Recovery of Joint Costs in a Competitive Environment

Sanford V. Berg
Florida Public Utilities Professor
College of Business Administration
P. O. Box 117142
University of Florida
Gainesville, FL 32611

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Abstract

In competitive industries, overhead or joint costs cannot be "allocated;" they must be "recovered where they can" based on a rate-making philosophy that recognizes this fact. This paper describes the basic issues and problems of recovering these costs, with special reference to electric utilities in an increasingly competitive environment.

One approach is to adopt Two-Part Pricing schemes, one reflecting capacity and distribution system charges and the other based on on-peak and off-peak energy costs. This eliminates distortions caused by average cost pricing, enabling customers to face the true costs of additional electricity purchases. Retail municipal utilities have incentives to create contracts with their suppliers that better reflect cost-causation. Integrated utilities could base the capacity and system charge price on a Historical Customer Baseline (HCB), so that such customers continue to contribute a "share" of overhead (or non-usage sensitive) costs. On-peak and off-peak prices are then set at incremental cost. Cost recovery is achieved via appropriate calculation of the monthly fee. Of course, if competitors can offer a better "deal," the HCB would need to be modified to minimize uneconomic bypass of the municipal utility.

A second approach focuses on differential demand elasticities. Customers who have demands which are insensitive to price have few alternative sources of supply. Higher prices to these "inelastic" demanders represent one way to obtain revenues that can be applied to shared resources (overhead costs). While Ramsey Pricing (the technical term for this approach) raises political issues, the outcome may be preferable to losing those customers who face competitive alternatives (including cogeneration).

Recovery of Joint Costs in a Competitive Environment

by Sanford V. Berg*

Electricity utility managers understand that the industry has rapidly moved from local monopolies to one that is customer-driven. Cogeneration and competition via open transmission policies have disrupted traditional pricing arrangements. Cost allocation manuals are becoming increasingly irrelevant as the electricity industry becomes more competitive. The purpose of this paper is to outline two approaches which enable the recovery of joint costs in a competitive environment. One approach involves utilizing Two-Part Pricing schemes, so the customers' share of joint costs is less dependent on total consumption. Such rate designs better reflect cost causation on the margin, while permitting recovery of some fixed costs. Another approach involves lower prices to those demanders with alternative sources of supply. Although higher prices to inelastic demanders -- those without options -- raises some tough political issues, those customers would be even worse off if business and other large customers abandoned their traditional suppliers. Thus, Ramsey Pricing (the technical term for this approach) involves price discrimination (or price differentiation, if the former term seems too value-loaded).

The municipal utility is going to have to generate value for customers by devising new rate designs which create win-win opportunities. Both Two-Part Pricing (using Historical Customer Baselines) and Ramsey Pricing represent innovative ways to recover joint costs. First, some background material needs to be reviewed.

1. Background: Recent Trends

The electric energy industry lags behind telecommunications in terms of competitive pressures, but regulatory roadblocks to competition at various stages of production are beginning to fall. Since most regulatory authority is vested in the states, the system is conducive to regulatory innovation. The process of evolution within the American regulatory environment is driven by wider adoption of approaches that have been successfully implemented in a few states. This heterogeneity also results in confusing and sometimes contradictory state regulatory regimes. For investor-owned utilities, rate of return (ROR) on rate base regulation has characterized the industry, with customer-class cost allocation rules, fuel adjustment clauses, and management audits further constraining prices and revenue requirements. For municipal utilities, cost allocations have tended to

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*The author is Executive Director, Public Utility Research Center, University of Florida. The views expressed here are those of the author; sponsoring organizations do not necessarily hold the views outlined in this study. The author is pleased to acknowledge conversations with Jeff Baxter and Tracy Lewis regarding many of the ideas presented here. However, errors of omission and commission are solely the author's responsibility.

establish revenue targets across customer classes, with prices reflecting some type of fully distributed cost.

The evolution of US regulatory policy illustrates changing attitudes towards the efficacy of competition in promoting efficiency. At the same time, concern over environmental impacts has placed new objectives onto the regulatory agenda; the new instruments for achieving new objectives raise complex issues. For example, state-mandated conservation programs will come under pressure, especially if retail wheeling is widely adopted. The costs of DSM programs cannot be spread across a set of captive customers: larger customers, especially, will face choices they are currently denied. Most industry observers expect vertical disintegration and partial deregulation to continue. The implications for municipals are mixed. Non-generating distribution systems are in a position to "shop around." Integrated suppliers are likely to face revenue erosion as competition becomes more widespread.

The interests of various constituencies are tough to reconcile. The National Association of Regulatory Utility Commissioners (NARUC) wants to preserve the flexibility of states so that state PSCs can craft policies which fit their unique circumstances. Groups benefiting from current state regulations want to retain "local" control--preserving their relative benefits.

The American Public Power Association (APPA) supports the agenda of municipally-owned utilities. The National Rural Electric Cooperative Association (NRECA) seeks retention of rules that assist rural electric utilities. At the national level, FERC oversees wholesale and transmission issues, while state PSC regulate facility additions and retail rates. The conflicting pressures and overlapping jurisdictions make coherent policy development very difficult.

One conclusion is clear, price signals are being given greater prominence, although policymakers (both regulators and municipal authorities) tend to avoid dramatic changes in rate design for fear of political repercussions. Historically, prices for different customer groups were set using cost allocation procedures. Revenue "requirements" were determined from top down--with minimal attention to incremental cost causation. Today, prices and incumbent investments in generating capacity are constrained by competitive alternatives--induced by regulatory promotion of cogeneration and independent power producers (IPPs). Thus, in non-core (industrial) markets, customers have alternatives in the form of self-generation or geographic re-location. When revenues from some customer groups fall short of "allocated" costs, utilities experience financial pressures. Core (residential) customers can flex their political muscle to avoid rate increases, resulting in realized returns becoming a residual. For IOUs, rates of return were never "guaranteed"; rather, they were "allowed". However, returns have become more problematic in a world where traditional entry restrictions are being set aside. These developments will constrain municipal utilities and REAs as well.

Deregulation and emerging competition will tend to promote least cost supply. Some vertically-integrated municipal suppliers have low incremental costs relative to their potential competitors. If they have high average (embedded) costs, they will come under financial pressure. It may be difficult to meet interest coverage or continue to transfer traditional amounts to city coffers. However, low incremental cost suppliers are still going to be able to compete for business. High incremental cost suppliers will be in trouble in a competitive environment. "Stranded investment" is just another word for generating capacity that cannot compete when electricity markets are opened up.

National regulatory policy has leaned in the direction of pro-competitive market structures at the generation level. Since PURPA's promotion of cogeneration via qualifying facilities (QFs) and of IPPs, national policy has continued to view wholesale competition as stimulating real savings for final demanders. Nonutilities supply almost ten percent of all electric power in the U.S., and between 1991 and 1994, they built over half of all new capacity. The Energy Act of 1992 created Exempt Wholesale Generators (EWGs) as another vehicle for introducing new players into the game. Since access to transmission can be mandated by FERC, terms and conditions of transmission access has become a significant regulatory issue. Ultimately, large buyers may gain access to alternative suppliers via the transmission network: retail markets will change dramatically. While the problems for network coordination, construction, and reliability are substantial, the trend seems irreversible.

In 1994, both California and Michigan established programs designed to promote more competition. Larger customers who have the ability to shop will tend to pay market-based (incremental cost) prices, leaving core (residential) customers at risk for covering the costs associated with higher cost capacity. The fear of so-called "stranded investment" blunts efforts to open up local markets.[1] The short run impacts of competition differ from the long run impacts. In the short run, the efficiency gains may not be substantial, given the

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[1]Reduced demand growth, nuclear plant cost overruns, environmental costs, and continued low natural gas prices has lead to excess and high cost capacity whose economic value is lower than book value. The resolution of the stranded investment problem has been linked by some to the terms and conditions of transmission access. There had been a "regulatory compact" under which capacity was built and changing the rules of the game is perceived as unfair. As Costello, Burns, and Hegazy (1994) note, vertically-integrated utilities, conservationists, and environmentalists tend to oppose retail wheeling. For the former, monopoly franchises are lost as competitors threaten to take away customers. The two latter groups fear reductions in (or elimination of) utility-funded Demand-Side Management (DSM) programs. Also, the forms of Integrated Resource Planning (IRP) which emphasize environmental costs above and beyond those addressed in national laws are threatened. Those supporting immediate retail wheeling argue that sunk costs ought to be ignored for policy purposes--leaving investors holding the bag. Large industrial and commercial customers do not want to bear transition costs.

demand elasticities--though the monetary transfers could be significant. Over the long run, the movement away from cost-based regulation for IOUs is likely to further stimulate cost-containment and improved price signals. Municipal utilities will not be insulated from these pressures.

PURPA-induced competition in the wholesale market for electricity has increased the importance of transmission access as utilities try to find the lowest cost suppliers whose generating facilities may be located far from the utilities' retail markets. The provision of EPAct (1992) requiring utilities to offer wheeling to third parties for a fee is possibly the biggest change in the industry in more than fifty years.

Continued regulatory and legislative debate can be expected on transmission access and pricing, bidding procedures, setting new price regulations, and devising alternative regulatory constraints. We can already see the outlines of changes that are altering the regulatory landscape. Some believe that competition has become an objective--rather than a mechanism for achieving economic objectives. Certainly, national legislation and FERC have promoted entry into generation markets as a way to keep energy costs down. With this thrust has come pressure for transmission access at a fair price.

2. Competitive Pricing and Efficient Investment[2]

If economists agree on one point, it is that competitive pressures drive price towards marginal cost. Both monopolists and competitive suppliers can utilize a wide range of rate designs. The following represents a partial listing of concepts that can help us understand pricing options.

• **Marginal cost pricing.** The allocative efficiency of having prices track incremental costs is well known. If marginal costs are low compared to average cost, complicated rate designs (such as multipart pricing) may be required for revenues to cover costs. Furthermore, short run and long run marginal costs will differ--so while the former serve as the standard for pricing decisions, the latter are determined by investment patterns since they reflect avoided costs from deferred capacity. Utilities will be devoting substantial resources to improving their understanding of their marginal costs.

• **Cross subsidization and rate design as taxation.** *Cross subsidization* can be a deliberate policy objective as some customers cover the incremental costs of serving favored customers. It can stem from inappropriate allocations of fixed or variable costs. Alternatively, differential burdens associated with bearing a large proportion of shared costs is often labelled as a "subsidy" for a customer group. Whichever definition of subsidy is

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[2]Parts of this section draw upon Berg and Tschirhart (1995), "Contributions of Neoclassical Economics to Public Utility Analysis," *Land Economics*, August, 71:3.

chosen, competition tends to limit the ability of utilities to tax some customers to benefit others. Entry will occur in markets with high markups above cost.

• **Discriminatory pricing and demand separation.** The ability to separate markets and prevent resale is facilitated by customers being hooked up to utility distribution systems. Since consumers with inelastic demanders are often the ones regulators are trying to protect from monopoly power, regulatory commissions often will overlay *cost allocation regulation* upon rate level regulation--preventing "undue" discrimination. However, price-cost margins generally differ across customer groups. Commercial customers have often faced the greatest markups. Competition will constrain such utility behavior in the future.

• **Ramsey Pricing.** If the firm can identify different customer groups and charge different prices to the various customer classes, it can utilize *Ramsey Pricing*. However, such a pricing policy (charging more to those with relatively inelastic demands) might still be viewed as unduly discriminatory, even though the supplier does not realize excess returns. Citizens might prefer other price configurations for electricity.[3]

• **Peak load pricing and daily demand patterns.** Almost two decades after the Electric Utility Rate Design Study[4], utilities are beginning to apply those lessons to their present competitive predicaments. Utilities realize that they have to design prices so that customers obtain substantial benefits -- otherwise competitors will lure customers away with better offers. From the standpoint of the supplier, marginal cost places a floor on the price. However, marginal cost depends on cost and demand conditions -- varying by time of day and season of the year. Therefore, *time-of-use pricing* represents an important tool in the rate designer's toolkit. *Real-time pricing* provides price signals that reflect current operating conditions (including prices available via power pools and long-term contracts). Utilities will find themselves playing the role of energy broker for large customers. If they do not take

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[3]Furthermore, there is no guarantee that Ramsey Prices are sustainable in the long run: some coalition of customers could end up paying more than the *stand-alone* costs of serving them -- leading to self production and the loss of their business. The technical literature on Ramsey Pricing is ably summarized in Sheshinski (1986) and Braeutigam (1989).

[4]The Electricity Utility Rate Design Study was co-sponsored by the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association for the National Association of Regulatory Utility Commissioners. Ninety-two studies on costing, rate design, demand elasticities, direct load control, and cost-benefit analysis emerged from that effort. The projects are summarized by Michele LaMorte, "Overview of Reports from the Electricity Utility Rate Design Study," in *Innovative Electric Rates* by Sanford Berg, Lexington Books, 1983, pp. 305-314. Also see J. Robert Malko and Philip R. Swensen, "Pricing and the Electric Utility Industry," in *Public Utility Regulation*, eds. K. Nowotny, D.B. Smith, and H. M. Trebing, Boston: Kluwer Academic Publishers, 1989, pp. 35-77.

on this task, competitors will take responsibility for meeting customer needs with electricity from least cost suppliers in the region. Rate design in such situations must take production technologies and demand interrelationships into account. Consumers value reliability of service which will be affected by the interaction of price (announced in advance) and uncertain demands (driven by weather, seasonal conditions, and hourly factors) and production capabilities (related to unplanned outages).[5]

• **Interruptible and Curtailable Rates.** Utilities have traditionally given large business customers price discounts if part of the load could be curtailed upon request or if nearly all the energy consumption could be interrupted with some advance notice. The lower prices were supposed to reflect the capacity savings associated with such customers. In reality, curtailments and interruptions seldom occur for many such customers, so one could argue that those reduced rates are based more on demand elasticity consideration than cost savings. Nevertheless, both rates will probably be modified in a competitive environment. Large customers will probably develop a portfolio of contracts, some will involve sales at a price, and others will reflect spot market conditions. Risk will be borne by those suppliers (and customers) willing to accept the uncertainty of price fluctuations.

• **Multipart pricing and patterns of customer demand.** The last concept reviewed here offers some promise to utilities who seek to have marginal price reflect marginal cost. These suppliers can recover capacity costs via a monthly fixed charge. Whether one is considering pricing entry and rides in an amusement park or access to and usage of a telephone system, multipart pricing offers a viable option for enhancing revenues. Much of the literature on multipart pricing and nonlinear outlay schedules is surveyed by Brown and Sibley (1986). The pattern of individual demands proves to be important for the development of rate designs involving monthly fixed fees and usage charges. The next section develops these ideas in greater detail.

3. Multipart Pricing and the Promotion of Efficiency

In the short run, with capacity costs fixed, changes in the wholesale pricing structure can involve particular customers or customer classes benefitting at the expense of others. Whether the process is a zero-sum game depends on the nature of rate re-structuring. If the savings obtained by winners is roughly equal to the additional outlays required of losers, then the objective of net revenue neutrality sows the seeds of conflict. For example, lowering the price to one group and raising it for another can have this characteristic. However, multipart pricing enables the supplier to create win-win options--bringing the marginal price down to incremental cost, while recovering current capacity costs via fixed monthly fees.

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[5]Crew and Kleindorfer (1986) have made a number of important contributions to this literature. See also Panzar (1976), Sherman (1984), Berg and Tschirhart (1988), and Burness and Patrick (1991).

It should be noted that cost allocations which are currently used may seem reasonable and consistent with industry practice. Nevertheless, these allocations often are quite arbitrary--reflecting some view of fairness rather than cost causation. Evidence from other industries suggests that competition will force marginal price towards incremental cost.

A diagrammatic representation may help explain the win-win aspects of multipart pricing. Figure 1 depicts a demand curve. At lower prices, the customer is willing to buy more electricity. At very high prices, customers will only apply electricity to very high valued uses. If price is quite low, then thermostats may be adjusted to give greater comfort, more electricity-intensive machinery might be utilized, and energy-conservation activity is less cost-effective from the standpoint of the buyer. In the short run, customers are not likely to be able to make substantial behavioral or operating adjustments, but the change in consumption will be greater as customers have more time to adapt to a permanent price change.

Utilities are used to thinking in terms of a customer's load shape and how this influences the system load. However, the load shape is a function of the price structure. Time-of-use pricing will alter the hourly pattern of electricity consumption -- with that pattern changing more dramatically as customers have more time to adjust to the new price structure. Responsiveness of customers is characterized by economists in terms of demand curves.

The *Law of a Downward Sloping Demand* has theoretical and empirical support. Utilities recognize that price influences consumption in the way described above. The Law's *Corollary of Greater Responsiveness with Longer Adjustment Time* has also been verified. The position of the demand curve is affected by other factors outside the utility's control. If the price of substitutes decreases, demand for electricity shifts in. If the prices of appliances that use electricity (complements) fall, then the demand for electricity shifts out. Weather conditions also affect the hourly load and monthly consumption. In the Figure, if price is $.08/kwh, then the customer depicted here consumes 1000 kwh. This could be broken down to hourly consumption, but this simple example illustrates the impact of a price reduction. If price falls to $.05/kwh, more than 1000 kwh would be demanded with a lower price. Note that if incomes rise, or average family size increases, or square feet per house increases, or temperatures are less moderate, the demand schedule will shift out. The hypothetical demand curve depicted in Figure 1 holds all these other factors constant, so that monthly consumption depends on price.

In this example, If price per kwh is $.08, then 1000 kwh are purchased, for a total consumer outlay of $80. If price were $.05, then 1300 kwh would be purchased, for a total outlay of $65. If demand had been more responsive to the price reduction (so that consumption rose to, say 2000 kwh, then total expenditures by this customer would have risen to $100. Thus, an increase in outlays does *not* necessarily imply a reduction in customer satisfaction. In this case, the price reduction induced additional consumption, and kwh were applied to valued uses by the customer!

In the case of the demand curve depicted in Figure 1, the price reduction from $.08 to $.05 yielded an improvement for the consumer. Analytically, this gain could be broken into two parts. The first part reflects the $.03 is saved on each of the 1000 units that used to be purchased at the higher price (area A = $30). Furthermore, 300 additional units are purchased when the price is only $.05. Economists identify area B as reflecting the benefits (above the outlays) associated with this additional consumption. Area B is $4.50 (the area of this triangle is half the base times the height).

Thus, the price reduction benefits the customer by $34.50. The $15 reduction in outlays (from $80 to $65) is *not* a good indicator of the consumer benefits associated with the price reduction. This point is very important, because rate design that focuses on outlays rather than customer satisfaction is likely to miss some win-win opportunities. In a competitive environment, suppliers cannot afford to ignore opportunities.

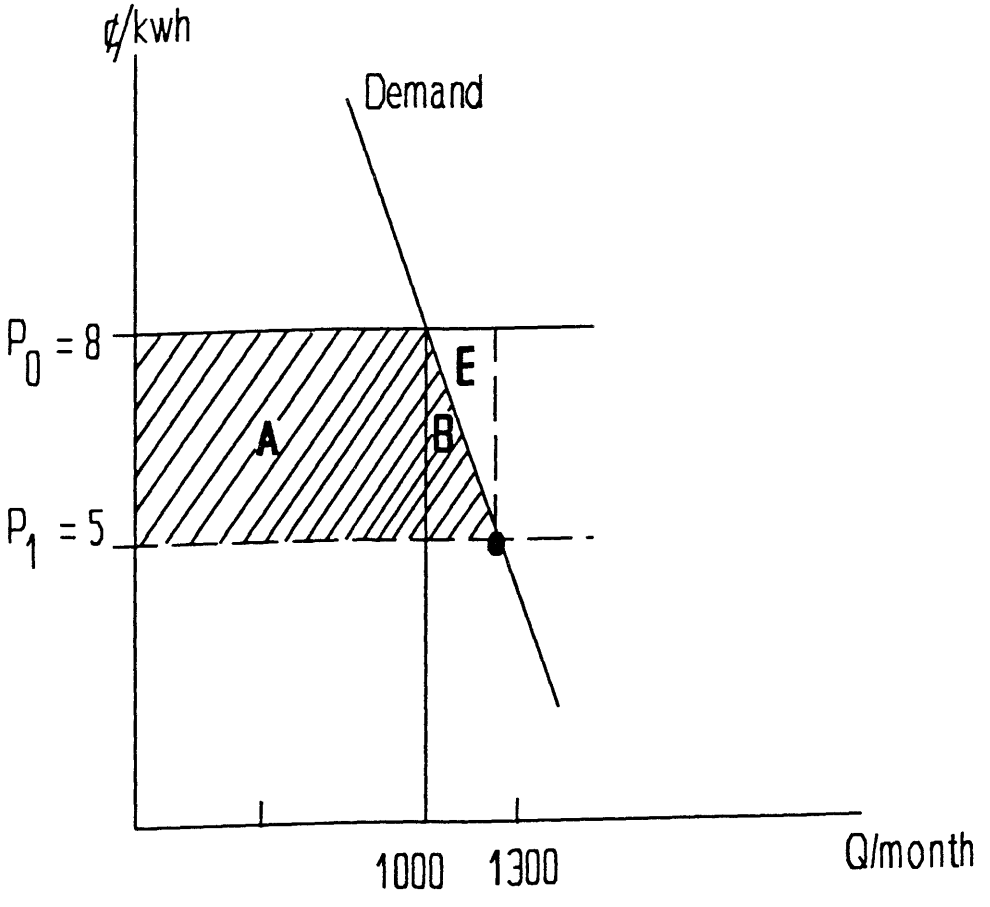
So far, we have not considered the firm. If its incremental costs were $.08, then a price reduction to $.05 is a losing proposition. The cost of serving the customer is $104 ($.08/kwh times 1300 kwh), but the revenue from the customer is only $65 ($.05/kwh times 1300 kwh). Underpricing electricity relative to its cost hurts the supplier more than it benefits the customer! From the diagram, the customer gains A+B, while the firm loses A+B+E. If, during peak periods, the price is below incremental costs, the utility ought to revise its prices (if the metering costs are not small relative to the savings).

In the case of the price reduction, what if the incremental cost were $.05? The $.08 price was high relative to the cost of additional kwh. Now the customer gains (A+B), which is more than the supplier loses (-B) from the price reduction! This observation suggests that a win-win option is possible. The utility could offer the customer a multipart price instead of the uniform price of $.08/kwh. The rate structure could be a $30 monthly fee (regardless of units consumed) and a per unit price of $.05. Since area A is $30, it is clear that the customer is better off by area B ($4.50) under this alternative rate design. And the firm is no worse off. So long as the monthly fee is less than $34.50 (and per unit price is $.05) , the customer is better off under the multipart scheme than paying a uniform per unit price of $.08.

Return to the $30 fee case, where total customer outlays now equal $95 and incremental cost is $.05. If the total bill is divided by the 1300 kwh, the average price is about $.073. Why not just set a price of $.073 and avoid the slightly more complicated pricing scheme? After all, customers look at their total bills. The response to this question is that the combined gains to the customer and the supplier would be less if price were only lowered from $.08 to $.073 than if the $30.00 monthly fee were imposed in conjunction with $.05/kwh. By himself, the customer is better off by more than $7.00 with the $.007/kwh price reduction. That per unit saving times 1000 kwh happens to be greater than area B. But all of that gain is essentially balanced by a net revenue loss experienced by the supplier! That price reduction is not a win-win outcome. The multipart scheme keeps the supplier whole, while making the customer $4.50 better off than before. Furthermore, the price of

Figure 1

Benefits from a Price Change



$.073/kwh is inefficient. It discourages consumption that is worth more than the resources that would have gone into the production of additional kwh (ie., the price of $.073 is greater than incremental cost, $.05).

We saw that setting the marginal price equal to incremental cost increased consumption to 1300 kwh. The customer valued that additional consumption more than society valued the resources that went into creating the additional kwh. Thus, incremental cost pricing promotes the efficient use of society's resources. If price is above incremental cost (as is the case with much off-peak consumption), we are underconsuming electricity. If price is below incremental cost (as can be the case with on-peak consumption), we overconsume electricity. Multipart pricing combined with peak load pricing can make both the firm and the customer better off. Peak load pricing by itself may benefit customers and/or the supplier.

Figure 2 illustrates the problem of pricing below incremental cost. Each unit sold is priced at less than the cost of production. The supplier would be better off making a deal in which he gave the demander a lump sum credit to his bill of X+Y, while raising the price to P_1. The customer is no worse off than initially (less electricity is consumed, but the customer is indifferent to P_0 for each kwh versus a rebate of X+Y per month and a higher price of P_1.

Note, these observations regarding multipart pricing are strengthened when longer run adjustments are taken into account. Demand is more elastic (or responsive to price changes) when customers have more time to adjust their energy-using equipment. If price increases, the firm may have few alternatives in the short run. But soon, energy-conserving investments can be implemented, and consumption drops more dramatically than in the initial months. The time for adjustment depends on the nature of the industrial, residential, or commercial demand. Utility managers who understand the role of price signals can promote the efficient conservation of energy.

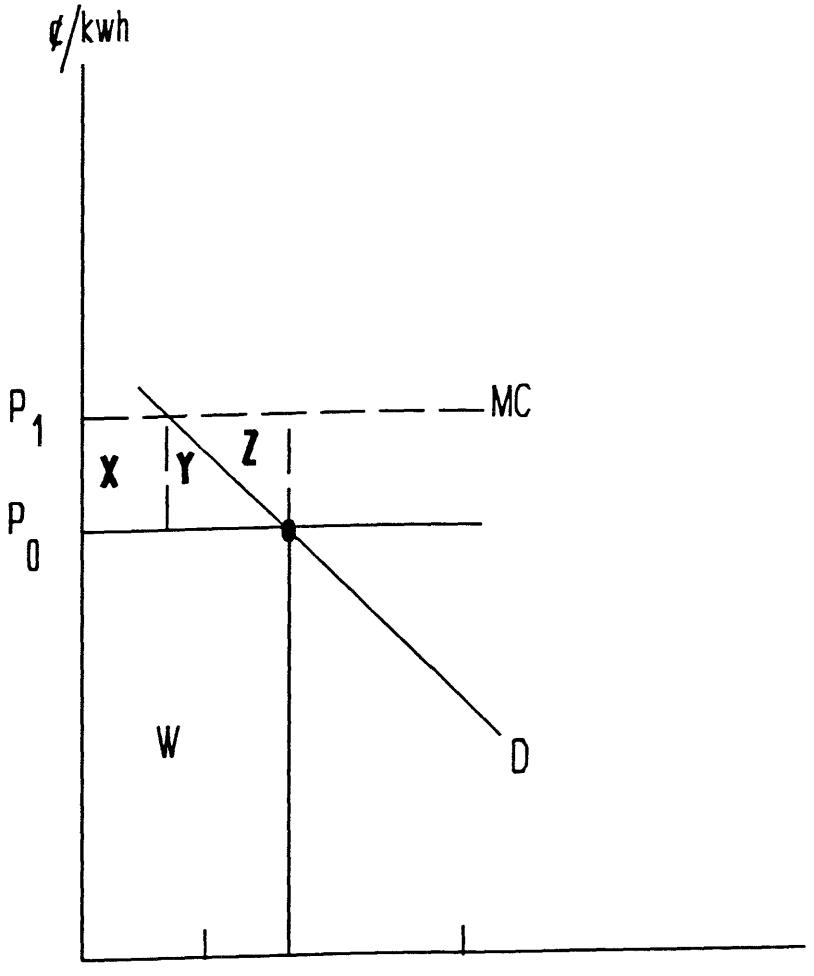
The precise amount to be included in the fixed fee is not a simple calculation. Were recent years "normal"? What if the level of this historical contribution is no longer sustainable in a competitive market? The answers to these questions require substantial analysis. Suffice it to note that such monthly fees can be calculated that would leave the firm better off than before. Bringing the incremental price in line with incremental cost is a potential win-win move. Rate designers ought to consider this addition to their price portfolios in a competitive era.

4. Ramsey Pricing

As noted earlier, Ramsey Pricing corresponds to price discrimination such that total revenues equal total costs. The ability to separate markets and prevent resale is facilitated by customers being hooked up to utility distribution systems. Since consumers with inelastic demands are often those regulators or municipally-owned utilities are trying to protect, firms

Figure 2

Pricing Below Incremental Cost



often overlay cost allocation procedures onto price level decisions--limiting "undue discrimination."

Ramsey Pricing is related to marginal-cost pricing in that prices are a percentage deviation from marginal costs, where the percentage is inversely proportional to demand elasticities: more elastic (responsive) demands have lower price-cost margins.[6] In Figure 3, two demands are illustrated. If price is $.04 in each market, then the total contribution towards fixed costs is E+F ($20 in market 1) and T+V ($20 in market 2). So the base case involves 1000 kwh monthly consumption in each market, with $40 in revenue above incremental cost going towards fixed costs. If price is increased to $.06 in the relatively inelastic market 1, the firm gains A ($18) and loses F ($2), for a supplier gain of $16 in this market. Although the firm no longer receives revenues of F + G ($4) due to the 100 kwh reduction in quantity consumed, the supplier also avoided the cost (G) of producing that output. Thus, the loss of F is recorded. The customer is worse off: given by -(A+B), or $19. The numbers indicate that societal welfare has declined by $3, as price has been increased far above incremental cost (($.02). However, if the price is reduced to $.025 in market 2, then this customer gains more than the utility loses, and the potential for an overall welfare improvement exists.

On net, the reconfiguration of prices can improve societal welfare so long as gains (and losses) experienced by either customer are valued equally. To see this, consider Market 2 in greater detail, where price is reduced from $.04 to $.025, and consumption increases from 1000 kwh to 1600 kwh. The supplier loses T ($15) but gains W ($3) when it reduces price to $.025. There is a supplier loss of $12 in market 2. However, customer 2 gains T and U, where U is $4.50. Clearly, the customer gains (T+U equals $19.50) are

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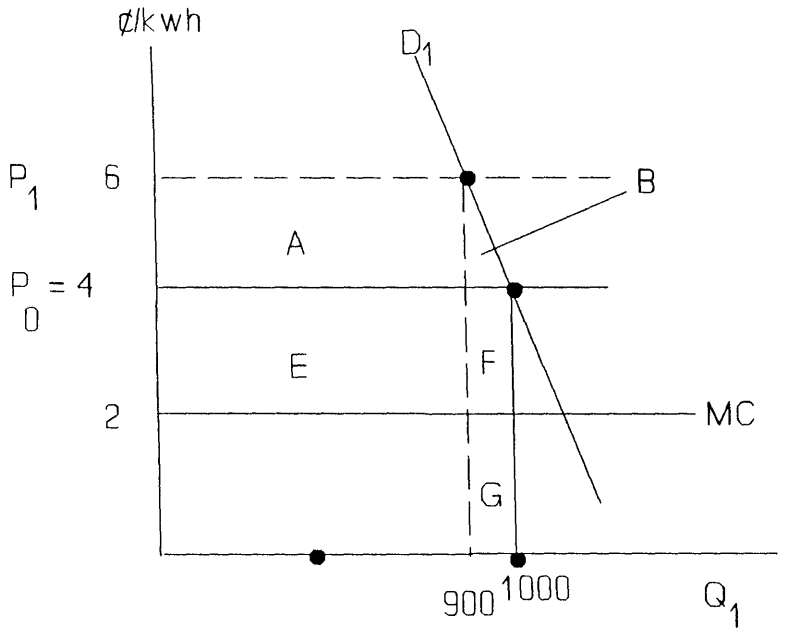
[6]Faulhaber and Baumol (1988, p. 594) cite Ramsey Pricing as "...a clear example of a principle that derives from the [economic] literature and has (recently) achieved a good deal of attention among government agencies." They note that it has been discussed in many courts, state commissions, the Federal Communications Commission (FCC), the Federal Energy Regulatory Commission (FERC) and the Interstate Commerce Commission (ICC), as well as in other countries. Faulhaber and Baumol also highlighted the stand-alone cost test as an example of a contribution of economic theory to regulatory pricing practices. The test places a ceiling on rates. No consumer or group of consumers ought pay more for service than the cost of serving them apart from all other consumers. Although this approach can be traced to pricing practices established for the Tennessee Valley Authority under the name "separable costs and remaining benefits" (EPA, 1975, Straffin and Heaney, 1981), only in the last two decades has it become prominent in the literature where it has been related to the core concept in game theory (Faulhaber, 1975; Sorenson, et al., 1976, Sharkey, 1982). The theory also provides regulators with a rigorous definition of cross subsidization that eschews the arbitrary definitions associated with fully distributed cost pricing practices. Faulhaber and Baumol indicate that both the FCC and ICC have considered using stand-alone cost tests in rate making.

Figure 3
Uniform vs. Ramsey Pricing

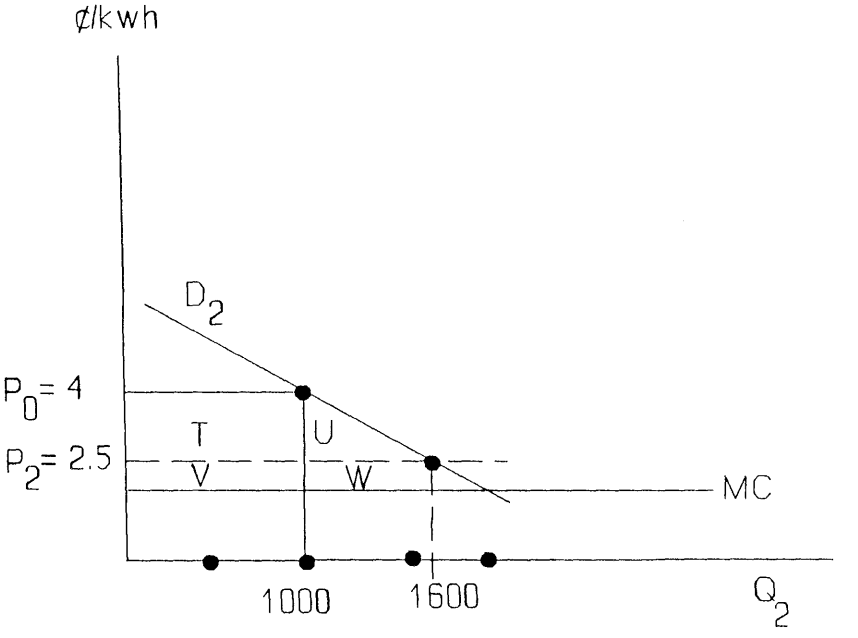
(1)



Price Increase
Supplier: +A - F
+$18 - $2

Customer: -A - B
-$18 - $1

(2)



Price Decrease
Supplier: -T + W
-$15 + $3

Customer: +T + U
+$15 + $4.50

more than the supplier's losses. The common sense explanation is that bringing price closer to incremental cost increases economic efficiency in this market (here, by $7.50). When the two markets are taken into account together, the supplier is actually better off (+ $18 - $12) while customer welfare (weighted equally for winners and losers) has also increased (down $19 in market 1 and up $19.50 in market 2).

This example is meant to illustrate the power of pricing closer to incremental cost in elastic markets--balancing off the inefficiencies of raising price further above incremental cost in another market. The formula for calculating optimal markups in the two markets involves markups that are inversely proportional to the respective demand elasticities.[7]

Electric utilities have charged different prices to different customers for decades. Ramsey Pricing involves charging more to those with relatively inelastic demands. Commercial customers often do not have cogeneration opportunities and are often the ones hit with the highest prices relative to incremental cost of service. Residential customers have political clout, so that despite relatively inelastic demands, their price-cost margins are often smaller than for other customer groups. Industrial customers, on the other hand, may be footloose in the long run: firms can move production capacity to other locations. Alternatively, industrial customers may have self-production as an option. In either case, these customers have relatively more elastic demands. Electric utilities have responded to such situations by offering lower prices (via "cooked" cost allocations) or interruptible rates at discounts that might be greater than the amount warranted by the actual interruptions.

Competition is likely to attack those customer classes with greatest price-cost margins. Thus, commercial accounts would appear to be vulnerable to entrants who have access to transmission and distribution facilities. Municipal utilities will have to respond to such threats by re-structuring their rate designs. The presence of alternatives makes customer demands more elastic. So utilities will act in such a way as to reduce the prices quoted to such customers. From the standpoint of social efficiency, this restructuring is appropriate if the market demand of such customers is relatively elastic.[8]

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[7]See Stephen J. Brown and David S. Sibley, *The Theory of Public Utility Pricing* (Cambridge University Press) 1986, for a thorough discussion of Ramsey pricing.

[8]If the customer's market demand for electricity is actually relatively inelastic -- but it becomes elastic with the availability of competitive options, then the reduction of such prices may not promote social efficiency. However, from the standpoint of public policy, this possibility is probably swamped by the view that competitive pressures will be more effective in promoting cost containment than regulation or municipal restraints. In terms of economic theory, the social efficiency losses (and gains) associated with welfare triangles are dominated by the large rectangles reflecting cost savings associated with improved incentives for cost containment. Public policy has supported increased competition in generation not just because of the associated rate restructuring (such that prices track costs), but also because costs are likely to be lower with competitive pressures.

5. Concluding Observations

What are the implications of competitive trends for municipal utility pricing?

(1) **Utilities that understand their cost structure and are successful at cost containment will be a better position to develop prices that enable them to survive in a competitive world.**

(2) **Utilities that understand their customers' actual (and potential) consumption patterns have an advantage over potential rivals.**

(3) **Market intelligence will become a major factor in decision-making. Major customers will be lost and gained on the basis of the types of contracts that are developed.**

(4) **New skills will be required of utilities. During the transition to competition, utilities must restructure themselves to provide the information and incentives to compete effectively with their rivals.**

These points need to be underscored. If the supplier does not know its own incremental cost, it cannot be sure whether additional sales are financially desirable. Similarly, if the supplier does not know how the customer is likely to respond to new prices, financial planning and capacity decisions become problematic. Potential load shapes become relevant for decision-makers, since new rate designs will induce changes in consumption patterns. If simplicity is one casualty of competitive pressures, utility account managers will have to explain the benefits of more complicated rate structures to their customers. Competition will make life harder for utility managers.

Monopoly suppliers are able to dictate price. So long as total revenues cover total costs, there may not be pressure to identify incremental costs. Some customers may be paying far more than cost of service while others could be paying less that incremental cost. However, the prices, based on (politically acceptable) cost allocations are not necessarily sustainable under competition--where price tends to track the incremental cost of electricity. Cost allocations which were unrelated to cost causation were possible in the absence of customer choice. But the world of electric utility monopolies is rapidly disappearing.

New price structures can offer win-win opportunities, such that both the supplier and customers can be better off than before. Of course, if competition drives the average price too low relative to the utility's average cost, most of the benefits from rate re-design will be captured by customers--if the utility is to successfully retain its customers. The principles of rate design identified here are crucial to the recovery of joint costs in a competitive environment.

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