UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of Electricity Sales-for-Resale and Transmission Services	)))	Docket No. RM85-17-000 (Phase II)

COMMENTS OF THE

BUREAUS OF ECONOMICS, COMPETITION,

AND CONSUMER PROTECTION

OF THE UNITED STATES FEDERAL TRADE COMMISSION

WASHINGTON, DC 20580

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I. INTRODUCTION

The staff of the Bureaus of Economics, Competition, and Consumer Protection of the Federal Trade Commission (FTC staff) is pleased to submit the following comments in response to the Federal Energy Regulatory Commission's (FERC) Notice of Inquiry on Regulation of Electricity Sales-for-Resale and Transmission Services [50 Fed. Reg. 27604 (July 5, 1985)].[1] The central issue in this phase of the FERC proceeding is whether economic efficiency considerations require wholesale electricity prices to be based on average costs as is the case under current regulation or on marginal costs. Achieving the benefits of efficiency in wholesale electricity transactions is an important objective because many electric utilities purchase wholesale electricity from other electric utilities on a long term noninterruptible or requirements service basis.[2]

A utility's decision to purchase electricity from another utility or to produce it itself depends on the relative costs of

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[1] These comments reflect the views of the Bureaus of Economics, Competition, and Consumer Protection of the Federal Trade Commission. They do not necessarily reflect the views of the Commission or any individual Commissioner. The FTC, however, has voted to authorize the Bureaus to submit these comments.

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[2] "Requirements service is a long-term firm supply of capacity and [electrical] energy to meet all or part of another utility's load." 50 Fed. Reg. 27604 (July 5, 1985).

production and purchase. From the utility's perspective, it makes economic sense to produce electricity only when the cost of doing so is less than the price of purchasing it in the wholesale requirements market. If the price of purchasing electricity is less than the utility's cost of producing it, purchasing electricity benefits the utility and its customers; and, to the extent that the wholesale market price correctly reflects the marginal costs of producing the electricity, society also gains because electricity will be produced at lower cost.

Under present regulations, the historical average fully distributed cost or the average embedded cost of generating electricity[3] is usually the basis for the price paid to obtain requirement service electricity in wholesale markets in the United States. The central concern of the FERC proceeding is whether such average cost pricing is most beneficial to society or whether society would be better served by marginal cost pricing.

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[3] Average fully-distributed or embedded historical costs are estimated on the basis of past expenses. When a company produces only a single service or product, the average total cost of providing that service can be estimated by dividing total costs by total units produced or sold. When, however, a company provides two or more services, it will typically have certain costs that are caused only by one of the services, and other costs that are caused commonly or jointly by two or more of the services. In order to estimate an average fully-distributed cost for each service in the latter case, some method must be developed for apportioning those common and joint costs among each service. See: Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, Volume 1: Principles (New York: John Wiley and Sons, Inc., 1970), pp. 150-158. See also note 9.

This comment first addresses the general conceptual basis for determining whether the benefits of efficiency are more likely to be achieved by average cost or by marginal cost based prices. It concludes that basing wholesale market prices on marginal costs is superior to basing them on average costs. Then, the comment considers alternative methods to implement marginal cost pricing -- including peak load, two-part tariff, and Ramsey pricing.

II. MARGINAL COST PRICING AS A CONDITION FOR ACHIEVING EFFICIENCY

A. Efficiency As A Goal[4]

One of society's fundamental goals is to achieve economic efficiency, that is, to organize the production and consumption of goods and services to maximize social welfare or the sum of consumer's plus producer's surplus. This requires that the goods and services produced should be those desired by consumers, as indicated by their willingness to pay, and that such goods and services should be produced efficiently, that is at the lowest real cost to society. Economic efficiency also requires that exchanges among producers and consumers take place when such

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[4] The central issue in this FERC inquiry may be addressed by answering one of the questions posed in the FERC notice:

> 3 a. Would prices based on average embedded costs encourage greater efficiency in wholesale requirements markets than prices based on marginal costs?
> [50 Fed. Reg. 27609]

exchanges can make someone better off without making someone else worse off.

In order for goods and services to be produced and consumed efficiently, the prices consumers pay for goods and services must reflect the marginal cost of producing such goods and services. The marginal cost of a product is the additional cost attributable to the last unit of that product that is produced. A one unit reduction in consumption of a product such as electricity causes society's total expenditure on the production of electricity to fall by the marginal cost of the last unit of the good. Price is a measure of the value of a product to consumers, only when the price consumers pay equals marginal cost will they have an incentive to use the product efficiently.[5]

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[5] This principle can be illustrated using the following example. Assume that the marginal cost of producing another KWH of electricity is constant at 3 cents per KWH and that, given the current quantity of electricity consumed, the value of an additional KWH is 7 cents. On these facts, consuming an additional KWH is socially desirable because the value to the consumer is greater than the cost of producing the additional unit. Ideally then, additional KWHs should be produced and consumed until the value in use of the last such KWH is 3 cents. Such transactions, however, will not occur unless the price of each KWH is 3 cents. Were the price, for example, 5 cents, consumers would only purchase electricity until the last unit they purchase had a value to them of 5 cents. As a result, some KWHs for which consumers would be willing to pay the marginal cost of production would not be demanded or produced. This deviation between price and marginal cost prevents social welfare from being maximized in the use of electricity. Less than the optimal amount of electricity will be produced and consumed.

Similarly, welfare will not be maximized if the price charged is 1 cent per KWH. In such a case, welfare will not be maximized because consumers will purchase electricity for which they would not be willing to pay the marginal cost of production.

While the discussion so far has been couched in terms of consumption decisions, the principle that efficiency is furthered by setting prices equal to marginal costs is also true when the purchaser is a firm, like a utility, which then resells the product to a final consumer. There are two reasons why wholesale purchases of requirements electricity by utilities will be efficient only if the prices they pay correctly reflect marginal costs.

First, many buying utilities have the option to purchase electricity from more than one supplier. In order for these utilities to purchase from the most efficient supplier, electricity prices must reflect marginal costs. In deciding among alternative suppliers, utilities will buy requirements electricity from the supplier with the lowest price, all other conditions (such as reliability) being equal. If, however, prices do not correctly reflect marginal costs, they may not purchase from the supplier with the lowest marginal cost. In that case, it will cost society more to produce that electricity than was necessary, and economic efficiency will be impaired.

Second, buyers of requirements electricity have the option of generating their own electricity rather than purchasing from another utility. If wholesale prices do not correctly reflect marginal costs, prospective buyers might choose to produce electricity themselves when it would be less costly to society to have another utility generate the electricity and sell it to them. Conversely, if prices do not reflect marginal costs, buyers might purchase electricity when it would be less costly to society for the buying utility to generate it itself.

Further, in order for purchasers of goods and services to respond to prices in a way that will enhance economic efficiency, it is necessary for prices to be determined and made available to purchasers by the time consumption decisions are made. Consumers have no opportunity to adjust their consumption of electricity in response to prices if the prices they will be charged are not determined until after the electricity has been consumed. Thus, for example, it would be better to base rates on the expected marginal cost at different points in time rather than basing rates on an observed marginal cost if that can only be determined after consumption has occurred.

B. Short Run vs. Long Run Marginal Cost[6]

Having established the efficiency benefits of marginal cost pricing, the question still remains as to which concept of marginal cost is the the correct one to use. Economists discuss two different types of marginal cost: long run marginal cost -- the marginal cost of producing an additional unit of electricity when the utility can vary its capital stock -- and short run marginal cost -- the cost of producing an extra unit of output in

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[6] This section responds to another question posed in the FERC inquiry:

> 6. If wholesale requirements prices are based on marginal costs, should these prices be based on short-run or long-run marginal costs? Why? [50 Fed. Reg. 27609]

the short run, when the size or scale of plant is fixed.[7] Short run marginal cost (SRMC) is the correct cost measure to use in

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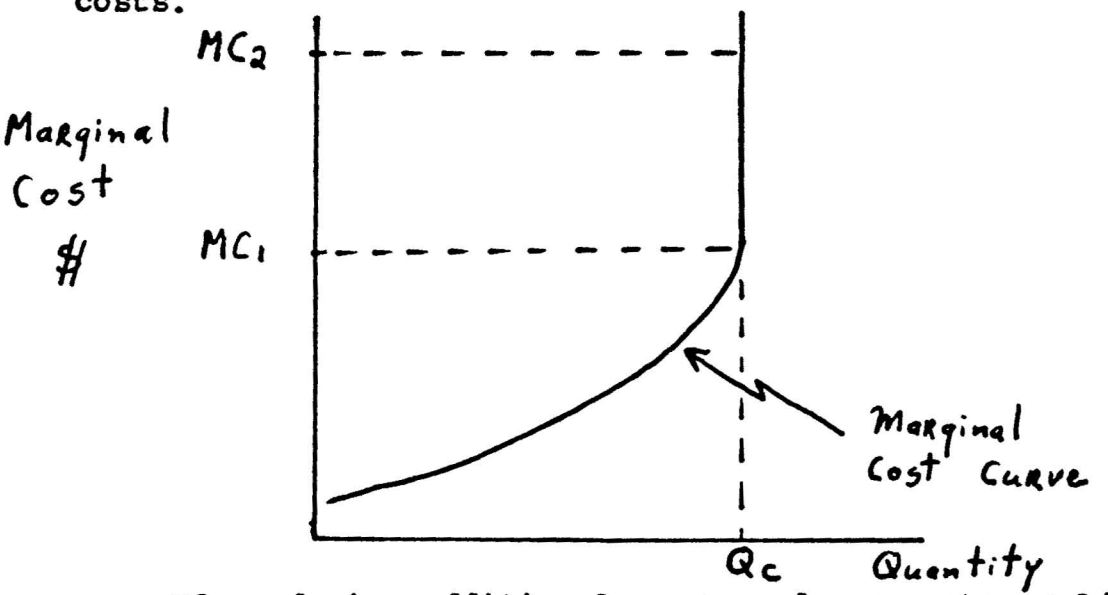
[7] The definition of short run marginal cost (SRMC) at a period of peak demand becomes somewhat unclear if a utility is operating at capacity during the peak period and, given its current capacity, cannot increase the quantity of electricity generated. This situation is pictured in Figure 1, where capacity is reached at a quantity Q_c when the short run marginal cost curve becomes vertical. At Q_c, SRMC can be defined as being any amount between MC_1, the additional cost of increasing output from $Q_c - 1$ to Q_c, and infinity. In such cases, it is appropriate to charge a price equal to some value MC_2 which exceeds MC_1. The proper level for such marginal cost-based-prices is discussed in Israel Pressman, "A Mathematical Formulation of the Peak-Load Pricing Problem," The Bell Journal of Economics and Management Science, 1 (Autumn 1970), pp. 304-326. If such cases arose in practice, we would include values like MC_2 in our definition of short run marginal costs.



If producing additional power reduces system reliability, it may be appropriate to include in SRMC a charge to reflect the cost this decreased reliability imposes on other consumers. Such reductions in system reliability may occur when a utility is operating above its rated capacity.

Since SRMC assumes that the capital stock employed in the generation of electricity is fixed, the cost of capital is not included in SRMC. However, with cost minimizing system dispatch, SRMC will equal or exceed average operating cost at all levels of output. Thus, some contribution will always be made toward covering fixed costs or covering the cost of capital. Suggestions for reconciling SRMC pricing with the requirement that investors be permitted to earn a fair return on their investment will be discussed in Section IV, Meeting Revenue Requirements.

setting prices.[8] When price equals SRMC, existing production capacity is utilized efficiently. The concept of long-run marginal cost is important for efficient capacity decisions.[9]

C. Efficiency and Average Cost Pricing

Under present regulations many electric utilities actually base their rates upon average fully-distributed cost or embedded

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[8] There is support for basing prices on short run marginal cost, according to Joskow and Schmalensee op. cit., pp. 80-81,

> . . . [A]n ideal pricing system for electricity would set prices equal to short run marginal cost of providing electricity at different voltage levels . . . . The appropriate general principle that we suggest is that prices should reflect marginal costs, taking appropriate account of metering costs and other contractual complexities.

Another study recommends that electric generation be deregulated and organized competitively to supply power to regulated common carrier transmission and distribution networks. That study also implies that prices must be based upon short run marginal costs.

> Efficient dispatch [of electricity] requires that only the least variable cost units are used at each moment . . . . We propose using a real-time competitive spot market to keep supply and demand in balance and guarantee least cost production for the system under deregulation. As demand rises [during the day], so will competitive price . . . .

Bennett W. Golub, Richard D. Tabors, Roger E. Bohn, and Fred C. Schweppe, "Deregulating the Electric Utility Industry: Discussion and A Proposed Approach," MIT Energy Laboratory Working Paper MIT-EL 81-043 WP (July 1981 revised August 1981), pp. 5-6.

[9] The short run marginal cost of producing any level of output is likely, of course, to depend on the quantity of capital the firm has invested in the production of electricity. In general, the greater the amount of capital, the lower the short run marginal cost of producing any quantity of electricity. We do not deal here with the issue of how to determine the optimal level of capital, but rather assume that the optimal capital stock is in place.

cost. For several reasons, such average cost based rates are unlikely to be efficient. First, the methods for estimating fully-distributed costs are inherently arbitrary[10] so that average fully-distributed costs, unlike marginal costs, do not accurately reflect cost causation. Second, at most levels of electricity production, average cost and marginal cost are likely to diverge. Under some circumstances the marginal cost of generating electricity will exceed the average fully-distributed cost, and in other circumstances marginal cost will be less than the average fully-distributed cost. When rates are based upon average fully-distributed cost rather than marginal cost and marginal cost exceeds fully-distributed cost, the price charged for electricity will be too low to achieve efficiency and will encourage excessive consumption of electricity. On the other hand, when marginal cost is below the fully-distributed cost, price will exceed the cost of generating those last units

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[10] Under an average fully-distributed cost measure, those costs that are caused by particular services are attributed to those services. However, other joint or common costs such as the capital costs of building power plants and transmission lines and corporate overhead expenses are divided up among all services under some essentially arbitrary accounting costing principal of fully-distributed costs, because they can not be unambiguously identified as being caused by only one service. Common costs may be distributed among all services on the basis of some shared unit of utilization such kilowatts, kilowatt hours, etc. Alternatively, they may be distributed among services in proportion to those costs that can be directly attributed to each service, or they may be distributed among services in proportion to gross revenues generated from each service. See: Ronald R. Braeutigam, "An Analysis of Fully Distributed Cost Pricing in Regulated Industries," The Bell Journal of Economics, 11 (Spring, 1980), pp. 182-196. See also note 3.

of electricity. This will lead to too little consumption of electricity. It is, therefore, important that prices reflect marginal cost so that electricity consumers will base their decisions on the actual costs of producing that electricity.

D. Wholesale vs. Retail Prices

In its notice, FERC specifically asked whether the efficiency arguments for basing prices on marginal cost rather than average fully-distributed cost still hold if final retail electricity sales are not based upon marginal costs.[11] It would be best to have all electricity rates, including retail rates, based upon marginal costs so that final retail customers could take into account the true costs of supplying extra units of electricity. However, it would be an improvement over current practice to have wholesale rates based on marginal costs, even if retail rates were not. When wholesale requirements rates are based on marginal costs, wholesale purchasers will receive correct price signals. They will therefore tend to buy their requirements electricity from the lowest marginal cost supplier and make efficient decisions concerning whether to purchase or to produce electricity themselves. Further, we believe that marginal cost pricing of wholesale requirements rates will tend

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[11] FERC's question is the following:

> 3 c. Should we establish wholesale electricity prices based on marginal costs in areas where retail rates are not based on marginal principles? [50 Fed. Reg. 27609].

to improve the economic efficiency of retail purchase decisions even when the retail rates are not based on marginal costs. If the price the utility pays for power more accurately reflects the cost of producing that power, the rates it charges, even if they are average cost based rates, should more accurately reflect the costs involved. Therefore, FTC staff recommends that wholesale rates be based upon marginal costs even where retail rates are not based upon marginal costs.

III. IMPLEMENTING MARGINAL COST PRICING IN WHOLESALE ELECTRICITY MARKETS

A. Time of Day or Peak Load Pricing[12]

Demand for electricity fluctuates substantially over the day, week, and season of the year. Typically, consumption is greatest in the middle of the day on Monday to Friday, during

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[12] This section responds to several questions posed by FERC:

> 1. Do the costs of providing wholesale requirements service vary systematically by time-of-use? If so, is there any reason why we should not establish prices for requirements service that vary by time of use? Are there any benefits from continuing to set prices that do not vary by time-of-use?
> 2 a. In determining whether to adopt time-of-use marginal cost pricing for wholesale requirements service, should we be concerned if any wholesale customers cannot reflect those time-of-use marginal cost prices in their retail rates? What harm would be done by adopting marginal cost pricing for wholesale requirements sales if those signals were not transmitted through to retail rates and/or if retail customers did not respond to these price signals?

the hottest months of the year because of air conditioning use, and during the coldest months of the year because of heating use.[13]

To generate electricity to meet such varying demand, utilities use a combination of generating plant sizes, types, and vintages. Nuclear and large coal fired steam generating plants typically have relatively high capital costs but relatively low operating costs. Hydroelectric plants also have high capital costs and very low operating costs. However, because its source of energy is falling water, the full capacity of a hydroelectric plant is available only during seasons when its reservoir holds a substantial amount of water. On the other hand, small gas turbine and internal combustion generators typically have relatively low capital costs but relatively high operating costs. Generally, electric utilities use large capital-intensive hydroelectric, nuclear, and coal burning power plants as the source for base electricity loads, and less capital-intensive but higher operating cost gas turbine and internal combustion plants during periods of peak demand.[14]

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[13] As a result, the size of the peak system demand will depend not only upon season of the year, day of the week, and time of day, but also on the outdoor temperature on particular days. Thus it might be desirable to make electricity rates a function of temperature as well as season of the year, day of the week, and time of day. See, e.g., Daniel F. Kohler and Bridger M. Mitchell, Response of Residential Time-of-Use Electricity Rates: How Transferable Are The Findings? (Santa Monica: The Rand Corporation, October, 1983).

[14] Because utilities operate a variety of kinds of plants in different sizes and vintages, the marginal operating costs of supplying electricity varies by season of the year, day of the week, and time of the day. For example, in 1973 one eastern

(footnote continued)

To achieve efficiency, prices must reflect the difference in marginal costs between peak and off-peak periods. Only when prices in peak periods are higher will users have incentives to reduce peak period electricity use, perhaps shifting some use to off-peak periods.[15] Similarly, only when wholesale rates reflect peak marginal costs will purchasing utilities have an incentive to search for lower cost alternatives.[16]

That it is efficient to vary electricity rates with the time of day and season of the year is well known. Many European utilities have used time of day pricing for decades. France, for

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(footnote continued)

U.S. utility had incremental fuel costs for different generating facilities that ranged from 0.33 to 0.95 cents per KWH. A 1976 study estimated that in 1970 a utility in Ithaca, NY, had marginal costs that ranged from about 0.2 cents per KWH for its base load electricity to about 3.2 cents for its peak load electricity. See: Paul L. Joskow and Richard Schmalensee, Markets For Power: An Analysis of Electrical Utility Deregulation, (Cambridge: Mass., MIT Press, 1983), pp. 45-58; Edward Berlin, Charles J. Cicchetti and William J. Gillen, Perspective On Power: A Study of the Regulation and Pricing of Electricity, (Cambridge, Mass.: Ballinger Publishing Co., 1974), pp. 34-35; Charles R. Scherer, "Estimating Peak and Off-Peak Marginal Costs for An Electric Power System: An Ex Ante Approach," The Bell Journal of Economics, 7 (Autumn, 1976), p. 597.

[15] However, a utility that sets higher prices for peak usage must be careful not to simply shift peak demand to time periods just before and just after the period of peak prices. Indeed, it may be necessary to go through several rate setting iterations in order to be sure that the final period of peak usage is still the period with the highest price. See Elizabeth E. Bailey and Lawrence J. White, "Reversals in Peak and Off-peak Prices," The Bell Journal of Economics and Management Science, 5 (Spring 1974), pp. 75-92.

[16] See, e.g., Bridger M. Mitchell, Willard G. Manning, Jr., and Jan Paul Acton, Peak Load Pricing: European Lessons for U.S. Energy Policy, (Cambridge, Mass.: Ballinger Publishing Co., 1978), pp. 1-52; 89-202.

example, has used time of day pricing for nearly 30 years. In 1975 the French tariff had a peak energy charge for large industrial customers for 4 hours per day between November and February. This peak rate was more than three times the rate during the lowest demand off-peak hours.[17] Many other European utilities now use time of day pricing.[18] The experience of those utilities indicates clearly that users respond to higher rates in peak periods by reducing consumption in those periods and increasing it in off-peak periods.[19] Such shifting of

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[17] Edward Berlin, Charles J. Cicchetti, and William J. Gillen, op. cit., pp. 29-51; M. Boileux, "Peak Load Pricing," Journal of Business 33 (April, 1960), pp. 157-179; and Bridger M. Mitchell, Willard G. Manning, and Jan Paul Acton, op. cit., p. 68.

[18] James G. Goggis, "An Electricity Experiment in England and Wales," and Yves Ballasko, "A Contribution to the History of the Green Tariff: Its Impact and Its Prospects," both in New Dimensions in Public Utility Pricing, edited by Harry M. Trebing (East Lansing: Michigan State University, MSU Public Utility Studies, 1976), pp. 461-477, 478-492.

[19] For example, in France, it was found that electricity usage in cement plants dropped by about 50 percent in peak hours, metal-alloy plants by about 80 percent, and in petroleum refining firms dropped by 90 percent in the peak price period. See: Bridger M. Mitchell, Willard G. Manning, and Jan Paul Acton, op. cit., pp. 89-107. See also: A.K. Miedema, S.B. White, C.A. Clayton, and D.P. Lifson, "Experimental Time-of-Use Electricity Prices," in Issues in Public Utility Regulation, edited by Harry M. Trebing, MSU Public Utilities Papers, (East Lansing: Michigan State University, 1979), pp. 51-72; Clive W.J. Granger, Robert Engle, Ramu Ramanathan, and Allan Anderson, "Residential Load Curves and Time-of-Day Pricing," Journal of Econometrics 9 (1979), pp. 13-32; Anthony Lawrence and Steven Braithwait, "The Residential Demand for Electricity With Time-of-Day Pricing," Journal of Econometrics 9 (1979), pp. 59-77; Lester D. Taylor, "On Modeling The Residential Demand for Electricity by Time-of-Day," Journal of Econometrics 9 (1979), pp. 97-115; Scott E. Atkinson, "Responsiveness of Time-of-Day Electricity Pricing: First Empirical Results," Journal of Econometrics 9 (1979), pp. 79-95; Robert M. Spann and Edward C. Beauvais, "Econometric Estimation of Peak Electricity Demands," Journal of Econometrics 9 (1979), pp. 119-136.

electricity usage from peak to off-peak periods decreases the cost of supplying electricity in the short run by decreasing the need to employ high operating cost peaking plants and in the long run by postponing the need to construct additional generating capacity.[20]

As discussed in section II, achieving the benefits of efficiency requires marginal cost pricing of wholesale transactions even when marginal cost pricing is not employed in retail rate design. Because time of day pricing is one way to make rates more accurately reflect the marginal costs of providing service it is appropriate to use time of day pricing for wholesale transactions even if it is not used for retail sales.

Thus, the FTC staff strongly recommends that FERC encourage, if not require, electric utilities subject to its jurisdiction to use peak load or time of day pricing in the sale of requirements service.

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[20] Of course, such an analysis is valid only when the benefits of time of day pricing exceed the costs of using time of day electric meters. While that is an empirical question, it seems reasonable to believe that with respect to wholesale transactions the benefits of metering would far outweigh the costs. One study estimated that for a sample of about 4,000 industrial and commerical customers, the annual cost of using time of day meters would be $65 per customer per year; whereas the welfare gains from time of day pricing would be about $1,000 per year per customer. R.E. Park and J.P. Acton, Response To Time of Day Electricity Rates by Large Business Customers: Initial Analysis of Data for Ten U.S. Utilities (Santa Monica: The Rand Corporation, September 1983), Rand Report R-3080-HF/MD/RC.

B. Two-Part Tariffs[21]

One rate structure that has been used widely in wholesale electricity markets in the United States is the so-called two-part tariff.[22] Under a two-part tariff, the price is made up of a usage charge for each kilowatt hour of electricity and a separate demand charge for the maximum level of demand.[23] Several reasons have been advanced for using a two-part tariff that includes a capacity-based demand charge. First, some commentators have suggested that such a two-part tariff is

[21] The actual questions posed by FERC are:

> 10 a. Should we continue to employ the two-part rate form for wholesale requirements sales? Why?
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> b. If so, what billing determinants for assessing demand charges to customers would most effectively promote efficiency? (Possible options include, e.g., noncoincident peak demands; coincident peak demands, established at the end of the billing period; and purchases during a period, announced in advance, when the seller's capacity utilization rate is expected to exceed some specified level.) State the reasons for your answer.
>
> d. Alternatively, should we abandon the two-part rate form in favor of time-varying one-part rates? Why or why not? What benefits do two-part rates have over one-part rates? [50 Fed. Reg. 27610]

[22] This discussion deals only with two-part tariffs where one-part of the tariff is related to capacity utilized. It does not deal with two-part tariffs where one-part is a flat charge that is unaffected by the quantity of electricity purchased by the customer in either peak or non-peak periods. That type of two-part tariff is discussed on pages 21-23.

[23] In the case of partial requirements customers, demand charges are based upon a contract which specifies the maximum amount the purchaser is permitted to demand at any point in time. In the case of full requirements customers, the demand charge may be based on a so-called "demand ratchet" which means that customers will be charged on the basis of the greater of their maximum demand in the current month, or some fraction, such as 90 percent, of their maximum demand in the previous 11 months.

necessary to achieve efficiency during peak demand periods.[24] As we have discussed above,[25] price in each time period should be set equal to short run marginal cost (SRMC). If a separate cost-of-capital charge were added to SRMC during peak periods, price would exceed the added cost of producing the electricity demanded. This would result in less consumption of electricity than is efficient. Therefore, in the view of the staff of the Federal Trade Commission, the correct pricing scheme to achieve efficiency would not involve a two-part tariff.

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[24] The conclusion that the price of electricity during a period of peak demand should be equal to marginal operating cost plus marginal cost of capital appears to have come from economic models that assume that operating expenses are not affected by the quantity of capital available to a utility and that the utility's capital stock is fully employed at periods of peak demand. See, e.g., Paul L. Joskow, "Applying Economic Principles to Public Utility Rate Structures: The Case of Electricity," and Charles J. Cicchetti and John L. Jurewitz, "Public Utility Pricing: A Synthesis of Marginal Cost, Regulatory Constraints, Averch-Johnson Bias, Peak Load and Block Pricing," both in Studies in Electric Utility Regulation, edited by Charles J. Cicchetti and John L. Jurewitz (Cambridge, Mass.: Ballinger Publishing Co., 1975), pp. 17-72, 89-117.

The assumption that operating cost is independent of the quantity of capital a utility employs appears to be particularly unrealistic when one is discussing short run costs. The short run marginal cost of generating one million KWH will be lower if a utility has base load capacity rated at one million KWH than if it only has base load capacity rated at 500,000 KWH. Further, it seems unlikely that a utility cannot generate additional power even in peak periods. Rather, even at periods of peak demand, a utility will normally possess backup capacity to permit it to expand production, although only at a high marginal cost. In this more realistic model where operating costs are a function of capital stock and output can be expanded even in peak periods, it can be shown that optimal pricing involves pricing at short run marginal cost in all periods. See Israel Pressman, op. cit.

[25] See pages 6-8.

Second, although a two-part tariff will not be efficient, some kind of two-part tariff may be needed in some situations where a utility's capital investment decisions depend on whether or not a particular customer will buy its electricity needs from the utility.[26] Such a tariff could be used to ensure that such a customer pays for capacity constructed to serve him. If such large customers can choose among two or more utilities from whom to purchase electricity or instead can choose to generate their own electricity, a one-part tariff that depends solely on the quantity of electricity purchased in a particular period may lead to inefficient investment decisions. In such cases, a two-part tariff may be warranted even though to some degree it may sacrifice efficiency in short run purchasing decisions.

A utility may only be able to provide another utility's requirements needs by building additional generating capacity. However, it may not be willing to add the capacity unless it can be assured that the utility for whom the capacity is constructed will pay the costs of the additional capacity. Without such assurances, the selling utility could find itself with added capacity and no purchaser for the electricity that this capacity could generate.

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[26] A particular customer may affect a utility's investment plans if sales to that customer would cause the utility to add generating capacity. However, sales to a particular customer may also affect investment plans even if they do not affect the utility's total generating capacity. Whether a utility sells to a particular customer may affect the mix of generating equipment between base-load and peak load capacity. Sales to a particular large buyer may also require the utility to build additional distribution lines to reach the customer.

To avoid this possibility, the purchasing utility could give necessary assurances through a contract that includes a two-part tariff with a "reservation demand" component. Under such a contract, the purchasing utility would pay some of the cost of the capacity built to serve it even if the utility did not utilize the capacity. With such a contract, the utility building the capacity would not bear as much risk of an underutilized plant, and the capacity necessary to serve customers is more likely to be constructed. Such a risk sharing contract can enhance efficiency.

FTC staff, therefore, recommends that FERC permit use of such two-part tariffs where a utility builds additional capacity in order to serve a particular purchasing utility. Failure to permit such contracts could mean that needed and efficient capacity may not be constructed.

IV. MEETING REVENUE REQUIREMENTS

Electric utilities that base their rates upon marginal cost may lose money in some cases.[27] In such a case, the utility will be unable to raise the capital needed to maintain or expand its facilities, and utility service will decline. In other situations, rates equal to short run marginal cost may result in

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[27] The question of whether marginal cost pricing will generate the necessary revenue to cover a utility's revenue requirements can arise any time marginal cost pricing principles are employed. They can arise if rates vary by time of day or if they do not.

the utility making profits in excess of what society believes is appropriate for a regulated utility.[28]

There are various methods for dealing with this problem, and several of these methods may be used simultaneously.[29] One is to set price equal to an average embedded or fully-distributed cost measure. However, as discussed above, such a procedure introduces economic inefficiency into purchasing and production decisions. Another is to employ a two-part tariff that levies a charge on each customer that does not vary with the quantity of electricity consumed. A third solution, which may be used in combination with the second method, is to set price above or

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[28] It should be noted that when marginal cost exceeds average cost, it does not follow that it is economically efficient to lower price below the point where marginal cost equals price. Even in a competitive industry with many firms and easy entry, some firms may earn inframarginal rents when they produce output up to the point where marginal cost equals price. These firms earn those rents because their average costs are lower than marginal cost, not because they have any monopoly power.

When a public utility sets price equal to marginal cost in situations where marginal cost exceeds average cost, it will also be earning inframarginal rents. It will not be exercising the kind of monopoly power that would be indicated if price were above marginal costs. Hence, there is no efficiency reason for forcing its price down below marginal cost. However, under traditional utility regulation principles a utility is only entitled to cover all its expenses including a "fair" return on historical capital. Hence the utility may not be allowed to earn all the rent implied by setting price equal to marginal cost, even though it might be efficient to allow it to do so. Thus, in this case Ramsey pricing, discussed in section B, is a method for reducing the utility's revenues when marginal cost exceeds average cost and when the utility is subject to rate of return regulation. Nevertheless, in this situation it would be <u>efficient</u> to allow the utility to retain those rents and not impose Ramsey pricing.

[29] See, e.g., Edythe S. Miller, "Rate Structure Reform: A Review of the Current Debate," <u>Journal of Economic Issues</u>, XII (September 1978), pp. 609-626.

below short run marginal cost using a Ramsey pricing rule. These alternatives will be discussed below.

A. Lump-Sum-Charge Two-Part Tariffs

When setting price equal to marginal cost fails to yield sufficient revenue to cover all of the utility's expenses, a particular kind of two-part tariff could be used to raise the revenue the utility needs to remain in business.[30] Such a two-part tariff would consist of a usage charge -- the price paid for each KWH of electricity consumed -- equal to short run marginal cost plus a lump-sum-charge that was a constant amount for each customer and therefore independent of the quantity of electricity consumed or the maximum level of demand.[31] Provided the charge was not so large that some buyers found that they were better off to avoid the charge by not buying any electricity at all from

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[30] See: Walter Y. Oi, "A Disneyland Dilemma: Two-Part Tariffs For a Mickey Mouse Monopoly," Quarterly Journal of Economics, 85 (February 1971), pp. 71-96. There is a conceptually equivalent solution to the problem of excess revenues resulting from marginal cost pricing. In such a case, the utility could provide each customer with a lump-sum rebate that did not depend on the quantity of electricity consumed.

[31] In effect the lump-sum electricity charge would be a lump-sum tax on all users of the utility's electricity. It is well known that such lump-sum taxes do not affect consumption decisions. See, e.g., Richard A. Musgrave, The Theory of Public Finance (New York: McGraw-Hill Book Company, 1959), pp. 136-147. Note that this kind of two-part tariff is different from that used by many electric utilities today. Electric utilities that now use a two-part tariff have a demand charge that is based upon the highest amount of electricity demanded in some time period. Hence, they do not use a lump-sum tax approach. See 50 Fed. Reg. 27610.

this utility,[32] such a charge would have no impact on the purchase of electricity. Since price would be equal to marginal cost, each customer would purchase the same amount of electricity as it would if there was no lump-sum charge. Thus, such a two-part tariff would be a method for raising additional revenue when needed to satisfy a utility's revenue requirements while not affecting decisions of how much electricity to purchase and from whom.

There may, however, be a problem in attempting to implement such a lump-sum tax approach. The lump-sum-charge must be set high enough to extract some of the surplus from the purchaser, but not so high that it causes the purchaser to turn to another energy source altogether. It may be more difficult to estimate the appropriate lump-sum-charge than it is to estimate the data needed to implement a Ramsey pricing rule.[33] The Ramsey pricing rule, which is discussed in the next section, depends upon price elasticities of demand for additional units of output, whereas

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[32] The technical condition that must be satisfied in order not to cause any consumers to forego purchase of electricity from a utility is that the lump-sum-charge must be no greater than the smallest surplus of any consumer. See Walter Y. Oi, op. cit., pp. 81-88.

[33] See: Paul L. Joskow, op. cit., pp. 25-26. In order to determine a lump-sum-charge that will not distort consumption decisions, it is necessary to know the entire shape of the demand function for each consumer. Ramsey pricing only requires knowledge of the elasticity of demand in the vicinity of the output at which price equals marginal cost. While estimating the elasticities needed for Ramsey pricing is by no means trivial, it seems likely to be less burdensome than the data requirements for determining the lump-sum-charge for a two-part tariff.

this two-part tariff requires a selling utility to know how large a lump-sum-charge should be for each service before it would discourage a buyer from buying that service. Hence, it may not be practical to use the lump-sum-charge approach.

B. Ramsey Pricing[34]

Ramsey pricing provides a second best solution[35] to the problem of retaining the desirable economic efficiency properties of marginal cost pricing while still enabling a utility to earn its allowed rate of return in two kinds of situations: when marginal cost is below average fully-distributed cost so that marginal cost pricing would cause the utility to incur losses; and when marginal cost is above average cost so that marginal cost pricing would generate "excessive" profits.[36]

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[34] This section responds to another FERC question:

> 7 a. Given that the revenue requirement would be based on embedded costs, what adjustments should be made to marginal cost prices so as to cause the least distortion to efficiency and avoid the Federal Power Act proscription against undue discrimination? Explain your answer.
>
> b. Would a pricing system based on average embedded costs encourage greater efficiency in wholesale requirements markets than a pricing system based on marginal costs with such adjustments? [50 Fed. Reg. 27609]

[35] By a second-best solution, we mean that allocation of resources that maximizes social welfare while at the same time satisfying the utility's revenue requirement. Such a solution is "second best" because it requires prices to deviate from marginal cost, which would provide the best allocation of society's resources.

[36] On the problem of "excessive" profits, see footnote 28.

A firm will not enter a market unless it expects production to be remunerative; and a firm eventually will exit a market if production is no longer remunerative. Thus, to ensure that production will occur, the revenue expected from production must at least cover all costs of production. In some circumstances, marginal cost pricing using one-part or two-part tariffs can lead to a combination of price and output that does not generate sufficient revenue for a utility to cover all of its costs. In such a case, marginal cost pricing renders production unprofitable. Like average cost pricing, the Ramsey pricing strategy was designed to provide enough revenue to permit profitable production. Unlike average cost pricing, the Ramsey pricing strategy minimizes the adverse effect on social welfare that results when price exceeds marginal cost.

The basic concept of Ramsey pricing is as follows: When marginal cost pricing is unremunerative, Ramsey pricing dictates that prices be raised above marginal cost for each service the utility provides in inverse proportion to that service's demand elasticity.[37] Thus, the increase in price above marginal cost, as a proportion of marginal cost, should be greatest for the service whose demand is most inelastic. By pricing in this way, Ramsey pricing minimizes the adverse impact

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[37] Edward E. Zajac, Fairness or Efficiency: An Introduction to Public Utility Pricing (Cambridge, Mass.: Ballinger Publishing Co., 1978), pp. 21-32. Ramsey pricing was originally developed by Frank Ramsey, in "A Contribution to the Theory of Taxation," The Economic Journal, 37 (March, 1927), pp. 47-61.

on social welfare of prices that are above marginal cost while providing enough revenue to make production attractive.[38]

Ramsey pricing may be illustrated using the following diagrams. Assume that a utility provides two different services, (A) and (B), and that demand for service (A) is more elastic than demand for service (B). These two services could be electric service during a period of peak demand and service during an off-peak period or they could be service to different classes of

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[38] See: William J. Baumol and David F. Bradford, "Optimal Departures from Marginal Cost Pricing," American Economic Review, 60 (June, 1970), pp. 265-273. The conclusion about the social welfare impact of the Ramsey pricing strategy can be explained by analogy to market power concepts. When market power is exercised, price is raised above marginal cost, output produced will be smaller than when price equals marginal cost, and social welfare is not maximized because some consumers cannot purchase units of output even though the price they would be willing to pay exceeds the marginal cost of producing such output units. All else being equal, the loss in social welfare is directly related to the extent of output restriction and the deviation between price and marginal cost; the greater the output restriction and the greater the deviation between price and marginal cost, the greater the welfare loss.

The fundamental concept that is the basis for Ramsey pricing is that the welfare loss caused by price increases necessary to make production remunerative can be minimized by raising prices more for services whose demand is relatively inelastic than for services whose demand is relatively elastic. Hence, Ramsey pricing raises prices relative to marginal cost most when it will have the least impact on output, and raises prices least relative to marginal cost when it will have the biggest impact on output.

It should also be noted that Ramsey pricing is different from the price discrimination behavior of an unregulated profit maximizing monopolist. The unregulated monopolist also raises price most above marginal cost where demand is most inelastic, but the unregulated monopolist is attempting to maximize profits. In contrast, the Ramsey pricing utility only raises price above marginal cost sufficiently to cover its revenue requirement. The prices of the Ramsey pricing regulated utility should be generally lower than the prices chosen by the unregulated profit maximizing monopolist.

customers, e.g., residential and commercial customers. Also assume, for simplicity, that the marginal cost of supplying services (A) and (B) is the same and is constant across the relevant range of output.

If the utility sets its rates equal to marginal cost, it will set price P_1 and sell Q_{1A} units of service A, and it will set price P_1 and sell Q_{1B} units of service B. Suppose, however, that at the price P_1, the firm does not generate sufficient revenue to cover its revenue requirement. How should the utility set its prices for services A and B? One possibility would be for the firm to respond by raising its price by equal amounts for both services to P_2 in both markets. In that case, the utility would sell Q_{2A} units in market A, and Q_{2B} units in market B. But because demand for service A is much more elastic than demand for service B, the quantity sold of A would fall by much more than the quantity sold of B.

An alternative that would have the least adverse impact on social welfare would be to raise price for each service so that the quantity demanded declined by equal proportions in each market.[39] For example, price might be raised to P_4 in market B, and only to P_3 in market A. This would yield an equally proportionate decline in the output in each market, and therefore would lead to the smallest decrease in social welfare consistent

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[39] See Paul L. Joskow and Richard Schmalensee, op. cit., pp. 88-90, 164-165.

Diagram A (Elastic Demand)

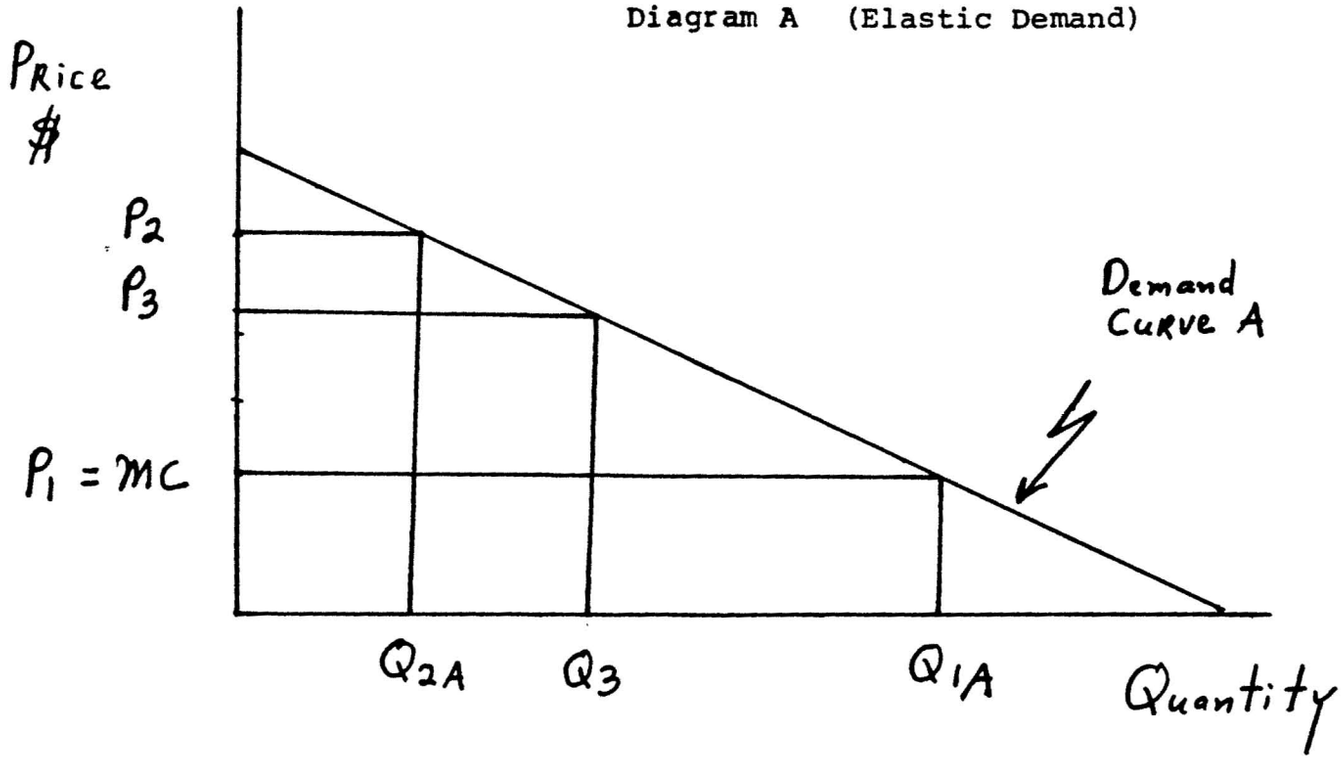
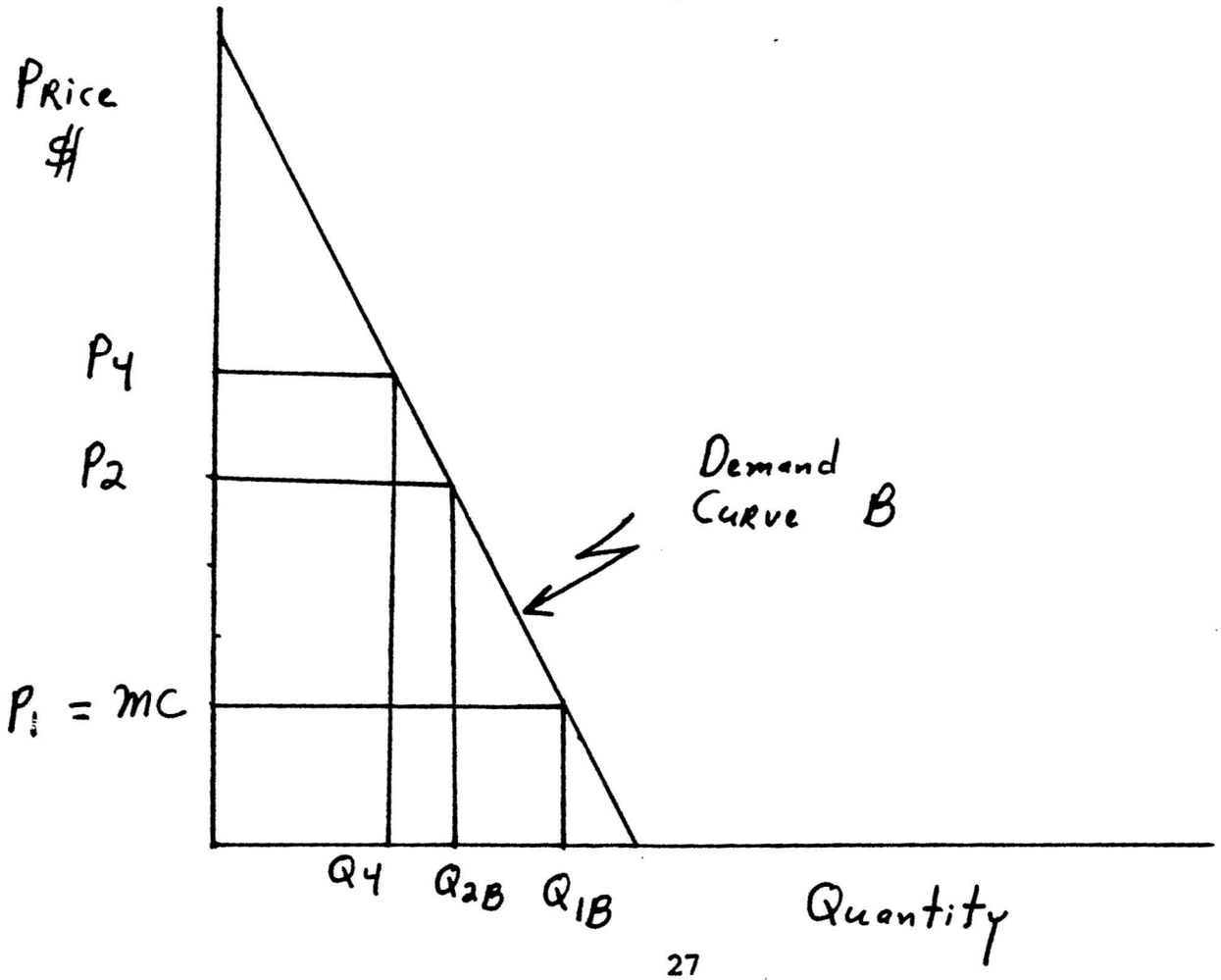


Diagram B (Inelastic Demand)



with meeting the utility's revenue requirement.[40] Note that the decline would be accomplished by raising price in market B by more than the price in market A. This general concept, that it is efficient to use Ramsey pricing, given that a utility is subject to rate of return regulation, will hold even if marginal costs are not the same for services A and B.

As we mentioned above, Ramsey pricing rules are symmetrical. In other words, in situations where marginal cost pricing would generate excessive revenue, prices should be decreased below marginal cost. Prices should be decreased most for the services where demand is most inelastic.[41] This will cause the smallest

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[40] "All output [should] be reduced by the same proportion from the quantities that would be demanded at prices equal to the corresponding marginal costs." William J. Baumol and David F. Bradford, op. cit., p. 267.

[41] Strictly speaking, the derivation of the inverse elasticity of demand rule depends upon the following assumptions concerning the services provided by the utility : (1) The cross elasticity of demand between the services is zero; (2) The cross elasticity of demand is zero between those services and other goods and services in the economy whose prices differ from their marginal costs; (3) The provider of those services is small enough that it is a price taker in the purchase of inputs and hence has no impact on input prices; (4) The prices charged for thse services do not affect the quantities of any other goods or services that have negative or positive externalities; (5) Income distribution is not affected or can be ignored because the marginal social utility of income is the same for all consumers; and (6) The electric utility can meet all the demands for its services at the prices that it charges for those services. See, e.g., William J. Baumol and David F. Bradford, op. cit., pp. 269; and Bruce M. Owen and Robert D. Willig, "Economics and Postal Rate Pricing Policy," in The Future of the Postal Service, edited by Joel L. Fleisman (Praeger: 1983), pp. 227-246.

distortion in the price-output combination relative to the ideal case in which price equals marginal cost.[42]

Hence, in situations where marginal cost pricing would generate insufficient or excessive revenues, and assuming that a utility is subject to rate of return regulation, we strongly recommend that FERC consider the use of a lump-sum-charge two-part tariff or Ramsey pricing as an alternative to average fully-distributed cost pricing.

V. CONCLUSIONS

FTC staff recommends that FERC encourage, if not require, the use of marginal cost pricing and peak load pricing in requirements sales of electricity. We also suggest that FERC encourage states to implement peak load or marginal cost pricing in their retail rates. While efficiency would be greatest if all rates were based on marginal costs, we do not believe that the failure to base retail rates on marginal costs should cause FERC to refrain from basing wholesale rates on marginal costs. The correct marginal cost concept on which to base electric rates is short run marginal cost. If setting price equal to short run marginal cost does not produce sufficient revenue to meet a utility's revenue needs, we recommend that FERC utilize a lump-sum-charge two-part tariff or a Ramsey pricing scheme to raise the necessary revenue.

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[42] Charles J. Cicchetti and John L. Jurewitz, op. cit., pp. 89-117.