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PUBLIC UTILITY REGULATORY POLICY ACT OF 1978: ELECTRIC UTILITY RATE REFORM

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The Public Utility Regulatory Policies Act of 1978[1] (PURPA) represents an effort by the federal government to affect the ways in which state public utility commissions regulate the retail sales of electric and gas utility companies. The act also amends portions of the Federal Power Act[2] to expand the authority of the Federal Energy Regulatory Commission (FERC) in certain areas of electricity supply and reliability, such as interconnection, wheeling and cogeneration, and its regulatory authorities with respect to wholesale electricity rates. Finally, the act includes provisions for the establishment of small hydroelectric projects, resolution of problems associated with the expansion of crude oil transportation systems, grants for a utility regulatory institute and coal research laboratories, and the voluntary and emergency conversion of natural gas users to other fuels.

This paper focuses on the economic foundations and implications of the provisions of Title I of PURPA, which deals with retail sales by electric utilities. Much of this discussion also has some relevance to Title III of the act which deals (much less extensively) with retail sales by natural gas utilities.

TITLE I: RETAIL REGULATORY POLICIES FOR ELECTRIC UTILITIES

Title I of PURPA[3] establishes a variety of requirements and procedures for state public utility commissions to follow in establishing retail electricity rates. Prior to the enactment of PURPA these activities had been entirely within the jurisdiction of state commissions. While PURPA does not change the primary jurisdiction of state regulatory commissions or supersede state law with regard to the determination of electricity rates, it does obligate state commissions to consider a large number of specific rate-making standards.[4] The act also gives consumer groups, electric utilities, and the Department

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1. 16 U.S.C.A. § § 2601-2645 (Supp. 1979).
2. 16 U.S.C. § § 791a-825r (1976).
3. 16 U.S.C.A. § § 2611-2613 (Supp. 1979).
4. 16 U.S.C.A. § § 2621-2627 (Supp. 1979).

of Energy (DOE) the right to intervene in state regulatory hearings and certain appeals rights in the state and federal courts.[5]

The primary purpose of Title I is to encourage state commissions to consider and implement new ratemaking methods and rate structures that will promote the objectives of the act. These objectives are stated as (1) increased conservation of electric energy, (2) increased efficiency in the use of facilities and resources by electric utilities and (3) equitable retail rates for electric consumers.[6] The act provides relatively detailed guidance concerning the kinds of rates that should be considered. But by and large it obligates the state commissions only to "consider" and make "determinations," while leaving ultimate implementation decisions up to the state commissions themselves.[7]

Section 111[8] of the act requires state commissions to consider and determine the applicability of six specific retail ratemaking standards. The process of consideration and determination must be conducted in public evidentiary hearings and while generic hearings are permitted, considerations of the standards and determination of applicability must be done separately for each utility. The following six ratemaking standards are established by the act under Section 111.

(1) Cost of Service: Rates charged to each class of electric customers shall be designed to reflect the costs of providing electric service to that class. Statutory guidance regarding the meaning of "cost of service" is provided in Section 115(a) of the act, which I discuss below.

(2) Declining Block Rates: The energy component of an electric rate for any class of customers cannot decrease with aggregate electricity consumption unless the utility can demonstrate the costs of providing the energy also decrease with aggregate consumption.

(3) Time-of-Day Rates: The rates charged for any class of customers shall vary on a time-of-day basis reflecting the variation in the costs of providing the service on a time-of-day basis. Such time-of-day rates should not be applied if they are not deemed cost effective. The meaning of "cost effective" is elaborated in Section 115(b), which I discuss below.

(4) Seasonal Rates: The rates charged for each class of customers shall be on a seasonal basis, and reflect the seasonal variation in the

5. 16 U.S.C.A. § §2631, 2633 (Supp. 1979).
6. 16 U.S.C.A. §2611 (Supp. 1979).
7. 16 U.S.C.A. §2627 (Supp. 1979).
8. 16 U.S.C.A. §2621 (Supp. 1979).

costs of providing electric service, to the extent that such cost variation exists for a particular utility.

(5) Interruptible Rates: Industrial and commercial consumers shall be offered an interruptible rate which reflects the cost of providing interruptible service to the particular class of which the consumer is a member.

(6) Load Management Techniques: Each electric utility shall offer to its customers such load management techniques as are deemed (a) to be practicable and cost effective as determined under Section 115(c); (b) to be reliable; and (c) to provide useful energy or capacity management advantages to the electric utility.

The act gives each state two years to begin the consideration of these standards or to set a hearing date, and three years to complete the "consideration" and "determinations" regarding these federal standards.[9] If the state commissions decide not to implement the federal ratemaking standards, they are to specify clearly why they have chosen not to do so. Apparently the act assumes states will implement these ratemaking standards if they are consistent with the purposes of PURPA and state law. However, it does not appear that state commissions *must* implement the standards even if these two criteria are met. Presumably, in this case state commissions would have to specify good reasons for not implementing the standards or face the possibility of successful appeals through the state courts by the Department of Energy or intervenors, or further federal initiatives. However, the conference report implies that state commissions have very broad authority regarding decisions to adopt the standards or not.[10]

Section 113[11] of PURPA specifies "certain standards" in addition to the six ratemaking standards in Section 111 which state commissions are to consider and adopt within two years, if these standards are consistent with the purposes of the act and state law. The state commissions apparently have less discretion when deciding whether to adopt these "certain standards" than the six ratemaking standards. The five "certain standards" are:

(1) Master Metering: Master metering of electric service in new buildings shall be prohibited or restricted to the extent necessary to carry out the purposes of the act. Section 115(d) indicates this standard should be applied to multiunit buildings where the individual units can control their individual consumption of electricity, and

9. 16 U.S.C.A. §2622 (Supp. 1979).
10. S. REP. NO. 1292, 95th Cong., 2nd Sess. 70-75 (1978).
11. 16 U.S.C.A. §2623 (Supp. 1979).

where the long-run benefits *to the consumer* of replacing the master meter with individual meters are greater than the additional costs of the individual meters.

(2) Automatic Adjustment Clauses: No electric utility may increase any rate according to a fuel adjustment clause unless the following requirements specified in Section 115(e) are satisfied. Each clause must be determined at least every four years, in an evidentiary hearing by the state regulatory authority. The hearings are to determine if the clause provides incentives for efficient use of resources by the electric utility. The clause must be reviewed at least every two years, to insure the maximum economies in those operations and purposes which affect the rates to which the adjustment clause applies.

(3) Information to Consumers: Each electric utility must provide information on rate schedules that are available and applicable to each consumer. Details about the information to be provided are specified in Section 115(f).

(4) Procedures for Termination of Electric Service: Electric service may not be terminated unless the following conditions are met as specified in Section 115(g). Reasonable prior notice must be given before termination as well as a reasonable opportunity to dispute the reasons for termination. If termination of service would be especially dangerous to health, service may not be terminated if the customer is unable to pay for the service or is able to pay for such service only in installments. It appears that state commissions *must* implement this provision if it is consistent with state law.

(5) Advertising: No electric utility may recover the cost of promotional and political advertising except from its shareholders. Section 115(h) exempts certain types of advertising that promotes the purposes of the act, or that concerns employment opportunities, service interruptions or emergencies.

Section 115 of the act elaborates on the rules to be used in considering the two different groups of standards. Those portions related to the five "certain standards" already have been mentioned. The remaining portions of Section 115 deal with the federal ratemaking standards established under Section 111.

(a) Cost of Service: The cost of service methodology employed under Section 111, to the maximum extent practicable, should (1) permit identification of differences in cost for each class of customer attributable to daily and seasonal time of use of service; (2) permit identification of differences in cost attributable to differences in customer demand and energy (fuel plus other variable costs). The methodology should consider how total costs would vary with additional power added to meet peak demand relative to base demand, and with additional kilowatt-hours of electric energy delivered to consumers.

(b) Time-of-Day Rates: A time-of-day rate should be considered cost effective if the long-run benefits of such a rate to the utility and customers in the class are likely to exceed the metering and other costs associated with such rates.

(c) Load Management Techniques: Load management techniques are cost effective if they are likely to reduce maximum kilowatt demand on the utility, and the long-run cost savings to the utility are likely to exceed the long-run costs of each technique.

Section 114[12] of the act deals with "lifeline rates." These provide special discount prices to consumers using small amounts of electricity. The presumption is that minimal levels of electricity consumption are required to meet "essential needs" and by providing lower rates for small amounts of consumption, low-income people can afford at least the "essential" amounts of power. Section 114 provides that no provision of the act should be interpreted as forbidding a regulatory commission from offering lifeline rates even if such rates do not cover costs. In addition, this section provides that for any utility which does not have a lower rate for "essential needs," the state commission must hold an evidentiary hearing within two years to determine whether such a rate should be offered.

ECONOMIC AND REGULATORY ISSUES LEADING TO PURPA TITLE I

The passage of PURPA followed several years of increasing pressure to institute electric power rate reforms, especially the application of economic principles to the process of electricity ratemaking. This increased interest in reform has been caused by a number of factors which I have discussed in more detail elsewhere,[13] and which only are summarized here. First, beginning in the late 1960s, the costs of electricity began to increase after several years of moderate decline. This trend accelerated in the early 1970s, especially after the rapid increases in oil prices beginning in late 1973. The increases in the nominal costs of electric power production can be attributed to several factors. First, the historical decrease in average boiler efficiencies leveled off as modern boiler technology replaced older, less

12. 16 U.S.C.A. § 2624 (Supp. 1979).

13. *See generally* Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation,* 17 J. LAW AND ECON. 291 (1974); Joskow, *Electric Utility Rate Structures in the United States: Some Recent Developments* in PUBLIC UTILITY RATE MAKING IN AN ENERGY CONSCIOUS ENVIRONMENT (W. Sichel ed. 1978).

efficient systems.[14] Second, as utility systems became larger and interconnection and coordination spread, the advantages attributable to economies of scale were gradually exhausted.[15] Third, rising fuel prices and interest rates, in the absence of countervailing increases in production efficiency and scale economies, led to higher nominal unit electricity costs. Finally, the marginal costs of new plant and equipment rose at a rate significantly greater than the overall rate of inflation. This increase was caused by the general increase in construction costs, environmental costs, and siting restrictions that affect electric power generation and transmission facilities.

Increasing nominal production costs in the presence of fixed electricity prices established by state regulatory commissions inevitably led to a decline in the profitability of electric power companies.[16] This in turn led these companies to make an unprecedented number of requests before formal state regulatory bodies for higher prices and rates of return in the face of increasing costs of capital. In 1965 there were only two formal reviews of rate increase requests by class A and B electric utilities completed in the United States, but by 1974 this number had increased to 78.[17]

Increases in costs of electric power production and the rapid increase in formal regulatory activity were accompanied by an expanding and aggressive environmental movement, which had chosen the electric power industry as one of its main targets. Environmentalists were interested in reducing the rate of growth in electricity consumption since they anticipated this would reduce the need for more generating facilities and cut the impact of electric power expansion on the environment. Several environmental groups, particularly the Environmental Defense Fund, saw rate reform and especially the use of marginal cost pricing principles and peak-load pricing, as an important instrument for achieving these objectives.[18] And as prices began to increase rapidly (especially after 1974), consumer groups started advocating electric power rate reforms which would consider the income distribution implications of rising electricity rates. While

14. *See generally* Joskow & Mishkin, *Electric Utility Fuel Choice Behavior in the United States*, 18 INT'L ECON. REV. 719 (1977).

15. The production of some commodity by a firm is characterized by economies of scale when the average cost of production declines as output increases. The definition takes all input prices and the state of technology as fixed.

16. *Supra* note 13.

17. *Supra* note 13.

18. The Environmental Defense Fund was an active participant in the Madison Gas & Electric case (WISCONSIN PUBLIC SERVICE COMPANY COMMISSION RE MADISON GAS & ELECTRIC COMPANY, order dated August 8, 1978), participated in the generic hearings held by the New York State Public Service Commission and has been active before the California Public Utilities Commission. *See* ELECTRICAL WEEK, Nov. 29, 1976, at 3.

environmental groups advocated the use of marginal cost pricing principles to discourage the growth of peak electricity demand, consumer groups advocated "lifeline rates" which would reduce the prices charged for retail customers consuming relatively small amounts of electricity. These consumer groups assumed income and electricity consumption were highly correlated and that overall increases in rates were especially hard on those with less money.[19] Increased funding for these environmental and consumer groups combined with relaxed standing requirements of public utility commissions, to allow these groups to intervene in the increasing number of formal state regulatory proceedings. The groups argued the state commissions should pay more attention to issues of rate design and not just focus on issues of average rate level and profitability.

In bolstering their case for rate reform, environmental groups found the substantial body of economic literature on marginal cost pricing of electric power led to rate reform conclusions consistent with their objectives. Over the preceding two decades a substantial economic literature on peak load pricing, based on marginal cost pricing principles, had evolved in the United States, England and France. Work by Turvey[20] and by economists at Electricité de France[21] developed and applied this theoretical work to the particular conceptual and empirical problems of determining marginal costs and establishing associated rate structure for the electric power industry. This work became an integral part of the presentations of those arguing for electricity rate reform.

While the theoretical and empirical details of peak load pricing based on marginal cost pricing principles still are evolving, the basic qualitative implications have remained pretty much the same. The opportunity cost of electricity consumption tends to vary from hour to hour during the year, depending on the relationship between system demand and supply. Marginal costs are relatively high during "peak" periods when capacity is close to full use and relatively low during "off-peak" periods when demand is far below available capacity. Marginal opportunity costs are relatively high during the daytime hours in either the summer or the winter (depending on the mix of heating and air-conditioning loads) and relatively low at night, on weekends and in the spring and fall. Ignoring transactions costs (asso-

19. The objectives of those advocating rate reform for redistributive purposes and those advocating rate reform on efficiency grounds are clearly different, although many commissions have tended to get them confused or to link them together so as to satisfy both sets of interest groups.

20. *See generally* R. TURVEY, OPTIMAL PRICING AND INVESTMENT IN ELECTRICITY SUPPLY (1968).

21. *See generally* J. NELSON, MARGINAL COST PRICING IN PRACTICE (1964).

ciated primarily with the costs of metering), efficient pricing based on marginal cost principles implies that prices should vary by time of day and season of the year. However, in the United States, such time-of-day rates had not been introduced except for scattered controlled water heating rates for residential customers.[22] Larger commercial and industrial customers often faced rate structures which imposed a "demand charge" based on the customer's individual peak demand, but these rates were not geared to the relevant *system* demand and supply characteristics, and the charges did not vary by time of day. As a result, in the early 1970s electric power rates in the United States encouraged too much consumption during peak periods and not enough consumption during off-peak periods. Peak demands were excessive, the system load factor of utilities was too low, and the *average* cost of electricity was too high.

The proposals for peak load pricing systems based on marginal cost principles were attractive to some public utility commissions for other reasons. Faced with a growing number of requests for large rate increases, the commissions found themselves the focus of considerable controversy. On the one hand utility companies argued the increases were required to finance increasingly expensive expansions in production capacity. On the other hand, the commissions were faced with angry consumer groups opposed to the rapid increases in prices and environmental groups opposed to the expansion in capacity. As state executives began to appoint commissioners who represented consumer and environmental viewpoints, more and more commissions began to examine rate structure issues carefully.

In a number of cases the commissions also ordered time-of-day rates be made available to some classes of customers, usually large industrial and commercial users. Lifeline rates also were introduced in a number of states. The Madison Gas and Electric case begun in 1972 and decided in 1974 by the Wisconsin Public Service Commission was a landmark.[23] The majority of the commissioners embraced the economic principles of marginal cost pricing and indicated a longer run interest in seasonal and time-of-day rates. By 1977, 12 state commissions had held generic hearings on retail electric rate structure reform and 19 states had time-of-day rates available or proposed for at least some customers. New York and Wisconsin had made substantial progress in implementing rate reform by this time. In December 1974 the National Association of Regulatory Utility

22. The situation has been far different in Europe, however. *See* NERA, ANALYSIS OF ELECTRICITY PRICING IN FRANCE AND GREAT BRITAIN, ELECTRIC UTILITY RATE DESIGN STUDY TOPIC 1.2 (1977); B. MITCHELL & W. MANNING, PEAK-LOAD PRICING: EUROPEAN LESSONS FOR U.S. ENERGY POLICY (1978).

23. *Supra* note 18.

Commissioners (NARUC) asked the Electric Power Research Institute (EPRI) to conduct several types of studies into rate design issues as an aid to the state commissions. Since then EPRI's Rate Design Study has produced about 60 reports dealing with many aspects of the rate design problem, including analyses of alternative costing and pricing methodologies, demand elasticity considerations, rate experiments, and metering and other technologies for exploiting seasonal and time-of-day prices. NARUC's request reflected the growing interest of state commissions in these issues and the need for information about alternatives proposed in hearings.

The move to new rate structures based on marginal cost principles faced considerable opposition. As a general matter large commercial and industrial consumers were opposed to the rate reform initiatives because they felt that they would end up paying more for electricity. This perception was not motivated entirely by the fact that some of these customers used power more intensively at peak times than their rates reflected, and/or would have difficulty reducing peak consumption in response to higher prices (although this was one source of the objections from large users). Perhaps more important was the fear that one way or another they would end up paying for a larger proportion of the total costs of supplying electricity.

This perception was based on a number of reasonable assumptions. If all customers were charged marginal cost, total revenues generated would be larger than the total revenues allowed, using traditional average historical cost calculations for determining "total revenue requirements." Due to (1) inflated construction costs; (2) the use of the average historical cost of debt for making allowed rate of return determinations; and (3) prevailing regulatory depreciation and valuation procedures, marginal costs appeared to be above average historical cost as it is calculated for determining the total revenues allowed to the utility. Under pressure from consumer groups lobbying for lifeline rates and other forms of rate relief, the larger customers feared they would pay marginal cost, while smaller residential customers paid less than average historical cost. As a result larger users thought they would bear a larger proportion of the revenue requirements than they had under the prevailing system. Industrial customers argued higher rates would make them less competitive with firms in other states, and predicted dire economic consequences resulting from reform.

Many utilities also opposed the rate reform initiatives. Faced with deteriorating financial situations[24] they were concerned about the

24. Joskow & MacAvoy, *Regulation and the Financial Condition of the Electric Power Companies in the 1970's*, 65 AM. ECON. REV. 295, 295-301 (May 1975).

uncertainties associated with these new rates. They did not know how consumption would respond to seasonal time-of-day rates and worried about the additional metering costs. They viewed time-of-day rates as yielding more unstable streams of revenues, since so much revenue would be produced by a relatively small number of hours during the year. In addition, they were concerned the commissions were promising consumers much more than could actually be delivered, especially since most commissions glossed over the fact that while some customer bills might fall with time-of-day rates and lifeline rates, other easily could increase with the new rates. They feared the wrath of a lot of unhappy customers. Finally, I suspect that many of those within utility companies who traditionally had been responsible for ratemaking preferred to keep doing things the way they always had.

The large consumers and the utilities raised a large number of objections to time-of-day pricing in general and marginal cost pricing in particular. While many commissions moved steadily but cautiously toward the introduction of these types of rate reforms, many other states virtually did nothing.

Until passage of PURPA, these issues were argued and resolved on a state-by-state basis. After all, it was the states that had exclusive regulatory authority over retail rates. The Federal Power Act limited the rate activities of the Federal Power Commission (now FERC) to interstate wholesale rate activities,[25] and the FPC essentially ignored the growing controversy within the states over rate structure reform. After the oil embargo and the rapid rise in energy prices in 1974, federal authorities responsible for energy policy in the executive branch (the Federal Energy Office, Federal Energy Administration, and now the Department of Energy) took an increasing interest in state rate reform activities. These state initiatives were seen as ways of encouraging energy conservation, reducing the demand for electricity, improving load factors and making base load coal and nuclear plants more attractive.[26] However by and large the executive branch efforts were limited to encouragement and to funding about ten residential time-of-day experiments. These were designed to resolve some of the controversies about the costs and effects of time-of-day rates on residential consumers.[27]

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25. 16 U.S.C. §824 (1976).

26. *See* WISCONSIN PUBLIC SERVICE COMMISSION RE MADISON GAS AND ELECTRIC COMPANY (order dated August 8, 1978). *See generally* EXECUTIVE OFFICE OF THE PRESIDENT OF THE UNITED STATES, THE NATIONAL ENERGY PLAN (April 29, 1977).

27. Among the states which have conducted or are conducting residential time-of-day rate experiments are Arizona, Arkansas, California, Connecticut, New Hampshire, New Mexico, North Carolina, Ohio, Rhode Island and Vermont.

By 1977, the Carter administration and some members of Congress were convinced rate reform was an essential part of U.S. energy policy and that many states were not moving fast enough to implement such reforms. While federal action was seen as necessary to move the process along, the imposition of federal regulatory initiatives raised serious questions about federal power for an area in which the states traditionally had had complete responsibility. There were also practical questions whether any type of federal regulatory agency could determine effectively the desired electricity rates for hundreds of companies facing diverse cost, production opportunity, and consumption patterns. Title I of PURPA is the result of the intense political controversy that ensued between mid-1977 and late 1978. It is a compromise. Title I directs the states to examine a variety of ratemaking issues and establishes particular standards that should be investigated. However, the consideration and adoption of these standards remains largely up to the states, although there is the threat that states which do not comply may find themselves faced with further federal initiatives in a few years.

The debate over PURPA already has had at least one unfortunate administrative consequence. In the nearly two years between the first administration proposals and the time the President finally signed the bill, state rate reforms slowed considerably as the state commissions waited to see what the federal legislation locked like. Furthermore, the legislation that was passed appears to contain very strict requirements for grandfathering of states that already had considered and even implemented many of the federal standards that were established by PURPA. As a result, many states which already have made substantial progress may have to go through the time-consuming and costly public hearing process once again. While we will never know for sure, it is conceivable that this act has delayed rate reform in many states because of the reluctance of a few to move in the desired direction. This is especially true if reluctant states ultimately find it easy to fulfill the statutory requirements of "consideration" and "determination" without actually making any actual changes. Whether this will be the case depends on how far the federal government is willing and able to press the states in these areas, and what the states would have been willing to do on their own without the additional federal encouragement.

THE ECONOMIC FOUNDATIONS OF PURPA TITLE I

The provisions, conference report, and the legislative history leading to the passage of PURPA indicate that economic efficiency criteria are to be more important in formulating retail electric power rates. Except perhaps for the provisions for lifeline rates of Section 114,[28] there are two major principles which form the basis of the standards established in Title I. First, rates should be designed to reflect the *cost* of providing electric power to different types of customers. Second, where there are transactions costs associated with implementation such as metering costs, the benefits of any change in rate policy should be balanced against the costs of implementation.

Given these basic principles, the definition of *cost* that is to be used in considering and making determinations about the various standards is of primary interest. Except for issues associated with lifeline rates, the history of state rate reform initiatives and the debates that led to the passage of PURPA indicate that there was relatively little disagreement over the principle that "cost" should play a primary role in establishing retail electric power rates. However, there was considerable disagreement over how "cost" should be measured. On the one hand, economists and environmental groups argued efforts should be made to base electric rates on *marginal cost* principles. Indeed, it appears there was considerable pressure to provide explicitly for the use of marginal or incremental costs in the statute itself.[29]

On the other hand utilities, large industrial consumers, and state regulatory commissions favored language which would keep the definition of "cost" rather vague, with specific definitions to be provided by the individual state regulatory agencies. Proponents of this view apparently were motivated by two considerations. First, many utilities and industrial consumers (as discussed above) had opposed the use of marginal cost principles by state regulatory agencies and did not want the federal government to order state commissions to use marginal costs as their basic standard for ratemaking. If costs were to be used as the standard, they preferred to be able to use one of the myriad "fully allocated" historical cost methodologies traditionally used to allocate revenue requirements among the different classes of customers.[30] It was thought that these historical cost allocation techniques readily could be adapted to the more detailed cost justi-

28. 16 U.S.C.A. §2624 (Supp. 1979).

29. Some early drafts of the bill contained explicit references to marginal or incremental costs and a considerable amount of testimony was presented for and against this cost principle.

30. The term "fully allocated costs" refers to the process of distributing test year costs, including historical capital costs, among the various customer classes. A large number of specific allocational techniques have been used for performing such allocations. This process insures that there is no over or under recovery of historical costs since all allowed costs are allocated to one customer class or another. These allocational procedures do not necessarily reflect any causal relationship between current consumption and current costs of services.

fications of alternative rate structures, which the act required. Of course, since there are at least 20 different fully allocated cost techniques that have been used and no theoretical economic principles on which to base a choice among them, it would be easy to provide a cost justification for almost any rate structure.

The second source of opposition to the use of marginal cost in the statute apparently resulted from the general opposition of utilities, industrial consumers and state regulatory commissions to the expansion of federal regulatory authority into an area traditionally reserved for the states. The general view was that the choice of costing methodologies was an issue for the state regulatory commissions to decide, not the federal government. So opposition, especially by state regulatory commissions, did not necessarily imply a rejection of marginal cost principles. Indeed, many states already had determined marginal costs should be utilized in setting rates.

Section 115(a) represents a compromise between the positions taken by these various groups. The conference report makes it clear a state regulatory authority "has the discretion to select which costing methodology or methodologies it chooses, consistent with state law."[31] On the other hand, the specific factors that the statute suggests should be taken into account have a decidedly marginalist flavor to them. Section 115(a) recognizes that costs are likely to vary by time of day and season of the year, a concept which is based on the theoretical and empirical work on marginal cost pricing of electric power, not on the "fully allocated" cost approaches that utilities and commissions had traditionally used in this country. PURPA requires costing methodologies to try to "take into account the extent to which total costs to an electric utility are likely to change if (A) additional capacity is added to meet peak demand relative to base demand; and (B) additional kilowatt-hours of electric energy are delivered to electric consumers."[32] This is almost the definition of marginal cost. No other specific costing methodology is mentioned in either the statute or in the conference report. It is fair to say therefore that the statute has a strong preference for marginal cost principle. However, it is also clear from the conference report that the state regulatory authorities can abide by their own preferences regarding costing methodologies.[33]

Whatever the individual state commissions decide to do, marginal cost pricing principles provide the only consistent links between Title

31. *Supra* note 10, at 78.
32. 16 U.S.C.A. § 2625 (Supp. 1979).
33. H.R. REP. NO. 1750, 95th Cong., 2d Sess. 79-80, *reprinted in* [1978] U.S. CODE CONG. & AD. NEWS 7813-7814.

I's objective of promoting efficiency in the consumption and production of electricity and the six federal ratemaking standards established in Section 111. Marginal cost pricing theory leads directly to empirical guidelines for establishing rates based on the cost of service, time-of-day rates, seasonal rates and interruptible rates, all of which promote economic efficiency. There is no natural link between arbitrary historical cost allocation formulas and the six federal ratemaking standards. At best some historical allocation procedures may approximate the relative cost patterns indicated by the appropriate calculation of marginal costs. At worst, such allocation procedures may be used arbitrarily to justify virtually any rate structure that one chooses. It is unfortunate that the act does not recognize more explicitly the importance of using marginal cost as a basis for rate reform.

The importance of transactions costs also is made quite clear in the statute. PURPA recognizes that the implementation of various rate reforms cannot be achieved without cost. Cost effectiveness is identified as an important factor in the consideration of time-of-day rates, load management techniques and the standards for master metering. The act clearly implies that in making determinations in these areas the benefits from the reform must be weighed against the transactions costs. In the case of time-of-day rates, additional metering costs are the critical element on the cost side of this equation. The cost issue arises primarily in the case of residential and small commercial consumers whose single dial kilowatt-hour meters would have to be replaced with more sophisticated and expensive time-of-day meters. Additional metering costs are the critical element on the cost side of the master metering standard as well. The cost elements to be considered for load management are not specified, nor are load management techniques contemplated by the statute.

PURPA contains little guidance regarding the appropriate methods for evaluating the benefits associated with the implementation of these rate standards. Where guidance is given it is not clear that the indicated approach will promote economic efficiency. Consider the problem of evaluating the benefits of time-of-day rates. Prices for consumption during peak periods will rise and prices for consumption during off-peak periods will fall once such rates are implemented. It will cost more to consume during peak periods and in the long run, other things being equal, consumption should fall as consumers respond to higher prices. Similarly, consumption during off-peak periods should rise in response to the lower prices as a result of a shift from peak to off-peak consumption, as well as "new" consumption during the off-peak period that is encouraged by the lower prices. In the long run, innovation in appliance and capital stock should make it easier for consumers to exploit the off-peak rates, especially if economic energy storage media can be developed. As a result of these consumption shifts, utilities will have to build less peak capacity and use more efficient base load capacity more intensively, which would reduce the average cost of electricity. However, the net welfare gains to be achieved depend on a variety of demand and supply elasticities for which we have only imperfect knowledge. While the various residential rate experiments may give us some further information, the record to date indicates that we will get little more than qualitative agreement on the nature of consumer responses. In short, in the near future it is unlikely that state commissions are going to be in a position to make any more than educated guesses about the benefits from time-of-day rates, which are to be compared with the additional metering costs.

In the past the lack of detailed information about the relevant supply and demand elasticities has often been raised as a reason for delaying any reforms at all. But just because information is incomplete does not mean that we know nothing or that reasonable decisions cannot be made. From basic economic theory and existing empirical work we know the qualitative effects of time-of-day pricing, and in many cases can make reasonable lower bound estimates of the relevant demand elasticities. For large industrial and commercial customers who have very large bills and already have recording demand meters there is no issue. There are no additional metering costs and the direct efficiency gains from the time-of-day rates set equal to marginal cost must be positive. Time-of-day rates based on marginal cost will be cost effective for these customers as long as there is any demand elasticity whatsoever. Similarly, for large industrial and commercial consumers who do not now have the appropriate meters, but for whom the costs of the additional meters are trivial compared to the resources used to provide them with electric power, even with very small price elasticities the efficiency gains from time-of-day prices (if they are based on marginal cost) probably will be larger than the additional metering costs.

For smaller customers where the benefit/cost ratio is more uncertain a variety of approaches seem to make sense. Marginal cost-based time-of-day rates could be introduced gradually to customers with the largest annual consumption levels or with appliances that tend to be used during peak periods. The initial cutoff point could be based on reasonable lower bound estimates of the relevant demand elasticities. The consumption patterns of these customers could be followed over time and the time-of-day rates gradually extended to customers with less consumption as more information is obtained. An alternative and perhaps more attractive approach would be to set up the time-of-day rates on an optional basis, allowing individual consumers to make their own cost/benefit calculations by requiring that they pay for the appropriate metering devices if they choose to take the optional rates.

A number of things should be noted at this point. The efficiency consequences of any of these rate reforms can be evaluated only if the resulting prices either are set equal to marginal cost or if we know the relationship between the prices and marginal cost, since marginal cost is the relevant cost concept for efficiency calculations. If state commissions adopt alternative costing methodologies their efficiency consequences will be almost impossible to determine. And, even for those classes of customers which are not presented with time-of-day rates, an effort must be made to develop a rate structure which best approximates marginal cost, given the load characteristics of these customers and the available metering technology. For example, under optional time-of-day rates we would not want to provide residential customers with optional marginal cost-based time-of-day rates, if we did not also make an effort to calculate the traditional hour invariant residential tariff based on marginal cost considerations as well. Those customers who consume electricity less intensively at peak times and are most willing to adjust their consumption patterns will be the first to opt for the optional time-of-day rates. The load characteristics of the remaining customers in the class would then on the average be worse, and the time invariant rate should go up to reflect this deterioration and to encourage more customers to adopt the time-of-day rates.

The benefits to be achieved from any of the rate standards can not be evaluated by looking only at the reduction in peak demand and the value of capital and energy resources "saved" by such a reduction. The appropriate benefit calculation is more complicated. As prices are raised during the peak period and consumption declines, resources are saved during the peak period, but consumers also suffer a loss in welfare as a result of the increased prices. The net benefit from raising peak period prices to marginal cost will be approximately half of the resource savings. To this must be added the gain in consumers' surplus resulting from the reduction in prices off-peak less the additional costs of providing additional off-peak power.

PURPA gives more specific guidance for performing cost effectiveness analysis in the cases of master metering and load management techniques. Consumers occupying buildings with master meters face a consumption charge of zero.[34] As a result, it is presumed that they consume too much electricity. The costs of electricity consumption are somehow passed on to the users in their rents. But if consumers and owners of buildings behave rationally, we would expect to find master meters utilized only if the associated rates yield lower electricity costs than the individual meter alternative. This means either that the individual meters have a cost which is greater than what would be saved by going to individual meters (in which case the master metering provision would be inoperable), or that there is something wrong with the rates under which master metering customers are billed–in particular, that they do not reflect the marginal costs of serving these types of customers. If master metering represents an efficiency problem the way to resolve it is to make sure that the individual meter and master meter rates reflect the correct costs of service, and that building owners are given a choice between the two types of rates. This approach would take the problem of performing a cost benefit analysis off the backs of the state commissions by giving consumers the proper price signals.

The load management technique standard raises other problems. The history of government and utility thinking on load management indicates that many conceive of load management techniques as ways of forcing consumers to change their consumption patterns by fiat, rather than by giving them appropriate price incentives to do so voluntarily. For example, it has sometimes been suggested that weather-related peak capacity requirements could be reduced if some customers' loads could be curtailed during peak consumption periods.[35] In theory interruptible rates would provide the appropriate response more efficiently by allowing these customers who value peak consumption least (time-of-day rates can only imperfectly deal with weather-sensitive loads) to choose to be curtailed by offering a rate reduction which reflects the value to the system of reducing the load, which, in turn, will be a function of the marginal cost of peak consumption. Some combination of time-of-day rates and interruptible rates will almost always be superior to any form of forced load curtailment unless the metering costs for these rates are higher than the welfare losses associated with forced curtailment techniques.

However, PURPA's cost effectiveness standard provides no way to include consumers' valuation of receiving power at different times into the cost/benefit computation, or for comparing load management techniques with "voluntary" pricing techniques. On the con-

34. 16 U.S.C.A. §2625 (Supp. 1979).
35. *Id.*

trary, the cost effectiveness criterion is weighted heavily in favor of forced curtailment of power supplies without any consideration of the value of the power to the consumer. For Section 115 indicates that a load management technique would be cost effective if it reduces peak demand and if the cost saving *to the utility* is greater than the costs of the load management techniques.[36] Thus a utility which randomly curtailed customers on hot summer days instead of building enough capacity to serve them would save substantial production costs and incur little in the way of additional costs of "implementing" this load management technique. But this could prove to be an extremely costly policy from the viewpoint of consumers. This is simply an inappropriate test for cost effectiveness and is a blatant invitation to the inefficient and probably inequitable non-price rationing of power.

To sum up, the act's emphasis on cost effectiveness is consistent with considerations of economic efficiency. However, the act gives little useful guidance to state regulatory commissions for implementing such considerations and where guidance is provided it could easily lead to perverse results. Furthermore, the importance of marginal cost considerations pertains not only to the formulation of rates themselves, but also to the performance of the cost effectiveness standards established by PURPA.

The importance of efficiency considerations also is exemplified by the act's provisions for the review of fuel adjustment mechanisms. It is generally acknowledged that as a theoretical matter automatic adjustment mechanisms may provide disincentives to cost-minimizing behavior.[37] At least two types of distortions could result. First, automatic pass-through provisions for fuel costs might lead firms to favor excessively fuel-intensive generating equipment, especially in a world of inflation, fluctuating interest rates and regulatory lag (a reverse Averch-Johnson effect[38]). Second, firms may become less aggressive in seeking the least expensive fuel contracts if increases or decreases in fuel costs are fully and rapidly reflected in the rates. Given rapid inflation in fuel costs and regulatory lag, it does not seem feasible or desirable to eliminate automatic adjustment clauses entirely. It does, however, make good sense to encourage the state commissions to review these clauses every few years, as well as to

36. 16 U.S.C.A. §2625(c) (Supp. 1979).

37. *See, e.g.,* D. Baron & R. DeBondt, Fuel Adjustment Mechanisms and Economic Efficiency (1978) (unpublished).

38. The theoretical literature on rate-of-return legislation indicates that rate-of-return regulation provides incentives for utilities to use more capital-intensive techniques than would be efficient. *See* Averch & Johnson, *Behavior of the Firm Under Regulatory Constraint,* 52 AM. ECON. REV. 1052 (1962).

establish methods for monitoring utility behavior to insure that efficient fuel choice and fuel purchase policies are adopted. Developing the latter is not likely to be an easy task, however, and PURPA provides no guidance as to how the state commissions might go about doing so.

The PURPA provisions for lifeline rates and termination procedures also make it clear that economic efficiency is not the only criterion that the act anticipates state commissions will use in formulating rates. The strengths and weaknesses of redistributing income through the introduction of lifeline rates has been discussed in detail elsewhere.[39] PURPA requires that states consider lifeline rates as a way of providing "necessary" electricity service at "reasonable" rates and suggests that states can implement lifeline rates whether or not they pass the cost and efficiency criteria which characterize most of Title I. With regard to termination procedures the states are virtually required to adopt specific due process procedures, and to provide that service cannot be terminated if such termination would be especially dangerous to health and the customer is unable to pay for the service.[40] As a general matter, I do not believe that the electric power system is a particularly effective vehicle for redistributing income. There are reasonable humanitarian principles behind the termination procedures which make them difficult to object to, despite the efficiency losses that are associated with them. We should recognize, however, that it may be difficult to restrict the application of these procedures to cases in which there would be general agreement that they should apply.

PERSPECTIVE ON IMPLEMENTATION

As I indicated above the primary, direct impact of this legislation is to require states to consider various ratemaking standards and to make determinations regarding their applicability on a utility-by-utility basis. The act will prove to be valuable if it leads many of those states that had been reluctant to implement these types of rate reforms previously to do so now, based on appropriate cost and cost-effectiveness criteria. It will be a rather costly piece of legislation if the reluctant states go through the required hearing processes without changing their posture toward rate reform. This is true not only because of the resources wasted in conducting perfunctory "compliance" hearings. Those states which have been rather progressive in

39. *See generally* Pace, *The Poor, the Elderly, and the Rising Cost of Energy*, 95 PUB. UTIL. FORT. 26 (June 5, 1975); Berg & Roth, *Some remarks on residential electricity consumption and social rate restructuring*, 7 BELL J. ECON. 690 (1976).

40. 16 U.S.C.A. §2625(g) (Supp. 1979).

many of these areas are now likely to have to slow the process down by conducting the utility-by-utility public hearings for each of the rate standards that the act requires. It is indeed unfortunate that the act does not provide for more liberal grandfathering of states which have made serious and extensive efforts in many of these areas in the past few years.

In January 1979 EPRI conducted a survey of the previous rate design activities of all state regulatory commissions to compare them with the federal ratemaking standards provided for under Sections 111, 113, and 114 of PURPA.[41] Tables 1, 2, and 3 report the results of this survey based on responses from 43 of the 50 state regulatory

TABLE 1

State Regulatory Activities Related to Federal Ratemaking Standards Under Section 111 and Section 113 (number of states out of 43 responses)

	Considered	*Determined*	*Implemented*
Cost of service	34	27	27
Declining block rates	35	28	28
Time-of-day rates	29	18	15
Seasonal rates	32	29	29
Interruptible rates	30	26	26
Load control	25	16	14
Lifeline rates	30	22	7

Source: *Reference Manual and Procedures for Implementing PURPA* (Draft February 1979), Electric Utility Rate Design Study.

TABLE 2

State Regulatory Activities Regarding Standards Under Section 113 (number of states adopted)

	Adopted
Master metering	23
Automatic adjustment clauses	23
Customer information	18
Termination	24
Advertising	33

Source: *Reference Manual and Procedures for Implementing PURPA* (Draft February 1979), Electric Utility Rate Design Study.

41. ELECTRIC POWER RESEARCH INSTITUTE, REFERENCE MANUAL AND PROCEDURES FOR IMPLEMENTING PURPA, ELECTRIC UTILITY RATE DESIGN STUDY, Part 5 (1979) (draft).

TABLE 3

State Regulatory Activities Regarding Time-of-Day Rates
(number of states adopted)

Time-of-day or seasonal rates*	27
Costs by time period*	16
Marginal cost data used	10

*Permanent rates, not experimental rates

Source: *Reference Manual and Procedures for Implementing PURPA* (Draft February 1979), Electric Utility Rate Design Study.

commissions. With regard to some of the standards about two-thirds of the responding states indicate that they have considered and made determinations of the standards consistent with the PURPA guidelines. However, in two areas a much smaller proportion of the states indicate both consideration and determination. Very few states indicate both in all areas. It remains unclear whether the state commissions have really complied with the specific hearing requirements and the utility-by-utility considerations and determinations required by the act. While the Secretary of Energy ultimately will determine how strictly to interpret these requirements, my sense is that a considerable amount of additional public hearings are likely to be required in most states.

Of some concern is the fact that only 10 states have used marginal cost data in formulating time-of-day rates. As I indicated above, marginal cost data are essential for evaluating the efficiency and cost effectiveness of all of the standards established in Title I. The definition of cost made in Section 115 is certainly consistent with marginal cost, but the states are not required to use such a definition in their deliberations. Since DOE will appear as the intervenor in many of the public hearings that will occur as a result of the act, it is hoped the department will press the case for the use of marginal cost and appropriate calculations of the economic implications of the various rate standards. Another way the federal government could demonstrate the appropriate use of marginal cost data, the formulation of rates that economically conserve energy, and the correct methodologies for doing cost effectiveness calculations would be to implement these procedures as part of the federal interstate ratemaking process. It would be helpful if FERC could represent progressive leadership in this area, rather than following in the tradition of its previous incarnation, the Federal Power Commission.

Those states which do decide to adopt marginal cost pricing principles probably will find themselves faced with the problem of rationalizing their rate structure methodology with the traditional methods of determining the total revenues that the regulated firm is allowed to earn. Under prevailing ratemaking practice total revenues allowed are determined by applying the allowed rate of return to an original cost rate base.[42] The rate base is determined in most states as the sum of the original cost of all plant and equipment less accumulated depreciation.[43] For a variety of reasons this approach tends to underestimate seriously the true marginal cost of plant and equipment to the firm in many cases. As a result, rates based on marginal costs may yield total revenues greater than those permitted under traditional rate of return on rate base regulation.

Most states which have tried to implement marginal cost pricing principles have to confront this problem. There are two general approaches that could be taken to resolve it. The determination of the rate base and the general methodology for determining total revenues could be brought into consonance with the marginal cost pricing principles being used to determine the rate structure. For example, replacement cost and economic depreciation could be used in place of traditional accounting methods for determining the rate base. Such an approach would probably lead to substantial capital gains to utility investors if the marginal cost of capital were to be applied to such a rate base. As a result, I suspect that this approach is simply not acceptable politically. Presumably some kind of excess profits tax could be devised, but it would probably be distortional and has many potential problems associated with it.

The alternative that most state commissions appear to find attractive is to "back off" of marginal costs to minimize consumption distortions and reduce total revenues to the allowed level. This requires that the regulatory commission identify components of demand which are not very sensitive to price and to reduce the associated prices below marginal costs to meet the revenue constraint. One way to do this would be to reduce the customer cost component of the rate or charges for the first few units of consumption. Neither the decision to hook up to the electric power system nor consumption decisions on the margin is likely to be affected in this way. Coincidentally, the resulting rate would tend to look like a modest lifeline rate.

Over the next two or three years we will see whether the state regulatory agencies can respond appropriately and effectively to the challenge that Title I of PURPA represents. If special interest groups

42. *See* 1 A. KAHN, THE ECONOMICS OF REGULATION 20-58 (1970).
43. *Id.*

continue to convince the state commissions to serve their interests rather than the national objective, presumably there are enough electrons that cross state lines to make it possible for the federal government to take over the retail ratemaking process entirely. There are many reasons to believe that such an expansion of federal authority would be undesirable, so it is hoped that the states will take Title I seriously and continue to make the long overdue reforms in retail electric rates.