under uniform rates or only available at substantially higher rates: interstate toll calls over low density routes often are subsidized by revenues from high density routes. Regional development also may be encouraged: low electric rates encouraged its use and attracted industry to the TVA area. These advantages, however, are unlikely to be realized unless rates are controlled. As Sharfman has pointed out, there is an inherent danger in discrimination:

> The "value of service" principle, as a basis for rate-making, provides at best a vague and indeterminate formula, rather easily construed as justifying any system of rates found expedient by the carrier. Taking the words in their most obvious sense, no rate can exceed the value of service and still continue to be paid by the shipper.[9]

The Conditions for Discrimination

Rate discrimination is not possible unless the market can be separated into distinct sectors so that (*1*) customers who are charged the higher rate cannot buy in the low-rate sector and (*2*) those buying at the lower rate cannot resell in the high-rate sector. For industries selling transferable products, this is usually not possible.[10] However, for public utilities which sell services, such a division of the market is possible. Moreover, they are able to control the use of their services, since they generally deliver them to the customer as they are consumed. If a telephone company charges a business customer more than it charges a residential user, the business subscriber cannot obtain the lower rate by connecting his telephone with the residential subscriber's lines. Customers of utilities cannot shift between the established sectors. This condition further implies that the discriminating firm is either free from competition or that competition is controlled. If two firms supplied the same market, their rivalry for business would force rates down.

Two other conditions for discrimination also must exist.[11] The elasticities of demand in the established sectors of the market must be considerably different. That is, if the elasticities are equal or similar, so, too, will be the marginal revenue curves, and discrimination would serve no purpose. Finally, the cost of separating the market into sectors must not be too large. Rate discrimination involves some extra expense. Different bills, for example, usually must be printed for each type of customer, and bookkeeping becomes more complex. For discrimination to be profitable, the increase in revenues must be greater than the additional expenses incurred.

The Case for Discrimination

Discrimination may be advantageous for two reasons. First, it may result in a fuller utilization of a firm's plant and equipment, and a wider consumption of its service. Second, it may lead to lower prices for all customers. The first was illustrated above, where adoption of price discrimination raised output from 400 units to 2,000 units. The second can be seen in Table 10-3. Here, the prices, sales, and costs are the same as those in the previous tables. But now it is assumed that a regulatory commission controls the firm's rate structure. It was suggested earlier that the rate structure shown in Table 10-2 involves "undue" discrimination because of the presence of excess profits. If discrimination were not allowed, therefore, the commission would force the seller to produce 500 units, which would sell for $7.00 each, as shown in Table 10-1. At this price, there would be no excess profits.

TABLE 10-3

Enterprise Practicing Price Discrimination under Regulation*

Price	*Sales*	*Sales in Each Class*	*Revenue from Each Class*	*Total Revenue*	*Total Cost*	*Profit Or Loss*
$5.00	1,000	1,000	$5,000	$ 5,000	$ 5,400	−$ 400
4.00	1,400	400	1,600	6,600	6,700	− 100
3.00	2,000	600	1,800	8,400	8,200	+ 200
2.00	2,800	800	1,600	10,000	3,100	0
1.00	3,800	1,000	1,000	11,000	13,000	− 2,000

*This rate structure is only one of several possible structures that might be established by a company and accepted by a commission.

By allowing discrimination, the commission could establish the rate schedule shown in Table 10-3. A fair return is earned from a scale of prices that begins at $2.00 and rises to $5.00, while the volume of output is raised to 2,800 units. It should be noted that every price is well below the $7.00 that would have to be charged if discrimination were not allowed. This schedule is made possible because by serving the low-rate customers who cannot afford the service at a higher rate, the firm's fixed costs are spread over more units. As a result of the adoption of such a schedule, no customers are harmed. On the contrary, all of them have been helped: the $5.00 customers have saved $2.00 per unit, while the $4.00, $3.00, and $2.00 rates are required to obtain customers that otherwise could not afford the service.

Such discrimination cannot be justified, however, unless (*a*) there are high fixed costs and chronic unused capacity, so that costs per unit are reduced as the fixed costs are spread over a larger volume of output; (*b*) the lower rates are needed to attract new business; (*c*) all rates cover at least variable costs and make some contribution to fixed (overhead) costs; and (*d*) regulation is undertaken to keep total earnings reasonable and to keep discrimination within bounds. If these conditions exist, discrimination is desirable, since it leads to either an increased use of the facilities or to a lower rate for the customers discriminated against. At the same time, it is important to remember that each rate must be set with the thought that all rates together should return to the utility sufficient revenue to cover its total cost of service, including the rate of return allowed by the commission. This statement does not imply that such revenue is guaranteed; rather it simply means that this end should be kept in view.

The Case against Discrimination and Embedded Costs

Under conditions of decreasing costs, and assuming a goal of expanding service to a maximum number of consumers, few would challenge the desirability of discrimination.[12] But such discrimination does not promote economic efficiency, particularly under conditions of increasing costs, for consumers are given improper price signals. Correct price signals — and the achievement of economic efficiency — require marginal cost pricing, and herein lies the controversy concerning rate design.

Utility rate structures, as they were developed over the years, represented a complex and confusing mixture of cost of service and value of service considerations, with the promotion of use as the dominant objective. To the extent that rate structures were cost-justified, they were based upon historical embedded (average or fully distributed) costs. In the words of the Colorado commission:

> For example, a utility will establish an actual test year for determining revenue requirements and utilize the historical costs for purposes of functionalizing and allocating the costs to various classes of customers for purposes of establishing rates. In that fashion, both the revenue requirements and the rates ultimately determined are based upon the average costs for the historical test year. . . .[13]

In many instances, however, discrimination was not justified. Further, rate structures contained countless internal subsidies: off-peak users subsidized on-peak users, industrial and commercial customers subsidized residential customers (electric and gas), and long-distance (toll) calls subsidized local exchange service (telephone), to cite only a few examples. Many customers, in short, paid a rate that did not reflect "the marginal social opportunity cost of supply."[14] Those who paid less were encouraged to demand more service; those who paid more were encouraged to demand less service.

By the early 1970s, recognition was growing that such rate structures were incompatible with the new economic environment. Promotion was no longer rational, since new capacity resulted in higher average costs. And competition was forcing some rates toward marginal costs, since internal subsidies require monopoly conditions.[15] Not only were customers being given improper price signals, but utilities found that rates based upon past costs and sales, during inflation, resulted in constant revenue deficiencies. For these and other reasons, the emphasis began to shift to marginal cost pricing.

Marginal Cost Pricing: Theory and Practice

The economic literature has long provided the theoretical framework of marginal cost pricing; that is, the pricing of all goods and services at marginal cost.[16] Until recently, however, little attention has been devoted to the problem of translating abstract theory to practical application, particularly with respect to public utilities,[17] although the marginal cost pricing principle has been widely employed in France and England.[18] But with the exposure of public utilities to competitive market forces, rising costs, and more elastic demand conditions, marginal cost pricing principles have received increased attention in the literature and in regulatory proceedings.

The Theory and Qualifications

Under the equilibrium conditions of pure competition, as explained in Chapter 2, price, which represents what consumers are willing to pay for the last unit of a good or service, is equal to the cost of producing that last unit; that is, marginal cost. As a result, the consumers' valuation of the last unit and the cost of producing the last unit are equal. This equilibrium results in a socially optimum volume of output and a minimum cost of producing the volume. The theory, however, is subject to two qualifications:

> . . . The first qualifying consideration is the cost of administering such a pricing system: obviously, economic efficiency requires that we move toward marginal cost pricing only so long as the additional cost of developing and administering a closer approximation to it is exceeded by the incremental benefit. Notice that even in this decision marginal costs remain the controlling criterion. The second qualification is the principle of second-best: in deciding to what extent and whether to price at marginal cost in a particular market, it is essential to take into account the presence of imperfections elsewhere in the system, in particular the extent and direction in which prices in other markets may diverge from that standard. Both of these qualifications counsel taking into account such other considerations as the possible desirability of avoiding excessive fluctuation of rates over time.[19]

The first qualification is self-evident; the second requires brief consideration. It has been shown that unless prices are equal to marginal costs in *all* industries, an optimum allocation of resources (in the Paretian sense) cannot be achieved.[20] The "problem of the second best" is both a disturbing and a serious one "in an economy shot through with imperfections of competition, monopoly power, and government taxes and subsidies, causing all prices to diverge in varying directions and degrees from marginal costs."[21] At a minimum, the problem suggests that second-best considerations must be taken into account in designing rates. Contends Baumol:

> Over the whole of the discussions . . . there looms most menacingly the injunction of the theorem of the second best: Thou shalt not optimize piecemeal. But I would argue that in practice this admonition must be softened lest otherwise all effective policy be stultified. I would propose, instead, that one should shun piecemeal ameliorative measures that have not been sanctioned by careful analysis and the liberal use of common sense. Many policies may plausibly be expected to yield improvements even though things elsewhere are not organized optimally.[22]

Marginal Cost Pricing: From Theory to Practice

Despite these qualifications, economic efficiency requires marginal cost pricing. Implementation of marginal cost pricing, however, raises a number of issues, considered below as threshold issues, time-of-day considerations, and minimum rates.

Threshold Issues. Marginal cost pricing raises three basic threshold issues. The first issue concerns the proper time frame; that is, short-run versus long-run marginal costs. The term short-run refers to a period of time in which some productive services are fixed in amount; most typically, the plant capacity (capital) is fixed.[23] Here, a distinction must be made between fixed or constant costs and variable costs. Only variable costs affect the calculation of short-run marginal costs, for they are the only costs which vary with changes in the rate of plant utilization. Thus, if a plant is operating at less than full capacity and fixed costs are high, short-run marginal costs will represent a small fraction of average total costs. In a long-run period of time, the capacity of a plant can be varied. All costs are variable. The long-run marginal costs, therefore, represent the increments in total costs as plants of different sizes (capacities) are put into operation.

Strict application of marginal cost pricing requires that price equal short-run marginal costs. As Kahn has noted: "no airplane should take off unfilled so long as there exists some potential passenger who would place a greater value on making that single flight than the almost negligible short-run variable cost of adding him to the flight roster; and no sale should be made, whatever the possibly lower costs of making it on a continuing basis, whose incremental variable costs exceed the *value of that single unit* of service to a customer."[24] Put another way, price-output decisions should be governed by short-run marginal costs. Such costs, however, are extremely volatile. As the volume of output expands, for example, short-run marginal costs change more rapidly than do average costs. Rates, in turn, would have to be changed frequently in accordance with variations in the volume of output. Further, it is long-run marginal costs which should govern investment decisions.

There is a variant of the theoretical marginal cost principle which has greater practical application; that is, the long-run incremental cost (LRIC) concept. This concept, unlike the concept of short-run marginal cost, recognizes that utilities add capacity in discrete units and on a continuous basis. The long-run incremental cost concept thus includes the future costs of supplying utility services, as opposed to the average cost of serving existing customers. Stated the Wisconsin commission in its 1974 *Madison Gas and Electric Company* decision:

> 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.
>
> It must be understood that the "long-run" concept is pursued as the most appropriate and 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 inflationary cost increases. The primary objective that the LRIC-based rates are intended to accomplish is to guarantee an efficient allocation of resources directed toward the production of electricity. . . .[25]

The relevant future time frame is largely a matter of judgment. Argues Kahn:

> . . . What we are trying to measure is how costs will differ, after a span of time sufficiently long for the system planners to adapt the supplying system to the change, by virtue of taking on some specified incremental block of sales on a continuing basis, as compared with not taking it on. Measurement is, to be sure, another matter. What I suspect we are likely to have, mainly, is a measure of the average, full additional costs, for all additional sales undertaken on a continuing basis, over whatever is the reasonable planning period for additions to capacity — possibly on the order of ten to twelve years for electricity, perhaps three to five years in communications. . . .[26]

It is the very indefiniteness of the relevant time frame that leads Melody, among others, to question the long-run incremental cost concept:

> . . . The framework for marginal cost analysis assumes a planning horizon sufficiently distant that all the effects of all alternative decision possibilities can be taken into account. But all of this information is hypothetical and subject to the forecasting ability of the decision maker. Once the optimum alternative is selected and pursued, the firm must await the judgment of reality to see if its decision was good or bad. If the firm correctly perceived and made perfect forecasts for all alternative decision possibilities, its decision indeed will have been optimum. If it did not, its marginal cost calculations will have been inaccurate. As a practical matter we know in advance that our hypothesis of optimization will be disproved by reality.[27]

Closely connected is a second threshold issue; namely, the calculation of marginal or incremental costs. With respect to electric utilities, for example, several different methodologies have been developed for the calculation of incremental costs.[28] Consider the issue of estimating the annualized capacity cost per kilowatt of new capacity. There are two major methods used for making such an estimate, as summarized by Crespi:

> . . . One method developed by the National Economic Research Associates (hereafter referred to as the NERA method) uses as an estimate the annualized average cost per kilowatt of a gas-fired peaking generation unit plus the annualized average cost per kilowatt of the associated incremental transmission and distribution investment. The other major method considers what changes will take place in a utility's actual system expansion plan as a result of an upward shift in the trend path of system peak demand, calculates the present value of the resulting change in overall system costs over time, and converts this figure to a per kilowatt basis. This method was developed by Charles J. Cicchetti and others (herein referred to as the CGS method).
>
> The strength of the NERA method is that the cost of a new gas-fired peaking unit is relatively easy to determine. The major weakness is that, by law, no more such peaking units may be installed so that it is not clear what relation, if any, such hypothetical figure would bear to actual system marginal capacity costs.
>
> The main strength of the CGS method is that it is based on the actual expansion plan of the system. The major weakness is that to apply it one must have reasonable estimates of various system costs many years in advance; figures that are notably unreliable.
>
> Once one has estimated by some method the annualized marginal costs of one kilowatt of new system capacity one must determine how these costs will be allocated to the kilowatt-hours provided in each of

the costing periods. One method is to apportion the marginal capacity costs equally over all hours of the "peak" costing period (the CGS method). This method implicitly assumes that any hour in this period has an equal probability of being the actual capacity-determining system peak hour, and that no hour outside this period has any positive probability of becoming the system peak. Another method is to assign these marginal capacity costs to costing periods in proportion to the average "loss-of-load" probabilities for hours in each costing period. Again, subjective, challengeable judgments are required of the analyst.[29]

The third threshold issue concerns the required adjustments to incremental costs. The required adjustments fall into three categories. First, adjustments may be required because of the theory of the second best, as previously discussed. Second, adjustments may be required to meet a utility's total revenue requirement; a revenue requirement that is determined on the basis of embedded (average) costs. Whenever incremental costs exceed embedded costs for a utility, overcollection of revenues will occur; whenever embedded costs exceed incremental costs, undercollection of revenues will occur. Several methods of making rate adjustments exist. Assume an overcollection situation. One adjustment method, widely supported by economists, is the inverse elasticity rule; departures from marginal cost pricing should be inversely proportional to the elasticity of demand.[30] Those customers with elastic demands would be charged marginal cost-based rates; those customers with inelastic demands, would be charged rates below marginal costs. In this way, prices below marginal cost "would distort consumption decisions as little as possible."[31] Another method is to lower or eliminate the customer charge.[32] A third method is to adopt an inverted rate structure, in which the tailblock rate reflects marginal costs and "the initial block or blocks are set at a low enough level to meet the revenue requirement."[33]

Third, adjustments may be necessary to account for social costs. As summarized by the Department of Energy:

> Although there are external or social costs associated with the production of electric power, to a large extent these social costs have already been internalized and accounted for in the determination of electric utility rates. As a result of both Federal and State environmental and safety regulations, electric utilities have been required to incur considerable expense to reduce these social costs; and these expenses for pollution abatement and the maintenance of public health and safety are now included by the utilities and their regulators in the prices that consumers must pay for electricity.
>
> Other important social costs associated with the production of electricity at the margin may be found to exist, which have not been imposed on the producers of electricity. In such cases if the magnitude of

these social costs can be quantified, these costs should be included in the calculation of marginal costs.[34]

Time-of-day Considerations. Marginal cost pricing requires time-of-day (peak-load) rates, since marginal costs vary at different times of the day (and, perhaps, by different seasons). It must be emphasized, however, that time-of-day considerations also are relevant when embedded costs are utilized.[35]

Public utilities historically have paid some attention to peak and off-peak pricing. Commercial and industrial electric rates, for example, have included a separate demand charge although, until recently, the charge was generally based on the maximum kilowatts of electricity used by the customer, regardless of when that demand occurred. Today, the demand charge is frequently based on the maximum kilowatts of demand of the user during the utility's expected peak period. Many electric utilities, moreover, have offered residential customers special rates for off-peak water heating. In more recent years, many electric utilities have adopted a seasonal rate structure (*i.e.*, a summer/winter differential), where there is a high or significant seasonal peak. Long-distance telephone rates, since the mid-1960s, have reflected time-of-day considerations (although such rates were not based on marginal costs).

Time-of-day rates require a significant investment in metering equipment, thereby raising a cost-benefit question. Are the metering costs (as well as other administrative costs associated with a more complex rate structure) outweighed by the potential for minimizing peak usage and the required, associated plant capacity? Or, conversely, will time-of-day rates simply result in a shift in a utility's peak period, rather than in a real peak period reduction? (In the mid-1960s, when the Bell System reduced long-distance rates after 9 P.M., the System's peak was shifted from business hours to evening hours.)

Nissel has argued that peak-load rates, for electric utilities, "are . . . not a suitable device for producing capacity or energy savings," for two basic reasons: first, because "price signals do not work," and second, because peak periods may be too long; *i.e.*, twelve to fourteen hours.[36] Acton and Mitchell contend, however, that the evidence clearly shows that time-of-day rates have changed industrial load curves, both in the United States and abroad.[37] But there is little concrete evidence to date about residential time-of-day effects, although seasonal rates (which require little or no additional metering and administrative costs) have been beneficial.

So, too, may interruptible rates be beneficial, when they involve relatively large loads. Under such rates, an electric or gas utility can turn off service for specified periods of time during system peaks. There are appliances which permit interruption for limited times, while still providing the customer with a satisfactory level of service — air conditioners, water heaters, swimming pool heaters, space heaters, and certain types of pumps and compressors, to name a few of the more obvious examples. Under interruptible rates, customers receive lower rates, since they do not have any demand or capacity costs. Interruptible service can be an important load management technique.

Minimum Rates. There is another use of the marginal cost concept that is more familiar in ratemaking. Frequently, commissions have stated their refusal to allow rates to fall below out-of-pocket costs. If out-of-pocket costs are the same as marginal costs, commissions may be employing marginal costs as measures of minimum rates.

Bonbright has pointed out that the terms out-of-pocket cost and marginal cost may be only approximate synonyms as used by the commissions. In his words:

> "Out-of-pocket cost," itself an ambiguous term, is the popular partial equivalent of "marginal cost," especially in railroad parlance. But it is sometimes used to refer merely to the additional *cash* outlay imposed directly by the production of additional output, where "marginal cost" also includes any enhancements in noncash costs (such as depreciation due to wear and tear of equipment) attributable to an increase in rate of output.[38]

Moreover, whether minimum rates should be based upon short-run or long-run marginal costs represents an important dilemma. The argument in favor of short-run marginal costs as a basis of minimum rates is that rates should be determined by the current costs of providing the service. The aim is to increase consumption in order to make full use of the existing capacity or, when present plant capacity is inadequate to satisfy demand, to raise rates in order to limit consumption. This position,

> . . . that utility rates should approximate short-run marginal costs, at least to the maximum extent permitted by the requirement that rates in the aggregate must cover total costs, is in accord with the view that public utility rate making should accept competitive price standards of reasonable rates and rate differentials. For, under the theories of pure or perfect competition, prices are supposed to tend to come much more quickly into accord with short-run marginal costs than in accord with long-run marginal costs.[39]

The argument in favor of long-run marginal costs as the correct measure of minimum rates is based on a conviction that a firm's rate level and rate structure should be as stable as possible. If short-run marginal costs were employed, rates would change rapidly as the volume of production increased or decreased. This change, in turn, would pose an increased burden on the regulatory commissions. Further, many argue that consumers often consider long-run, anticipated rates when deciding between substitute services (oil versus gas heating, gas versus electric ranges). Bonbright argues:

> Once these commitments have been made, the demand for utility services consequent thereon will be largely predetermined by the consumers' investment in equipment and will depend only to a minor extent on any temporary changes in rates of charge. In other words, the demand for public utility services is likely to be much less elastic in the short-run than in the long-run.[40]

On balance, should minimum rates be determined by short-run or long-run marginal costs? Despite the greater difficulty of measurement, most economists would probably favor the long-run.[41] In using the concept of long-run marginal costs, the added costs of providing a service (*e.g.*, the additional operating expenses and the cost of any additional construction, including a full rate of return thereon) would be taken into account. Only when a firm has significant and continuing excess capacity (such as off-peak periods) may short-run marginal costs be a better guide to pricing decisions.

It is important to emphasize, however, that marginal costs set the lower boundary — the floor below which rates should not fall.[42] But they should not determine rates, for the upper boundary is set by demand conditions and regulation.[43]

The issue of minimum rates has occupied much of the time of the Interstate Commerce Commission, due to the existence of intermodal competition.[44] But the issue, particularly during the 1970s, also became of importance for the telecommunications industry.

Lifeline Rates: A Special Case

The basic principles of rate design have been considered in the previous sections. There is an additional issue, however, that has been of growing concern over the last decade; namely, lifeline rates. While the lifeline concept has been subject to various interpretations, the major premise of those advocating lifeline rates is that low-income and elderly customers can no longer pay for "basic" utility services and, since such basic services are both "essential" and inelastic, they should be provided at "an 'affordable' rate, even if that rate is below the cost of service."[45] Some, moreover, contend that lifeline rates also will promote conservation; *i.e.*, an initial low-priced block of electricity, for instance, will result in a higher price for usage above the lifeline threshold level.

The Issues

The issues surrounding the lifeline concept are as complex as they are numerous.[46] The following discussion is intended to be illustrative and not all-inclusive.

Perhaps the initial question is whether the lifeline concept should be considered by the legislative branches or by the regulatory commissions. Some maintain that the legislative branches should properly be concerned with social welfare programs and that only the legislative branches can consider all of the options to lifeline rates; *i.e.*, tax credits, energy or telephone stamps, and direct subsidy programs.[47] Lifeline rates, in other words, have limitations: they are of no aid to those who pay for utility services indirectly through their rent.

When regulatory commissions have considered the lifeline concept — and most of them have, since such an inquiry is required under the Public Utility Regulatory Policies Act of 1978[48] — concern has been expressed, first, about unfair preference and, second, about the proper mechanism for establishing lifeline rates. Unfair preference may arise when a special, low-priced block is offered to a limited segment of a class without regard to the character of the service provided.[49] Even where statutes permit a distinction based on age or income, the issues of administrative costs and increased costs to other customers must be considered. Such unfair preference could be avoided by providing a low-priced block for *all* customers in a class and thereby avoiding a distinction based on age or income. But in that case, several other questions arise.

Are the poor or elderly minimum users, or does energy use (to illustrate) depend upon such other variables as type of dwelling, family size, and life-style?[50] If lifeline rates are available to all customers in a class, the initial low-priced block might have to be sufficiently high that many users in that class would actually experience lower bills, thereby encouraging consumption and discouraging conservation. The problem, of course, is that while most lifeline proposals are based upon end uses, it is not easy to identify individual customer's "essential" needs; they "would vary monthly depending on temperatures, amount of time spent at home, number of loads of wash, and other factors."[51] And, when the initial low-priced block is kept below the cost of service, who would pay the subsidy (*i.e.*, the revenue deficiency): all residential users above the lifeline threshold level or commercial and industrial users? If the revenue deficiency were placed on the residential class (above the initial block), high-usage but low-income consumers would face significant rate increases. If the revenue deficiency were shifted to the commercial or industrial class, they "might be able to pass their higher electric costs back to the poor in the form of higher prices for food, rent, and transportation" while, at the same time, making businesses in a state "less competitive, reducing the level of economic activity in the state and injuring the poor by decreasing employment opportunities and reducing the tax base that provides the source of existing income supplements."[52]

Lifeline in Practice

In the case of telephone service, the separations process (discussed in Chapter 6) long provided a subsidy to local exchange service. However, partly in response to pressure for lifeline rates, the industry began to introduce a new option to flat rate service throughout the country — measured service. Under measured service, a subscriber can elect the so-called "economy" service; for a flat rate per month the subscriber is tied into the network and then pays for each outgoing local call.[53] A few states have implemented lifeline rates.[54] And there are three FCC lifeline plans available to states that are certified by the commission, that waive the federal subscriber (access) line charges and provide assistance toward phone-service connection charges for qualifying low-income households.[55]

In the case of electric and gas service, several different types of lifeline rates have been approved. Four examples are illustrative:

1. California was one of the first regulatory commissions to institute lifeline rates. Rate schedules for residential users of electricity and gas were inverted. Under the Miller-Warren Energy Lifeline Act, "the lifeline rate shall not exceed rates in effect as of January 1, 1976," and "no increase in the lifeline rate [shall be authorized] until the average system rate in kilowatt-hours or cents per therm has increased 25 per cent or more over the [level prevailing on January 1, 1976]." Further, in determining basic domestic needs, the act directed the commission to consider only five residential end uses: (*1*) lighting, (*2*) cooking, (*3*) refrigeration, (*4*) water heating, and (*5*) space heating.[56]

2. North Carolina approved a special rate schedule (a discount for basic monthly energy usage not exceeding 350 kilowatt-hours) for blind, disabled, or aged customers receiving supplemental security income from the Social Security Administration (SSA).[57]

3. Rhode Island approved an experimental residential rate schedule (a 30 percent discount) for all "heads of households" and "principal wage earners" sixty-five years of age or older receiving supplemental security income from the SSA.[58]

4. Montana instituted a four-month "winter" seasonal discount for the first 15 Mcf per month for *all* firm customers. The revenue loss from the discount is made up on Mcf sold in excess of 15 in the winter months and on all Mcf sold in other months, all within the firm class, as follows:

	Winter (January-April)	*Remainder of Year (May-December)*
First 15 Mcf per Month	$2.287 per Mcf	$3.049 per Mcf
Excess of 15 Mcf per Month	$3.049 per Mcf	$3.049 per Mcf[59]

One final consideration: In addition to lifeline rates, many other programs have been tried or instituted to aid those unable to pay rising energy bills.[60] Two pilot projects utilizing energy stamps were undertaken in the mid-1970s, in Lehigh Valley, Pennsylvania, and Denver, Colorado, both funded by the Federal Community Services Administration (formerly the Office of Economic Opportunity). Investment tax credits have been available for homeowners and renters for insulation and other energy conservation devices. Utilities across the country have undertaken various optional conservation programs, including free or low-cost energy audits and low or interest-free loans to customers insulating their homes. Since 1980, Congress has provided a winter heating assistance program to provide aid to individuals receiving supplemental security income and block grants to the fifty states.[61] And many electric and gas utilities have instituted company-customer programs (*i.e.*, HeatShare, EnergyShare, and so forth) to provide funds for those needing assistance, with the funds generally being disbursed by local organizations.

Rate Structures in Practice: Electric Utility Rates[62]

In its early history, most electricity was sold for lighting uses. Electric utilities charged either flat or uniform rates. Under a flat rate, the customer was charged a fixed amount per month or season, irrespective of the quantities of electricity used. (A variant was the fixture rate, which was a fixed amount per month on the basis of the number of lamps or outlets on the customer's premises.[63]) Under a uniform rate, the customer was charged a fixed amount for each kilowatt-hour of electricity used. The former rate encouraged waste because it ignored differences in consumption, while the latter rate ignored demand costs. As the industry developed, recognition of decreasing costs was made by means of progressive discounts for additional use. A customer's bill, to illustrate, might have been discounted 10 percent if fifty kilowatt-hours were used, whereas the discount might have been 20 percent if 100 kilowatt-hours were consumed.[64] Such discounts, of course, were inequitable and were replaced by the step rate. An example of this rate:

50 Kwh or less per month	10¢ per Kwh
50 to 100 Kwh per month	9¢ per Kwh
100 to 150 Kwh per month	8¢ per Kwh
etc.[65]	

An examination of the step rate quickly reveals that it encouraged waste as a user approached a turning point. Thus, forty-eight kilowatt-hours would cost $4.80, but fifty-one kilowatt-hours would cost only $4.59.

Embedded Costs and Traditional Types of Electric Rates

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Electric Rates

f customers (the most

important being residential, commercial, and industrial, as shown in Table 10-4), they established different rates for each class, partly based upon cost differences.

TABLE 10-4

Percentage of Electric Customers, Sales, and Revenues by Customer Classes, 1986

Classification	*Percentage of Customers*	*Percentage of Sales*	*Percentage of Revenues*
Residential & Rural	88.4	34.8	40.0
Commercial	10.8	26.8	29.9
Industrial	.5	34.6	26.7
Other	.3	3.8	3.4
Total	100.0	100.0	100.0

Source: Edison Electric Institute.

Embedded Cost Considerations. The variations in the cost of serving different customers can be illustrated by noting three important technical concepts — the load factor, the utilization factor, and the diversity factor.

The *load factor* is the average load expressed as a percentage of the peak load. Electric utilities are primarily concerned with two types of load curves — annual and customer. Thus, if the average load for a year is 12,000 kilowatts and the peak at any moment of time is 18,000, the annual load factor is 66 2/3 percent. Since electricity cannot be stored, and since a utility must provide instantaneous and uninterrupted service, the size of a utility plant is determined by the amount of service taken by its customers at any particular time (peak period). The peak, it should be noted, may occur only for a short period of time once a year. Utilities attempt to keep their load factor as high as possible, for the higher the average output relative to the peak load, the more units over which to spread the fixed costs. Customers, too, have load factors: the average consumption expressed as a percentage of the maximum consumption. A customer whose average load is high relative to his maximum demand is a more desirable customer than one whose load factor is low.

The *utilization factor* is the peak load expressed as a percentage of the system capacity. Electric utilities must have some reserve capacity to meet emergencies. The necessary reserve will depend on a number of factors, including the size of the area served and the size of the generators and transformers in use. As desirable as a high utilization factor may be, it also serves as a warning to the utility that its excess reserve capacity is declining.[66]

The *diversity factor* is the ratio of the sum of noncoincident maximum demands of a system's customers to maximum demand on the whole system. If all customers registered their maximum demands at exactly the same time, the diversity factor would equal one. But because of differences in time of use, the sum of the noncoincident maximum demands is greater than the system's load at any moment of time — that is, the diversity factor is greater than one. A high diversity factor is desirable, since an electric utility seeks to achieve full utilization on its plant and equipment.

These factors indicate that the cost of supplying electricity to different customers is a function of many variables. Moreover, these factors are interrelated. As Clemens has pointed out,

> . . . a high diversity factor will compensate for low customer load factors. A customer who used only one kilowatt for one hour a day would be an expensive customer. But twenty-four such customers, each using electricity at a different hour, would give the utility a load factor of 100 percent. Conversely, a good load factor customer contributes little to the diversity factor. He uses his equipment continuously and increases the peak load as much as he increases the average load. In short a utility can achieve a desirable load factor for itself by having customers with good load factors, or by a high diversity factor, but either is achieved at the expense of the other.[67]

For ratemaking purposes, electric utilities have historically performed embedded cost-of-service studies. In such studies, it is assumed that an electric utility's total costs are variable. The allocation of these costs among the different classes of customers, however, represents a difficult task since a major portion of total costs are common or joint. The most frequently used division of total costs is a threefold one: (*1*) demand, capacity, or load costs; (*2*) energy, output, or volumetric costs; and (*3*) customer costs.

Demand costs vary with a customer's maximum demand. These costs include investment charges and expenses in connection with generating plants, transmission lines, substations and part of the distribution system. Suppose two customers have equal monthly consumptions but different demands. Customer A has a load of ten kilowatts which he operates 200 hours per month, thus consuming 2,000 kilowatt-hours monthly. Customer B has a load of twenty kilowatts which he operates 100 hours per month, resulting in a monthly use of 2,000 kilowatt-hours or the same as for customer A. The cost of serving B, however, is greater than A's cost, because more equipment is needed to supply the larger load.

Output costs vary with the number of kilowatt-hours consumed and are largely composed of fuel and labor expenses. If customer A uses fifty kilowatt-hours per month and customer B uses 500 kilowatt-hours per month, more fuel and labor will be required to produce the electricity demanded by B than by A.

Customer costs vary with the number of customers. These costs include a portion of the distribution system, local connection facilities, metering equipment, meter reading, billing, and accounting. Customer costs, moreover, are independent of consumption. Assume the monthly consumption of three customers to be ten, fifty, and 500 kilowatt-hours. Despite the differences in consumption, each customer requires a meter, each meter must be read, and a bill must be sent to each customer.

Traditional Types of Electric Rates. The block meter rate or, more precisely, a variation of this type known as the initial charge rate, became the traditional rate schedule for residential and other small users. An example of this rate:

First	12 Kwh per month	$1.75
Next	36 Kwh per month	3.82¢ per Kwh
Next	42 Kwh per month	3.59¢ per Kwh
Next	420 Kwh per month	2.56¢ per Kwh
Next	990 Kwh per month	2.15¢ per Kwh
Excess of	1,500 Kwh per month	1.94¢ per Kwh

Minimum charge: $1.75 per meter per month, exclusive of fuel adjustment.

Under this rate schedule, customer costs are partially recovered by making a flat charge for the first kilowatt-hour block or by making a minimum charge even though nothing is consumed. The demand cost element is recognized only indirectly, however, since it is assumed that demand costs are recovered in the higher earlier blocks. Moreover, the use of the block rate permits the rates in each succeeding block to be lower since only output costs need to be covered. And, from the utility's point of view, the major advantage of this rate schedule is its simplicity, making it easily understood by customers.

The Wright demand rate became common for commercial customers, and at times, for industrial loads. This schedule emphasizes the customer's load factor (demand cost). An example of this rate:

First 100 Kwh per kilowatt of demand per month	6¢ per Kwh
Over 100 Kwh per month	3¢ per Kwh

Under this rate schedule, all customers with the same load factor would pay the same price per kilowatt-hour, regardless of their monthly consumption. As there is no inducement to install additional equipment, the Wright rate is not promotional. Moreover, an examination of the schedule indicates that it contains a hidden demand charge of $3.00 per kilowatt and a uniform energy charge of three cents per kilowatt-hour. Yet, there is no assurance that the full demand cost will be collected by the utility: when a buyer's monthly consumption is less than 100 kilowatt-hours, for example, this would be true.

A two-part Hopkinson demand rate came into use for medium- and large-sized commercial and some industrial customers. This schedule has block demand and block energy charges. An example of the Hopkinson rate schedule:

Demand Charge	
First 50 Kw of demand per month	$2.50 per Kw
Next 100 Kw of demand per month	$2.00 per Kw
Over 150 Kw of demand per month	$1.75 per Kw
Energy Charge	
First 100 Kwh per month	5.5¢ per Kwh
Next 900 Kwh per month	3.0¢ per Kwh
Next 4,000 Kwh per month	2.3¢ per Kwh
Over 5,000 Kwh per month	2.0¢ per Kwh

There are two frequently used ways of measuring a customer's demand. One is to measure with a meter the average consumption during the maximum fifteen- or thirty-minute interval during any three- or six-month period. The second is to compute the total horsepower rating of a customer's connected equipment.

In actual practice, industrial rate schedules are more complex, as indicated in Table 10-5. There may be a service charge, making a three-part rate. Off-peak service may be offered at a lower rate than is charged for peak service. Utilities may have a uniform rate for each kilowatt of demand instead of block demand rates. Monthly minimums are common. Discounts may be given for payment of bills within a specified number of days, with an additional charge if bills are not paid within the time limit. Other discounts may be given to industrial buyers who own transformers (voltage discount) or who purchase electricity at the supply-line voltage. When a customer requires additional voltage regulation (power factor), a special charge may be made.[68] A fuel cost adjustment has long been used to permit a utility to follow the variations in fuel costs either upward or downward. "The special provisions of industrial price schedules (*e.g.*, power factor adjust-

TABLE 10-5

Illustrative Industrial Power Schedule

Availability

Available in the entire territory of the company for any purpose for single-phase and three-phase loads of 50 kilowatts or more.

Monthly Rate

Demand charge:

First 50 Kw @ $2.50 gross per Kw of billing demand
Next 100 Kw @ $2.00 gross per Kw of billing demand
Additional @ $1.75 gross per Kw of billing demand

Voltage discount:

20 cents per kilowatt when the service voltage is 22 kilovolts.

Power factor charge:

25 cents gross per reactive kilovolt-ampere in excess of 50 per cent of the kilowatt demand. The reactive kilovolt-ampere demand shall be determined in the same way as the kilowatt demand.

Energy charge:

First 25,000 Kwh @ 10.0¢ gross per Kwh
Additional @ 0.8¢ gross per Kwh

Fuel cost adjustment:

Increase or decrease of 0.01 cent gross per kilowatt-hour for each change of 0.50 cents per million Btu above or below 15 cents per million Btu for the average cost of fuel on hand and delivered at company's generating stations during the second calendar month preceding the billing date.

Prompt payment discount:

2 per cent for payment within ten days.

Determination of Billing Demand

The billing demand for any month shall be the highest of the following:

1. The kilowatt demand, which shall be the maximum 15-minute kilowatt demand of the on-peak period plus 50 per cent of the excess of the maximum 15-minute kilowatt demand of the off-peak period over the on-peak demand.
2. 50 per cent of the maximum kilowatt demand of the preceding 11 months.
3. 50 kilowatts.

The off-peak period shall be from 10 P.M. until 6 A.M. daily, and from 12 noon Saturday until 6 A.M. Monday.

Term

Minimum of one year.

Source: Russell E. Caywood, *Electric Utility Rate Economics* (New York: McGraw-Hill Book Co., Inc., 1956), p. 66. Used by permission of McGraw-Hill Book Company.

ments) show distinctly the influence of the engineer in the formulation of pricing practices. Because engineers influence the shape of these schedules, only an engineer, indeed, can interpret and apply their technical provisions."[69]

Discrimination in Practice. The above typical electric utility rate schedules are highly differentiated and discriminatory. Such discrimination occurred in at least three ways. First, there are many different block sizes and block rates which could have been chosen. In determining these sizes and rates, both cost and demand considerations were taken into account. If a utility tried to recover its total demand and customer costs in the first block, the initial block rate might be so high that it would discourage more consumption. These costs were thus spread throughout succeeding blocks, largely according to differences in elasticities of demand. Explains Wilcox:

> Big industrial users have the alternative of generating their own power; their demand, therefore, is highly elastic; their rates are low. Other users lack this alternative; their demand is less elastic; their rates are higher. Householders can use gas rather than electricity for cooking; for this purpose their demand is elastic; the additional kilowatt-hours used in cooking fall in the quantity blocks where rates are low. Householders, on the other hand, are unlikely to substitute gas, kerosene, or candles for electricity in lighting; their demand for this purpose is inelastic; the hours used in lighting fall in the first block where rates are high.[70]

Consequently, both block sizes and block rates were established by the utility companies on the basis of differences in the value of service for each class of customer.

The second way in which discrimination is evident in the above electric utility rate structures is that allocation of demand, output, and customer costs among the different classes of customers is largely arbitrary. Particularly is this true of demand costs, "the treatment of which has made a nightmare of utility cost analysis. For the problem which it presents is that of imputing joint costs to joint products or byproducts and not merely that of distributing those common but nonjoint costs which vary more or less continuously with number of customers or with rates of output."[71]

In his book on electric rates, Caywood discusses three formulas for allocating demand costs among different classes of customers.[72] (*1*) The "peak responsibility method." Under this formula, the entire demand costs are allocated to those services rendered at the time of the system's peak demand, in proportion to the kilowatt demand at this peak load. Service rendered off-peak would not be apportioned demand costs. (*2*) The "noncoincident demand method." Here, demand costs are allocated among services in proportion to the maximum demands of the various classes regardless of when each class's maximum demand occurs. (*3*) The "average and excess demand method." Under this method,

> . . . the assumed cost of that portion of the company's plant capacity which would be needed even if all consumers were taking their power at 100 per cent load factor is apportioned among customers in proportion to their average loads. . . . But the assumed cost of the excess in actual plant capacity over this lower, hypothetical capacity is apportioned "by applying the noncoincident peak method to the difference between maximum loads and average loads."[73]

The three methods lead to quite different results. Assuming three class loads comprising a system load having a peak of 1,000 kilowatts (Figure 10-1), the results are shown in Table 10-6.

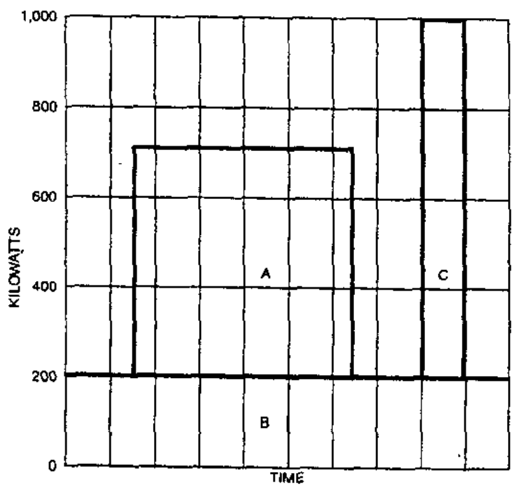
For many years, the most frequently used means of allocating demand costs was the second method — the noncoincident demand method. Three steps are involved. An aggregate maximum demand is obtained by adding together the separate maximum demands of all classes of customers. Then, the percentage of this aggregate that is attributable to each class is determined. Finally, demand costs are allocated to each class in accordance with these percentages. The noncoincident demand method, despite its widespread use, is based upon two fallacies and, in fact, is not really a cost analysis at all. As Wilcox succinctly states:

> First, it involves circular reasoning. The differences in demand that are used as a guide in allocating costs are not independent of differences in rates, but are themselves determined by these differences. The companies first fix the rates they want to charge. These rates, in turn, affect the quantities demanded. These quantities are then used to govern the distribution of costs. And the costs are presented, finally, to justify the rates. Q.E.D. Second, the method does not make proper allowance for the factor of diversity. The concept of maximum coincident demand for a utility system as a whole is meaningful. The concept of aggregate noncoincident maximum demands of customer classes is not. A company does have to build a plant big enough to meet the peak of coincident demand. It does not have to build one big enough to meet the aggregate of noncoincident demands. For such demands, by definition, occur at different times. If a customer's maximum comes at the same time as the system's maximum, he may properly be charged with more responsibility for the size of the investment that is required. If it comes at any other time, he should be charged with less. But how much more and how much less is open to debate.[74]

Perhaps no formula of apportionment is perfect. Bonbright has argued, however, that from the standpoint of cost analysis, the "peak responsibility method" would undoubtedly come the closest to receiving support from economists. He points out two major difficulties in using the formula. In the first place, as the periods of peak demand are subject to constant

FIGURE 10-1

Hypothetical Loads



Source: Russell E. Caywood, *Electric Utility Rate Economics* (New York: McGraw-Hill Book Co., Inc., 1956), p. 162. Used by permission of McGraw-Hill Book Company.

TABLE 10-6

Results of Demand Allocation Formulas*

Load	*Maximum Demand*	*Load Factor*	*Allocation* PR Method	NCD Method	AED Method
A	500 Kw	50%	0 Kw	333 Kw	371 Kw
B	200	100	200	133	200
C	800	10	800	534	429
	1,500 Kw		1,000 Kw	1,000 Kw	1,000 Kw

*Assumption: Three classes of loads comprising a system load having a peak demand of 1,000 kilowatts.

Source: Russell E. Caywood, *Electric Utility Rate Economics* (New York: McGraw-Hill Book Co., Inc., 1956), p. 163. Used by permission of McGraw-Hill Book Company.

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change, apportionment on this basis would necessitate frequent changes in the structure of rates. Such changes may have disruptive effects on consumption. But if the system's annual peak were used and if changes were announced in advance and at stated intervals, gradual adjustments in rates could overcome this difficulty. More important is a second often-voiced objection that the utility plant is required for the service of both on-peak and off-peak users and that both, therefore, should make some contribution toward its capital cost.[75] Once again, the question of how much must be raised.[76]

Closely connected is a third way in which discrimination enters into the rate structures: rates within each class do not vary according to time of use. (There are certain exceptions. Rates did vary by time of use for some large industrial customers; in a few instances, they varied for residential water heating; and, in even fewer instances, for residential space heating.) It was previously pointed out that the size of a utility plant and, hence, the total investment in the business, is determined by the quantity of service it must render during periods of peak demand. Just as in the case of apportioning total demand costs among classes, customers within each class who use the service during peak demand periods should contribute a larger percentage toward the class's share of the capital costs than should off-peak users. As there is no attempt to separate those two groups of customers, the rate schedule discriminates against those who use the service in off-peak hours.

Marginal (Incremental) Costs and Recent Trends

A fundamental shift in rate design philosophy began to occur in the late 1960s. Inflation, rising fuel prices, and environmental concerns were the major factors accounting for the shift, with enactment of the Public Utility Regulatory Policies Act (in 1978) and the emergence of surplus capacity (in the 1980s) added factors. Two changes occurred almost immediately. First, automatic fuel adjustment clauses were included in electric tariffs; by 1977, all but six states had adopted such clauses.[77] Second, summer-winter differentials gained widespread acceptance. The following residential (general service) rate schedule is illustrative:

		June to September	*October to May*
First	12 Kwh per month..	$1.75	$1.75
Next	36 Kwh per month..	3.82¢ per Kwh	3.82¢ per Kwh
Next	42 Kwh per month..	3.59¢ per Kwh	3.59¢ per Kwh
Next	420 Kwh per month..	2.56¢ per Kwh	3.56¢ per Kwh
Next	990 Kwh per month..	2.36¢ per Kwh	2.15¢ per Kwh
Excess of	1,500 Kwh per month..	2.36¢ per Kwh	1.94¢ per Kwh

Minimum charge: $1.75 per meter per month, exclusive of fuel adjustment.

For summer peaking utilities, the use of a summer-winter differential reflects the higher costs of adding capacity to serve the summer load (peak). Further, as rates continued to rise, blocks were gradually eliminated and inverted summer rates were introduced. Consider the following rate structure, which represents a later refinement of the above structure.

	June to September	*October to May*
Customer Charge	$5.60 per month	$5.60 per month
First 800 Kwh per month	6.622¢ per Kwh	6.622¢ per Kwh
Excess of 800 Kwh per month	7.439¢ per Kwh	5.124¢ per Kwh[78]

It is important to emphasize, however, that these rate structures were still based upon an embedded cost-of-service philosophy.

Incremental Cost Pricing. The long-run incremental cost (LRIC) concept has gained increased recognition in rate proceedings. This concept, unlike the concept of marginal cost, recognizes that electric utilities add capacity in discrete units and on a continuous basis. The long-run incremental cost concept thus includes the future costs of supplying electricity, as opposed to the traditional philosophy of basing rates on past or embedded costs of serving customers.

With respect to residential rates and based upon its analysis of long-run incremental cost, the Wisconsin commission in 1974 abandoned the traditional declining block rate structure, substituting an essentially flat rate for energy (and a fixed customer charge, which did not recover all customer-related costs) and instituted a summer-winter differential. The commission established the following rate structure, as compared to the structure authorized in a 1970 decision:[79]

	1970 Rates	*New Rates*	
Residential (rg-1)		*Winter*	*Summer*
Fixed Charge	$ .75	$1.50	$1.50
First 100 Kwh per month ..	2.85¢	2.50¢	2.50¢
Next 400 Kwh per month ..	2.03¢	2.20¢	2.20¢
Next 500 Kwh per month ..	2.03¢	2.20¢	2.20¢
Next 500 Kwh per month ..	1.56¢	2.20¢	2.20¢
Over 1,500 Kwh per month ..	1.56¢	1.50¢	2.20¢

In commenting on the new rate structure, Commissioner Cudahy noted:

> . . . the economic evidence (insofar as it points to a definite movement away from "decreasing" costs) offers substantial support to the concept of flat rates as a starting point, bearing some presumption of reasonableness. But I am persuaded that each class and subclass of customers must also be analyzed on its own merits (with particular emphasis on contribution to annual — or, if applicable, seasonal —

peaks). For purposes of efficient blocking the essential question is whether additional usage results in lower or higher per kilowatt-hour costs. As a simplistic matter (and this is one of the arguments advanced for declining-block rates), it would appear that spreading additional usage over the same fixed costs would produce lower average costs. An important facet of this concept is illustrated by current utility distress over loss of revenues due to conservation. This line of reasoning seems to be correct in the case of "customer" costs, but beyond that it reflects only *short-run* considerations and is valid *in the long run* only if contribution to annual or seasonal (cost-causing) peaks is less than directly proportional to the corresponding increase in usage.

In the case of the summer residential rate we have assumed that increased usage (containing air conditioning) contributes at least proportionately to the annual (temperature-sensitive) peak. We have thus, after recovery of customer costs (in the fixed charge and in the first block), constructed a flat rate. No doubt this approach incorporates only a rough tracking of costs through the rate blocks. But with current metering techniques, these seem to be the best cost approximations which can be achieved. . . .[80]

Finally, the Wisconsin commission recognized 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 use cannot be postponed until winter.[81]

Since the *Madison Gas and Electric* decision, incremental cost studies have been submitted in countless rate cases, experimental (or demonstration) time-of-day projects have been undertaken by a number of electric utilities, and time-of-day rates have been put into effect for industrial and commercial customers, as well as for some large residential customers (see Table 10-7). Based upon an analysis of 34 state commissions, Weiss concludes:

By early 1980 at least eight states were explicitly using some sort of marginal-cost or incremental-cost concepts in setting rates. These are Arizona, California, Michigan, New York, Ohio, Oregon, Vermont, and Wisconsin. In estimating incremental costs, all of these states use present or future costs to estimate the investments in plant and equipment. Most state commissions have seasonal rates for both industrial and residential customers, but some of these go back many years. A majority of

TABLE 10-7

Experimental Time-of-day Residential Rate Structure

	June to September	*October to May*
Customer Charge	$11.00 per month	$11.00 per month
Demand Charge		
Onpeak Kw of demand ...	$ 3.28 per Kw	$ 2.68 per Kw
Energy Charge		
Onpeak per Kwh	4.429¢ per Kwh	3.691¢ per Kwh
Offpeak per Kwh	2.760¢ per Kwh	2.760¢ per Kwh

Demand Charge: The highest average kilowatt load measured in any 30-minute interval during the onpeak hours of the current month.

Onpeak Hours: 10 A.M. to 10 P.M., EDT (9 A.M. to 9 P.M., EST), Mondays through Fridays.

Source: Virginia Electric and Power Company (1980).

states have time-of-day rates for industrial customers, and Arkansas, Michigan, Ohio, Oregon, Pennsylvania, Texas, and Wisconsin base industrial-demand charges on demand at system peak rather than at customer peak. Seventeen states have some residential time-of-day rates, but most of these were experimental or optional. Some of the experiments have used sophisticated statistical techniques. The findings to date are that consumers do respond to seasonal and time-of-day rate differences, but it still is not clear that the gains are worth the cost of the more elaborate metering required.[82]

PURPA and Further Rate Reform. In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA), as part of the national energy plan.[83] That act required the state commissions to consider, and to implement or adopt if appropriate, six ratemaking standards[84] and five regulatory standards for electric utilities to further three statutory purposes: end-use conservation, utility efficiency, and equitable rates. The ratemaking standards, contained in Section III, in summary form, are:

1. Cost of service — the rates for each class of customer shall be designed, to the maximum extent practicable, to reflect the cost of providing service to that class. Section 115 (a) provides that costs shall be "determined on the basis of methods prescribed by the state and regulatory authority."

2. Declining block rates — the *energy* component of a rate for any class of service may not decrease as consumption increases unless the utility demonstrates that those energy costs in fact decrease as consumption increases.
3. Time-of-day rates — the rates for each class of service shall be on a time-of-day basis which reflects the cost of providing service at different times of day unless such rates are not cost effective for that class.
4. Seasonal rates — rates charged for the provision of service to each class of customer shall be on a seasonal basis which reflects the costs of providing such service to each class of consumer at different seasons to the extent that costs vary seasonally for the utility.
5. Interruptible rates — each utility shall offer industrial and commercial customers interruptible rates which reflect the cost of providing such service.
6. Load management techniques — each utility shall offer to its customers load management techniques where (a) practicable and cost effective, (b) reliable, and (c) useful to the utility for energy or capacity management.[85]

The act provided that the state commissions should consider and implement these ratemaking standards, if appropriate, within three years (*i.e.*, by November, 1981). The Department of Energy was given authority to intervene in any state proceeding related to rate design and to appeal the resulting decision in the courts. Various technical (*e.g.*, load management techniques, methods for determining cost of service) and financial assistance was provided to state commissions. Finally, funding was authorized for two programs established by the Energy Conservation and Production Act of 1976: grants to state offices of consumer services to assist consumers in making presentations before state commissions and grants to fund development of innovative rate structures.

A full assessment of these aspects of PURPA will take some time, although most of the state commissions have already adopted and/or implemented one or more of the standards.[86]

Competition and Surplus Capacity: Some Unresolved Issues. There are three additional pricing issues that remain unresolved, yet are of significance as competition and surplus capacity evolve in the industry. First, there are "wheeling" rates; rates for transporting electric energy from a seller of power to a buyer over the transmission lines of one or more utilities and/or government entities.[87] The demand for transmission services has grown in recent years, due in part to expanded sales of economy energy,[88] but also due to the development of surplus capacity (*e.g.*, large wholesale and retail customers desire to "shop around" for low-priced power) and to the growth of nonutility-owned cogeneration and small power production (discussed below). Greater transmission access, some argue, would remove a major impediment to increased competition in bulk power markets and, possibly, enhance generation deregulation.[89] But too often, they contend, wheeling is not economically feasible because of high wheeling rates.[90] While there are a variety of wheeling rate schedules,

> . . . the most common is a "postage stamp rate" under which a customer is charged a fixed rate per unit of service; *e.g.*, miles per kilowatt-hour for nonfirm wheeling or dollars per kilowatt for firm wheeling. In approving rates for firm power wheeling, the FERC has employed an (embedded) "rolled-in" costing methodology; *i.e.*, all transmission-related costs are aggregated and uniformally allocated to firm transmission customers based on their respective demand. The commission has also approved numerous transmission rate schedules utilizing the costs of specific transmission facilities where it can be argued that those facilities are the principal ones employed in providing the service. . . .[91]

Second, there is the problem of the "full avoided cost rule." Title II of the Public Utility Regulatory Policies Act encouraged both cogeneration and small power production. The former "is the combined production of electrical power and useful thermal energy, such as heat or steam."[92] The latter are those producers which use biomass, waste, geothermal resources, or renewable resources (such as wind, solar energy, and water) to produce electric power and whose power production capacity is no greater than eighty megawatts.[93] Plants meeting PURPA requirements are termed "qualifying facilities" (QFs). Their encouragement has come from a requirement in the act (Section 210) that electric utilities purchase power produced from such facilities at their full avoided costs, defined by the FERC as "the incremental costs to an electric utility of electric energy, or capacity, or both which, but for the purchase from the qualifying facility or qualifying facilities, such a utility would generate itself or purchase from another source."[94]

To date, the states have not adopted a uniform calculation of avoided costs.[95] Moreover, the issue has become even more complex with the emergence of surplus capacity. A district court, for example, has ruled that PURPA does not require electric utilities to purchase power from QFs at a higher than market price.[96] And one state commission has approved "anticogeneration" rate contracts.[97]

Third, there are special discount rates; rates that have been proposed and adopted (often on an experimental basis) that are commonly known as "incentive" or "economic development" rates. Such rates "are designed both to promote increased sales to existing industrial customers and to attract new firms to a utility's service territory" and "are advanced as a means for lowering the short-run average total cost of an electric utility (and thereby the rates for all customer classes) as well as being more in line with efficient pricing in view of today's market conditions."[98] Such rates, however, raise issues of undue discrimination, from a statutory standpoint (*e.g.*, they are offered to only one class of customers), although they are based upon short-run marginal or long-run incremental costs. Three state commission decisions are typical:

1. In approving a discounted industrial rate (on a two-year experimental basis), the Rhode Island commission noted that the company's marginal costs were below its average embedded costs. While the proposed rate was discriminatory, it was in the "interest of the public," since its purpose was "to stimulate the local economy and provide new jobs" for the state, by being "attractive to growing New England companies who currently consider Rhode Island to be 'invisible.'"[99]

2. In approving a proposal for an "economic redevelopment" tariff, the Michigan commission agreed that the proposal resulted "in a form of discrimination." However, the rate was "designed to accomplish a rational purpose which includes encouraging minimum consumption, increasing manufacturing activity, increasing employment, and securing revenues to cover the utility's fixed costs. Furthermore, by increasing such business activity, the economic redevelopment rate will contribute to the eradication of the dismal economic climate in certain portions of the applicant's service territory within the state of Michigan."[100]

3. In approving a "special industrial contract policy," the New Hampshire commission concluded that as long as "an incremental customer pays a price that is above marginal cost, he is sharing the fixed costs with the company's nonincremental customers, thus reducing the responsibility of the nonincremental customer to pay those fixed costs."[101]

Notes

*Abba P. Lerner, "Conflicting Principles of Public Utility Price Regulation," 7 *Journal of Law and Economics* 61 (1964).

[1]Alfred E. Kahn, *The Economics of Regulation* (New York: John Wiley & Sons, Inc., 1970), Vol. I, p. 64.

[2]The water industry is considered in Chapter 16.

[3]James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), p. 291. See also Russell E. Caywood, "Electric Utility Rate Making Today," 81 *Public Utilities Fortnightly* 51, 53-54 (June 6, 1968).

[4]For an excellent analysis of this issue, see Edward E. Zajac, *Fairness or Efficiency: An Introduction to Public Utility Pricing* (Cambridge: Ballinger Publishing Co., 1978).

[5]Bonbright, *op. cit.*

[6]*Ibid.*, p. 292. See also John M. Clark, *Studies in the Economics of Overhead Costs* (Chicago: University of Chicago Press, 1932), p. 322.

[7]The content and outline of the first two sections closely follow Clair Wilcox, *Public Policies Toward Business* (4th ed.; Homewood, Ill.: Richard D. Irwin, Inc., 1971), pp. 321-27, and are used with the late author's permission.

[8]See Chapter 6, pp. 215-18. In discussing the problem of cost allocation for railroad service, Hadley once remarked that "God Almighty did not know the cost of carrying a hundred pounds of freight from Boston to New York." Quoted by Winthrop M. Daniels, *The Price of Transportation* (New York: Harper & Bros., 1932), p. 48.

[9]I. Leo Sharfman, *The Interstate Commerce Commission* (New York: Commonwealth Fund, 1936), Vol. IIIB, pp. 321-22.

[10]This statement does not imply that price discrimination is unimportant in the nonregulated sector of the economy. When competition is imperfect and when sellers lack complete information about each product, discrimination may occur.

[11]George J. Stigler, *The Theory of Price* (3d ed.; New York: The Macmillan Co., 1966), p. 210.

[12]Assuming decreasing costs, there is an additional justification for discrimination. Marginal cost pricing would result in losses, since marginal cost is below average cost. The most obvious solution — a subsidy to make up the difference between marginal and average cost — is not an option available to regulatory commissions, and no legislative body has ever indicated a willingness to pay such a subsidy.

[13]*Re Generic Hearings Concerning Electric Rate Structure*, 36 PUR4th 6, 50 (Colo., 1979) (footnote omitted).

[14]Alfred E. Kahn, "Efficient Rate Design: The Transition from Theory to Practice," in *Proceedings of the Symposium on Rate Design Problems of Regulated Industries* (Columbia: University of Missouri-Columbia, 1975), p. 35.

[15]If entry were permitted, competitors would enter into those markets where rates are above marginal costs; a situation frequently referred to as "cream-skimming." For an analysis of the issue, see Kahn, *The Economics of Regulation, op. cit.*, Vol. II (1971), pp. 220-50. See also Alan Reynolds, "A Kind Word for 'Cream Skimming,'" 52 *Harvard Business Review* 113 (November-December, 1974).

[16]See Nancy Ruggles, "The Welfare Basis of the Marginal Cost Pricing Principle," 17 *Review of Economic Studies* 29 (1949-50) and "Recent Developments in the Theory of Marginal Cost Pricing," 17 *Review of Economic Studies* 107 (1949-50).

[17]The classic article is by Harold Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," 6 *Econometrica* 242 (1938). See also William S. Vickrey, "Some Implications of Marginal Cost Pricing for Public Utilities," 45 *American Economic Review* 605 (Papers and Proceedings, 1955).

[18]Since the mid-1950s, the Electricite de France, a public electric power system, has used the principle as a basis of setting rates and for investment policy. See Thomas Marschak, "Capital Budgeting and Pricing in the French Nationalized Industries," 33 *Journal of Business of the University of Chicago* 133 (1960); James R. Nelson, "Practical Applications of Marginal Cost Pricing in the Public Utility Field," 53 *American Economic Review* 474 (1963); Ronald L. Meek, "An Application of Marginal Cost Pricing: The 'Green Tariff' in Theory and Practice," Part I, "The Theory," 11 *Journal of Industrial Economics* 217 (1963), Part II, "The Practice," 12 *Journal of Industrial Economics* 45 (1963); Marcel Boiteux, "The Green Tariff of the Electricite de France," as translated by Eli W. Clemens and Lucienne C. Clemens, 40 *Land Economics* 185

(1964); Eli W. Clemens, "Marginal Cost Pricing: A Comparison of French and American Industrial Power Rates," 40 *Land Economics* 389 (1964); James R. Nelson (ed.), *Marginal Cost Pricing in Practice* (Englewood Cliffs: Prentice-Hall, Inc., 1964). Recent developments are discussed by Hans E. Nissel, "Electricite de France Revises Its Green Tariff," 108 *Public Utilities Fortnightly* 22 (July 30, 1981). In England, a Bulk Supply Tariff, based on the marginal cost pricing concept, was put into use in 1967. See Haskell P. Wald, "The Theory of Marginal Cost Pricing and Utility Rates," 79 *Public Utilities Fortnightly* 15, 23-24 (June 22, 1967).

[19]Kahn, "Efficient Rate Design . . .," *op. cit.*, p. 35.

[20]R. G. Lipsey and K. J. Lancaster, "The General Theory of the Second Best," 24 *Review of Economic Studies* 11 (1956-57). But see E. J. Mishan, "Second Thoughts on Second Best," 14 *Oxford Economic Papers* 205 (1962).

[21]Kahn, *The Economics of Regulation, op. cit.*, Vol. I, p. 69.

[22]William J. Baumol, *Welfare Economics and the Theory of the State* (2d ed.; Cambridge: Harvard University Press, 1965), p. 30. See also M. J. Ferrell, "In Defense of Public-Utility Price Theory," 10 *Oxford Economic Papers* 112 (1958); J. Wiseman, "The Theory of Public Utility Price: A Further Note," 11 *Oxford Economic Papers* 92 (1959); Otto A. Davis and Andrew B. Whinston, "Welfare Economics and the Theory of Second Best," 32 *Review of Economic Studies* 1 (1965); R. Dusansky and J. Walsh, "Separability, Welfare Economics and the Theory of Second Best," 43 *Review of Economic Studies* 49 (1976); T. Hatta, "A Theory of Piecemeal Policy Recommendations," 44 *Review of Economic Studies* 1 (1977); K. Kawamata, "Price Distortion and the Second Best Optimum," 44 *Review of Economic Studies* 23 (1977).

[23]Stigler, *op. cit.*, chaps. v-x.

[24]Kahn, "Efficient Rate Design . . .," *op. cit.*, p. 38.

[25]*Re Madison Gas & Elec. Co.*, 5 PUR4th 28, 35-36 (Wis., 1974).

[26]Kahn, "Efficient Rate Design . . ., *op. cit.*, p. 39.

[27]William H. Melody, "The Marginal Utility of Marginal Analysis in Public Policy Formulation," 8 *Journal of Economic Issues* 287, 295 (1974). See also Joseph M. Cleary, "Marginland: A Magic Place Where Costs Disappear," 112 *Public Utilities Fortnightly* 23 (July 21, 1983).

[28]For a summary, see Ernst & Whinney, "An Evaluation of Ten Marginal Costing Methodologies" (A Report Prepared for the Electricity Consumers Resource Council, August 1979). For an analysis of the Cicchetti, Gillen, Smolensky (CGS) approach, see Charles J. Cicchetti and William J. Gillen, *The Marginal Cost and Pricing of Electricity* (Cambridge: Ballinger Publishing Co., 1977). Similarly, for an analysis of the National Economic Research Associates (NERA) approach, see three reports prepared for the Electric Utility Rate Design Study: "A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3" (February 1977), "How to Quantify Marginal Costs: Topic 4" (March 1977), and "Ratemaking: Topic 5" (June 1977).

[29]Gregory Crespi, "Marginal Cost-of-Service Studies: Some Practical Difficulties," 106 *Public Utilities Fortnightly* 19, 21 (December 4, 1980).

[30]See William J. Baumol and David F. Bradford, "Optimal Departures from Marginal Cost Pricing," 60 *American Economic Review* 265 (1970).

[31]Leonard W. Weiss, "State Regulation of Public Utilities and Marginal-cost Pricing," in Leonard W. Weiss and Michael W. Klass (eds.), *Case Studies in Regulation: Revolution and Reform* (Boston: Little, Brown and Co., 1981), p. 273.

[32]Both the California and New York commissions have held that customer costs

should be excluded from marginal cost calculations. See *Re Pacific Gas & Elec. Co.*, 34 PUR4th 1, 64-65 (Cal., 1979); *Re Consolidated Edison Co. of New York, Inc.*, 29 PUR4th 284, 291 (N.Y., 1979).

[33]Department of Energy, "Voluntary Guideline for the Cost of Service Standard under the Public Utility Regulatory Policies Act of 1978; Proposed Guideline and Public Hearing," 45 *Fed. Reg.* 58760, 58767 (September 4, 1980).

[34]*Ibid.*

[35]As the New York commission has put it: "The application of marginal cost pricing principles to electric rates would require peak-load pricing, since the cost of supplying additional consumption ordinarily varies (whether little or much need not concern us at this point) by the time of day and season of the year. If we adopt the former, we must be prepared to adopt the latter. The converse, however, is not true: the case for rates varying with time of consumption is not dependent on the case for marginal cost pricing; it is possible to justify and base time-related rates on average costs, embedded costs, fully allocated costs, as well as marginal." *Re Determining Relevance of Marginal Costs to Electric Rate Structures*, Case No. 26806 (N.Y., 1976).

[36]Hans E. Nissel, "Federal Rate Design Standards and Energy Conservation," 103 *Public Utilities Fortnightly* 16, 24 (May 24, 1979). See also, by the same author, "Peak-load Pricing, Facts and Fancy," 106 *Public Utilities Fortnightly* 17 (September 11, 1960).

The relatively long peak periods arise from the fact that it would be impossible to establish a rate structure that tracked costs hour-by-hour and day-by-day. Thus, for ratemaking purposes, costs are grouped into "rating periods," and an average of these costs used within those periods.

[37]Jan Paul Acton and Bridger M. Mitchell, "The Effect of Time-of-use Rates: Facts versus Opinions," 107 *Public Utilities Fortnightly* 19 (April 23, 1981).

[38]Bonbright, *op. cit.*, p. 317, n. 2.

[39]*Ibid.*, p. 332.

[40]*Ibid.*, p. 333.

[41]See William J. Baumol and Associates, "The Role of Cost in the Minimum Pricing of Railroad Services," 35 *Journal of Business of the University of Chicago* 357, 361-62 (1962).

[42]"For maximum economic efficiency, rates should be related to costs, but not to an arbitrary allocation of costs. . . . 'Cost-oriented rates' in the true economic sense are related to the economist's concept of marginal cost — the increase in total expenses as a result of carrying additional ton-miles of traffic. In order to ensure efficiency, marginal, rather than average, cost should be the principal regulatory criterion in applications for rate reductions. . . . [W]here competition and new technology dictate rate reductions, competitive rates could be lowered to the level of marginal cost." "Annual Report of the Council of Economic Advisers" in *Economic Report of the President* (Washington, D.C.: U.S. Government Printing Office, 1966), p. 127.

[43]Baumol and Associates, *op. cit.*, p. 362. See also John J. Coyle, "Dissimilar Pricing: A Logical Approach to Regulated Rates," 78 *Public Utilities Fortnightly* 32 (September 15, 1966); James C. Nelson, "Economic Standards for Competitive Freight Rates," 48 *Journal of Farm Economics* 1408 (1966); Irwin M. Stelzer, "Incremental Costs and Utility Rate-Making in the Competitive Era," American Bar Association Annual Report, Section of *Public Utility Law, 1967*, pp. 26-42; Haskell P. Wald, "The Theory of Marginal Cost Pricing and Utility Rates," 79 *Public Utilities Fortnightly* 15

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(June 22, 1967); Ronald H. Coase, "The Theory of Public Utility Pricing and its Application," 1 *Bell Journal of Economics & Management Science* 113 (1970).

[44]See, *e.g.*, the famous "Big John" case: *Grain in Multiple-Car Shipments — River Crossings to the South*, I&S Docket No. 7656 (January 21, 1963) and 321 ICC 582 (July 1, 1963), *rev'd sub nom. Cincinnati, New Orleans, & Texas Pacific Ry. Co. v. United States*, 229 F. Supp. 572 (1964), *vacated and remanded sub nom. Arrow Transportation Co. v. Cincinnati, New Orleans & Texas Pacific Ry. Co.*, 379 U.S. 642 (1965), final commission decision, 325 ICC 752 (1965).

[45]*Re Rate Design for Electric Corporations*, 26 PUR4th 280, 285 (N.Y., 1978).

[46]See, *e.g.*, "Moving toward Lifeline Rates," 101 *Public Utilities Fortnightly* 54 (June 22, 1978); "The Lifeline Rate Issue," 104 *Public Utilities Fortnightly* 42 (October 11, 1979); "Telephone Lifeline Rates After the AT&T Divestiture," 117 *Public Utilities Fortnightly* 57 (June 12, 1986).

[47]This was the position taken by the New Hampshire commission and by the Oregon commissioner: *Re Public Service Co. of N.H.*, 95 PUR3d 401 (N.H., 1972); *Re Rate Concessions to Poor Persons and Senior Citizens*, 14 PUR4th 87 (Or., 1976) and *Re Investigation into Rate Structures of Electric Utilities*, 38 PUR4th 409 (Or., 1980). But see *Re Montana-Dakota Utilities Co.*, 21 PUR4th 1 (S.D., 1977); *Re Telephone Lifeline Rates*, 72 PUR4th 407 (Utah, 1986). In California, the legislature mandated lifeline rates for residential electric and gas customers under the Miller-Warren Energy Lifeline Act of 1975 and for telephone subscribers under the Moore Universal Telephone Service Act of 1984; and in Michigan, residential lifeline rates for electricity were mandated by a 1980 amendment to the Public Service Commission Act [see *Re Lifeline Rates*, 42 PUR4th 432 (Mich., 1981). The act was repealed in 1984. See *Re Detroit Edison Co.*, 81 PUR4th 144 (Mich., 1987)]. In Maine, the legislature rejected the lifeline concept in 1977. For an argument that energy conservation and appropriate programs for public assistance to those truly eligible are preferable to lifeline rates, see J. B. Roll and Ellen Beth Lande, "Lifeline Rates: Impact and Significance," 106 *Public Utilities Fortnightly* 13 (July 31, 1980); H. Craig Petersen, "Gainers and Losers with Lifeline Electricity Rates," 110 *Public Utilities Fortnightly* 33 (November 25, 1982).

[48]Section 114 of the act.

[49]See, *e.g.*, *Re New England Teleph. & Teleg. Co.*, 84 PUR3d 130 (Mass., 1970); *Re New England Teleph. & Teleg. Co.*, 89 PUR3d 417 (R.I., 1971); *Pennsylvania Pub. Utility Comm. v. Philadelphia Elec. Co.*, 91 PUR3d 321 (Pa., 1971); *Mountain States Legal Foundation v. Colorado Pub. Utilities Comm.*, 28 PUR4th 609 (1979). It also has been held that undue discrimination occurs when rates are based upon ability to pay [*Re Washington Gas Light Co.*, Order No. 5542 (D.C., 1972)], unless a commission is directed to do so by the legislature [*Re Interstate Residential Subscriber Line Charge Waiver Mechanism*, Docket No. P-100, Sub 80 (N.C., 1986)].

[50]One study concluded that "the minimum use customer is likely to be the relatively affluent, middle-aged apartment or condominium dweller who uses his residence only part of the year, who eats out frequently, and who finds much of his entertainment away from home." Thus, a lifeline rate in New York might well result in the poor and elderly "subsidizing the affluent." Statement of Jules Joskow, speech before the Southeastern Association of Regulatory Utility Commissioners, as summarized in 96 *Public Utilities Fortnightly* 34 (May 8, 1975). Concluded the New York commission, after an extensive generic investigation: "... the relationship between

electricity consumption and income is far more complex than the lifeline proponents assumed." *Re Rate Design for Electric Corporations*, *op. cit.*, p. 293.

[51]*Re Investigation into Rate Structures of Electric Utilities*, *op. cit.*, p. 412. In that case, a Pacific Power and Light witness testified that "on average, individual electric consumption varies by 275 kilowatt-hours from month to month." *Ibid.* In the mid-1970s, to further illustrate the problem, a lifeline bill introduced in the Massachusetts legislature provided for an initial block of 300 kilowatt-hours per month (for residential customers), while a similar bill introduced in the Florida legislature provided for an initial block of 700 kilowatt-hours per month. In 1980, the Washington commission found that "the level of electric service meeting 'essential needs' falls in a range of approximately 400 to 600 kwh per month." *Re Pacific Power & Light Co.*, 40 PUR4th 405, 424 (Wash., 1980).

[52]*Re Rate Design for Electric Corporations*, *op. cit.*, p. 286.

[53]See, *e.g.*, *Re Indiana Bell Teleph. Co., Inc.*, 82 PUR4th 402 (Ind., 1987). Such service, however, is not popular. See "Phone Companies Draw Fire by Seeking To Base Local Phone Charges on Usage," *The Wall Street Journal*, January 6, 1987, p. 31.

[54]See, *e.g.*, *Re Moore Universal Telephone Service Act*, Decision No. 84-04-053 (Cal., 1984), as amended, Decision No. 86-02-021 (Cal., 1986); *Re Telephone Lifeline Rates*, *op. cit.*; *Re Nevada Bell*, 81 PUR4th 110 (Nev., 1987). See also *Re Specialized Telephone Equipment Provided to Disabled Subscribers*, 83 PUR4th 427 (Cal., 1987).

[55]See "Half of the States Now Offer Lifeline Aid Under One of FCC's Three Plans," 5 *State Telephone Regulation Report* 1 (October 8, 1987). See also U.S. General Accounting Office, *Telephone Communications: Cost and Funding Information on Lifeline Telephone Service* (Gaithersburg, Md., 1987).

[56]For electricity, the commission established (for single-family dwellings), 250 kilowatt-hours per month for lighting, cooking, and refrigeration; 250 kilowatt-hours per month for water heating; and from 550 to 1,420 kilowatt-hours per month, depending upon four climatic zones, for space heating. For natural gas, the commission established six therms per month for cooking; twenty therms per month for water heating; and from fifty-five to 140 therms per month, depending upon the four climatic zones, for space heating. California Pub. Utilities Comm., Decision No. 86087 (1976). On the California experience, see Albin J. Dahl, "California's Lifeline Policy," 102 *Public Utilities Fortnightly* 13 (August 13, 1978); William Symons, Jr., "California Rate Experiments: Lifeline or Lead-weight?," 102 *Public Utilities Fortnightly* 11 (October 26, 1978).

[57]*Re Duke Power Co.*, 26 PUR4th 241 (N.C., 1978).

[58]*Re Narragansett Elec. Co.*, 23 PUR4th 576 (R.I., 1978). Yet, the Maine commission rejected a similar proposal for an elderly, low-income residential rate schedule (a 20 percent credit against base monthly electric rates for the first 500 kilowatt-hours of consumption), on the grounds that the commission should not make "social judgments of the nature suggested by this rate" and that there was no evidence on the record "to support any contention that customers who would qualify for the elderly low-income rate are in need of rate relief any more than other low-income customers." *Re Central Maine Power Co.*, 26 PUR4th 388 (Me., 1978).

[59]*Re Montana Power Co.*, Order No. 4521b (Phase II) (Mont., 1979).

[60]See Jean H. Standish et al., *Trends Report of Energy Assistance Programs in the Fifty States, 1979-1984* (Columbus, Ohio: National Regulatory Research Institute, 1985).

[61]Pub. Law 96-126 (1979). Under the original program, $400 million was distributed directly to individuals receiving supplemental security income; $800 million

was given to the states in block grants, with each state's plan for distributing its block grant subject to the approval of the Department of Health, Education, and Welfare. See "Energy Assistance Checks Sent to Low-income Individuals," 105 *Public Utilities Fortnightly* 42 (January 17, 1980).

[62]In addition to the references cited in the following pages, the studies and reports of the Electric Power Research Institute (Palo Alto, California) provide a wealth of information on electric utility rate design.

[63]There were many other interesting variations in existence, including a New England utility with an ingenious block rate structure which used the number of cows on a farm as a substitute for a demand meter; a western utility with a schedule for "bachelor residential service"; and another which furnished "free service to widows, a majority of whom are not metered." See Louis Zanoff, "How New Are the 'New' Rate-making Principles?," 105 *Public Utilities Fortnightly* 6, 8 (January 17, 1980).

[64]C. Woody Thompson and Wendell R. Smith, *Public Utility Economics* (New York: McGraw-Hill Book Co., Inc., 1941), p. 394.

[65]*Ibid.*

[66]The widespread use of interconnections with other electric utilities reduces the necessary reserve capacity. Under these arrangements, utility A can buy power from utility B during peak or emergency situations. See Chapter 13.

[67]Eli W. Clemens, *Economics and Public Utilities* (New York: Appleton-Century-Crofts, Inc., 1950), p. 284.

[68]"The power factor is the ratio of the power to the volt-amperes. For direct current, volts multiplied by amperes equals watts. For alternating current, which is most widely used, volt-amperes are the equivalent of watts for lighting uses but not where the energy is transformed into mechanical power. Here at a given wattage a power user may require alternating generators, conductors and transformers of nearly a third greater capacity than the kilowatts he employs and for which he is supposed to pay. The power factor is the coefficient which expresses the significance of this element in the situation. The relation between the kilowatt-hours consumed and the necessary generating capacity and other equipment is in inverse ratio to the power factor of the consumer's apparatus." Emerson P. Schmidt, *Public Utility Economics* (St. Louis: John S. Swift Co., Inc., 1940), p. 134.

[69]Emery Troxel, *Economics of Public Utilities* (New York: Holt, Rinehart & Winston, Inc., 1947), p. 609.

[70]Wilcox, *op. cit.*, p. 331. See also Ralph K. Davidson, *Price Discrimination in Selling Gas and Electricity* (Baltimore: The Johns Hopkins Press, 1955).

[71]Bonbright, *op. cit.*, p. 350.

[72]Russell E. Caywood, *Electric Utility Rate Economics* (New York: McGraw-Hill Book Co., Inc., 1956), pp. 156-69. Bonbright notes that there are at least twenty-nine such formulas in existence. "Most of them have no claim whatever to validity from the standpoint of cost determination, and only a dubious claim to acceptance as compromise measures of reasonable rates." Bonbright, *op. cit.*, p. 351.

[73]Bonbright, *op. cit.*, p. 353.

[74]Wilcox, *op. cit.*, p. 333.

[75]"It is obvious that this method is not entirely satisfactory because a class load at the time of the system peak might be zero, while at some other time it might be of considerable size; yet no expense would be allocated to it." Caywood, *Electric Utility Rate Economics*, *op. cit.*, p. 156.

[76]Bonbright, *op. cit.*, p. 350-68.

[77]Irwin M. Stelzer, "Rate Structure Reform — A Federal or State Problem?" (New York: National Economic Research Associates, Inc., 1977).

[78]These two illustrative rate schedules are for the Virginia Electric and Power Company, as adopted by the Virginia commission in rate cases decided in 1970 and 1985, respectively.

[79]*Re Madison Gas & Elec. Co., op. cit.*, p. 46.

[80]*Ibid.*, concurring statement by Commissioner Richard D. Cudahy, pp. 52-53.

[81]*Ibid.*, commission decision, p. 36.

[82]Weiss, *op. cit.*, p. 287. See also William G. Shepherd, "Price Structures in Electricity," in Albert L. Danielsen and David R. Kamerschen (eds.), *Current issues in Public-Utility Economics: Essays in Honor of James C. Bonbright* (Lexington, Mass.: D. C. Heath & Co., 1983), chap. 9.

[83]See, *e.g.*, Paul L. Joskow, "Public Utility Regulatory Policies Act of 1978: Electric Utility Rate Reform," 19 *Natural Resources Journal* 787 (1979).

[84]The state commissions also were required to consider and adopt, if appropriate, lifeline rates.

[85]The regulatory standards, contained in Section 113, are (*1*) Master metering — master metering of new buildings shall be prohibited or restricted to the extent necessary to meet the objectives of the rate reform provisions. (*2*) Automatic adjustment clauses — no utility may increase any rate under an automatic adjustment clause unless the clause is reviewed (a) at least once every four years to ensure that it provides incentives for efficient use of resources and (b) at least once every two years to ensure maximum economies in operations and purchases that impact utility rates. (*3*) Information to consumers — a utility shall provide the following types of rate information to consumers: (a) an explanation of the existing rate schedule, (b) an explanation of any new rate schedule applied for or proposed, (c) at least once a year, a summary of existing rate schedules for each class of customer having a separate rate, and (d) on request, a statement of consumption for each billing period for the prior year. (*4*) Advertising — a utility may not recover from ratepayers the costs of promotional or political advertising. (*5*) Termination of service — service shall not be terminated except pursuant to certain enumerated procedures; specifically, reasonable prior notice, including notice of rights and remedies, and reasonable provisions for (a) elderly and handicapped consumers and (b) consumers who have established inability to pay, where termination would be especially dangerous to health. Standards (*4*) and (*5*) apply to both electric and gas utilities. The state commissions were to consider and to adopt these standards, if appropriate, by November 1980. See Economic Regulatory Administration, U.S. Department of Energy, *Annual Report to Congress, May 1980* (Washington, D.C.: U.S. Government Printing Office, 1980), Vols. 1 and 2. For representative state commissions decisions regarding the five standards, see (*1*) *Re Investigation of Master Metering*, 37 PUR4th 110 (S.D., 1980); *Re Master Metering Standards*, 37 PUR4th 119 (Idaho, 1980); (*2*) *Re Energy Cost Adjustment Clauses*, 41 PUR4th 81 (Cal., 1980); *Re Uniform Fuel Adjustment Clauses*, 45 PUR4th 1 (Ill., 1981); (*3*) *Re Public Utility Regulatory Policies Act Standards*, 46 PUR4th 39 (Alaska, 1982); *Re Public Utility Regulatory Policies Act*, Case Nos. U-6490, U-8455 (Mich., 1986); (*4*) *Re Potomac Elec. Power Co.*, 36 PUR4th 139 (D.C., 1980); *Re Rule Making Relating to Advertising Expenditures*, 39 PUR4th 295 (N.C., 1980); (*5*) *Re Termination of Services Standard*, 83 PUR4th 444 (Mich., 1987).

[86]See *Annual Report to Congress, May 1980, op. cit.;* two reports by the National Association of Regulatory Utility Commissioners, "State Commission Progress Under

the Public Utility Regulatory Policies Act of 1978" (Washington, D.C., 1980) and "Second Report on State Commission Progress Under the Public Utility Regulatory Policies Act of 1978" (Washington, D.C., 1982). For an overview, see *1985 Annual Report on Utility and Carrier Regulation* (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1987), pp. 681-93. For representative state commission decisions regarding the six ratemaking standards, see (*1*) *Re Potomac Elec. Power Co.*, 36 PUR4th 139 (D.C., 1980); *Re Cost-of-Service Ratemaking Standards*, 44 PUR4th 33 (Tex., 1981); (*2*) *Re Carolina Power & Light Co.*, 49 PUR4th 188 (N.C., 1982); *Re Potomac Elec. Power Co.*, 62 PUR4th 1 (D.C., 1984); (*3*) *Re Commonwealth Edison Co.*, 35 PUR4th 49 (Ill., 1980); *Re Virginia Elec. & Power Co.*, 64 PUR4th 636 (W.Va., 1984); (*4*) *Re Commonwealth Edison Co., op. cit.*, *Re Time-of-day and Seasonal Electric Rates*, 42 PUR4th 494 (Iowa, 1981); (*5*) *Re Dept. of Pub. Service*, 37 PUR4th 497 (Minn., 1980); *Re Virginia Elec. & Power Co., op. cit.*; (*6*) *Re Interruptible Rate and Load Management Standards*, 43 PUR4th 163 (Iowa, 1981); *Re Electric Utility Conservation and Load Management*, 55 PUR4th 351 (Pa., 1983).

[87]See John A. Casazza, "Understanding the Transmission Access and Wheeling Problem," 116 *Public Utilities Fortnightly* 35 (October 31, 1985). The FERC has limited authority to mandate wheeling [see *e.g., Southeastern Power Administration v. Kentucky Utilities Co.*, 25 FERC Par. 61,204 (1983)], but it has preempted jurisdiction over all interstate wheeling rates [*Re Florida Power & Light Co.*, 29 FERC Par. 61,140 (1984), and 40 FERC Par. 61,045, 85 PUR4th 1 (1987)]. On state activity, see *Re Electric Transmission Service*, 82 PUR4th 473 (Conn., 1987). The NRC may impose limited wheeling obligations as part of nuclear plant license conditions under the antitrust provisions of the Atomic Energy Act of 1954. [See Federal Energy Regulatory Commission, *Power Pooling in the United States* (Washington, D.C.: U.S. Government Printing Office, 1981), p. 58.] On antitrust issues, see *Otter Tail Power Co. v. United States*, 410 U.S. 366, 97 PUR3d 209 (1973) (holding that transmission lines are "essential facilities" under the antitrust laws when they cannot be economically duplicated); *City of Chanute et al. v. Kansas Gas & Elec. Co.*, 564 F. Supp. 1416, 54 PUR4th 162 (D. Kan. 1983).

[88]Economy energy refers to large-scale power transfers, where it is less expensive to purchase than to produce electricity. In 1982 and 1983, for example, both the Power Authority of the State of New York and the New England Power Pool signed long-term contracts with Hydro-Quebec to import up to 111 billion kilowatt-hours and 33 billion kilowatt-hours of electricity, respectively. The New England Power Pool estimated that the contract would save its members $1 billion over its life when compared with the cost of power from oil-fired generating stations. *The Wall Street Journal*, March 18, 1983, p. 10.

[89]See, *e.g.*, David W. Penn, "A Municipal Perspective on Electric Transmission Access Questions," 117 *Public Utilities Fortnightly* 15 (February 6, 1986). But see, *e.g.*, Jerry L. Pfeffer, "Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited," 116 *Public Utilities Fortnightly* 26 (October 31, 1985); Michael B. Rosenzweig and Joshua Bar-Lev, "Transmission Access and Pricing: Some Other Approaches," 118 *Public Utilities Fortnightly* 20 (August 21, 1986).

[90]"This may be either to cover the full costs imposed by wheeling or to gather a large share of the profits available because of the cost differential between buyer and seller." Kevin Kelly et al., *Some Economic Principles for Pricing Wheeling Power* (Columbus, Ohio: National Regulatory Research Institute, (1987), p. 2. See also Kevin Kelly

(ed.), *Non-Technical Impediments to Power Transfers* (Columbus, Ohio: National Regulatory Research Institute, 1987).

[91]Pfeffer, *op. cit.*, p. 29. See Oak Ridge National Laboratory, "Analysis of Power Wheeling Services" (A report prepared for the Federal Energy Regulatory Commission, 1984); Pfeffer, Lindsay and Associates, Inc., "A Review of Current Practice and Emerging Issues in the Design of Rates for Transmission Service" (A report prepared for the Edison Electric Institute, 1985); Kelly et al., *op. cit.*, esp. Appendix F.

[92]*American Elec. Power Service Corp., et al. v. Federal Energy Regulatory Comm.*, 675 F. 2d 1226, 45 PUR4th 364, 366 (D.C. Cir. 1982). "Cogeneration usually refers to the use of heat that would otherwise be wasted after electricity is generated ('topping cycle'); the term also applies to systems that generate electricity from heat left over from an industrial process ('bottoming cycle'). Because both heat and electricity are created in a single process, about half as much fuel is used to produce electricity and heat as would be needed to produce the two separately. While cogeneration is not a new concept, its popularity had declined steadily since the turn of the century as energy from central station power plants became relatively inexpensive. With the rise in utility rates in recent years, however, it became apparent that cogeneration might again become economical on a broad scale." *Ibid.* See also U.S. General Accounting Office, *Industrial Cogeneration — What It Is, How It Works, Its Potential* (Gaithersburg, Md., 1980).

[93]"Combined estimates of installed capacity and firm project commitments by independent producers are in the 20,000-megawatt range, while less certain undertakings could substantially increase that total. The amount of independently generated electricity has more than doubled since 1978, and should repeat that performance in the next ten or fifteen years." "PURPA: Still Hazy After All These Years," 118 *Public Utilities Fortnightly* 33 (July 10, 1986). See, *e.g.*, Howard J. Brown (ed.), *Decentralizing Electricity Production* (New Haven: Yale University Press, 1983).

[94]Order No. 69, 45 *Fed. Reg.* 12214 (FERC, 1980). The FERC's Rules were upheld in *American Elec. Power Service Corp., et al. v. Federal Energy Regulatory Comm., op. cit., rev'd sub nom. American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 52 PUR4th 329 (1983).

The act also provides for the provision of backup service from utilities at just and reasonable rates [see, *e.g., Re Standby Rates for Electric Utilities*, 81 PUR4th 1 (Fla., 1987)] and for interconnections with utilities under terms and conditions consistent with reliable system operation [see, *e.g., Re Transmission System Operations for Cogeneration and Small Power Production Development*, 64 PUR4th 537 (Cal., 1985)]. The FERC may exempt qualifying facilities from certain state and federal regulations [see, *e.g., Federal Energy Regulatory Comm. v. State of Mississippi*, 456 U.S. 742, 47 PUR4th 1 (1982)]. See also Robert D. Stewart, Jr., "The Law of Cogeneration in Oklahoma," 118 *Public Utilities Fortnightly* 22 (November 27, 1986).

[95]See, *e.g.*, "Calculating Capacity Costs in Cogeneration Rates," 108 *Public Utilities Fortnightly* 57 (September 24, 1981); *The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs* (Columbus, Ohio: National Regulatory Research Institute, 1982); *Re Electric Avoided Cost Rates*, 73 PUR4th 138 (Mont., 1986) (discussing nine methods for calculating avoided costs); "Recent Decisions on Avoided Cost Methodologies and Standard Offer Cogeneration Contracts," 118 *Public Utilities Fortnightly* 46 (September 18, 1986); "Cogeneration and Small Power Production: Recent Regulatory Developments," 119 *Public Utilities Fortnightly* 46 (June 25, 1987); Hethie S. Parmesano, "Avoided Cost Payments to Qualifying Facilities: Debate Goes On," 120 *Public Utilities Fortnightly* 34 (September 17, 1987). See also Steven R. Miles,

"Full-Avoided Cost Pricing Under the Public Utility Regulatory Policies Act: 'Just and Reasonable' to Electric Consumers?," 69 *Cornell Law Review* 1267 (1984). On related issues, see "PURPA Still Hazy After All These Years," *op. cit.*

For representative state decisions, see *Re Cogenerators and Small Power Producers*, 51 PUR4th 369 (Ark., 1983); *Re Cogeneration and Small Power Production*, 51 PUR4th 399 (Wyo., 1983); *Re Rates for Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities*, 64 PUR4th 369 (N.C., 1985); *Re Cogeneration and Small Power Production*, 83 PUR4th 19 (Utah, 1987).

[96]*Greensboro Lumber Co. v. Georgia Power Co.*, 643 F. Supp. 1245 (N.D. Ga. 1986).

[97]*Resolution*, E-3017 (Cal., 1987).

[98]Kenneth W. Costello, O. Douglas Fulp, and Calvin S. Monson, "Incentive and Economic Development Rates as a Marketing Strategy for Electric Utilities," 117 *Public Utilities Fortnightly* 27, 28 (May 15, 1986). See also Louis R. Jahn and Mark S. Berndt, "A Cost-of-Service Basis for Utility Marketing Programs," 116 *Public Utilities Fortnightly* 42 (September 19, 1985).

[99]*Re Narragansett Elec. Co.*, 57 PUR4th 120, 131 (R.I., 1983).

[100]*Re Detroit Edison Co.*, 57 PUR4th 540, 541 (Mich., 1984).

[101]*Re Pub. Service Co. of N.H.*, 57 PUR4th 563, 587 (N.H., 1984). See also *Re Hoosier Energy Rural Elec. Cooperative, Inc.*, 78 PUR4th 120 (Ind., 1986).