New Regulatory and Management Strategies in a Changing Market Environment

Edited by
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Preface

The papers contained in this collection were originally presented at the Institute of Public Utilities Eighteenth Annual Conference, which was held in Williamsburg, Virginia, on December 8–10, 1986. This collection contains both the papers and the discussants’ comments.

We want to take this opportunity to acknowledge the suggestions made by the members of the Institute’s Advisory Committee regarding topics and speakers for the program. We also want to thank Mrs. Virginia Michels, who accepted responsibility for collecting the papers and overseeing the publication process.

The Institute of Public Utilities at Michigan State University is the oldest university-affiliated center for the study of public utility problems. It has established a reputation for objectivity and balance in all of its programs and publications. We trust that the reader will find the present collection maintains this tradition.

Harry M. Trebing
Patrick C. Mann
Part One

Transforming Regulatory and Management Strategies
Options for Modifying Rate Base Regulation

Robert J. Keegan and Paul F. Levy

The challenges currently facing state and federal utility regulators are substantial, for we are in a period when major structural changes are occurring in the electric, gas, and telecommunications industries. Competitive alternatives available to end-users are developing to varying degrees in each of these industries, and, as a result, many observers are questioning the appropriateness of continuing to apply traditional regulatory approaches. The call for reform is growing, and the movement seems to be in the direction of deregulation.

In the face of emerging competition, there is a strong tendency to draw generic conclusions about how the regulatory process should be altered. An examination of the various models for modifying ratebase regulation being proposed in each of these industries reveals striking similarities. In evaluating the merits of these proposals, it is important to resist the tendency to draw the conclusion that there is a single approach or modification to the regulatory process which is appropriate whenever competition appears to be penetrating a regulated industry. Competition
# Options for Modifying Rate Base Regulation

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Figure 1. Functional Segments in the Public Utility Industry

is developing in different segments of these industries to varying degrees, and it is important to examine the forces which are giving rise to competition in the various segments of each industry to see whether movement in the direction of deregulation is appropriate.

This paper, therefore, will cover two major topics. First, we will identify the functional segments in each industry and examine the degree to which and why competitive alternatives for end-users have developed in those functional segments; second, we will look at the various proposals being suggested for modifying ratebase regulation and evaluate those proposals on the basis of the competitive attributes being exhibited in each industry segment.

**Competition in Industry Segments**

**Background**

In the electric, gas, and telecommunications fields there are relatively comparable functional segments which can be broken down along the lines of production, transmission, distribution, and total product categories (see Figure 1).

Early in the development of the electric, natural gas, and telecommunications industries, it was recognized that certain fac-
simply establish a market price which reflects the cost of providing a particular commodity. The costs toward which competitive market forces tend to drive prices are not those of a particular firm, but rather, over time, they are the lowest level of costs incurred in producing and distributing the product which meets consumers' needs in the most efficient manner possible. In other words, competition drives an industry toward optimality; that is, the least-cost method of meeting a specific level of consumer needs. The farther an industry strays from optimality, the more susceptible that industry is to a loss of market share to substitute products provided by other industries. Similarly, the farther an individual firm strays from optimality in a competitive market, the greater will be its erosion of earnings as competition drives the market price toward a level which better reflects optimal costs.

A free market governed by competitive forces is a ruthless judge of performance because it does not allocate economic rewards and penalties on the basis of good intentions. A firm which efficiently produces a product can become suboptimal because of circumstances solely external to it, such as the development of a less costly substitute product or a major increase in one of its production input factors, which deprives it of the ability to be competitive. The marketplace will penalize all firms equally, to the degree that they become suboptimal, regardless of the reasons for that occurrence. Competitive markets, therefore, are forced to move toward optimality and, thus, accomplish the same objectives that regulation attempts to achieve: providing the least-cost means of meeting consumers' needs.

The cost-accounting principles used to establish rates for utility services under ratebase regulation, however, generally fail to incorporate the underlying forces of efficiency inherent in competitive markets. No matter how far a utility's costs stray from optimal levels, strict adherence to cost-of-service principles will result in prices that reflect whatever level of inefficiency is inherent in the firm's accounting costs. This aspect of cost-of-service regulation is not readily apparent and does not have significant consequences so long as an industry continues to display the natural monopoly characteristics of scale economies and entry barriers, and so long as other industries do not develop substitute products which have a significant cost advantage over the services provided by the utility.

If these conditions are not met, however—if the economies of scale in an industry begin to erode or for one reason or another are not achieved, or if substitutes gain a significant price advantage—then competition will affect a regulated industry in a way which will expose both the deficiencies of regulation and any suboptimal conditions which may exist. Exactly this phenomenon has occurred and is currently occurring in regulated markets. Competitive alternatives are developing in the segments of these industries where there has been a significant change in the cost of providing a particular functional service or its equivalent.

In evaluating the implications of emerging competition, it is first necessary to identify the functional segment of the industry being penetrated by competition and determine whether that competition is developing because natural monopoly characteristics are disappearing or because some other factor has deprived the monopoly of the ability to be the least-cost provider of consumer needs. If competition is developing because of the erosion of natural monopoly characteristics, a movement toward deregulation would clearly be in order. If competition is emerging because monopoly prices have only temporarily become suboptimal, natural monopoly characteristics could well restore the company's monopoly power, and the regulatory imperative would continue to exist. It is, therefore, necessary to look in more detail at the cost changes occurring in each industry and analyze more fully the industry segments experiencing competition and the nature of the factors underlying its development.

**Competition in the Electric Industry**

In the production or generation portion of the electric industry, end-users have limited competitive alternatives. This segment of the industry has, however, undergone significant changes in its cost structure in recent years. Escalating costs for constructing large central generating stations, combined with reductions in fossil fuel costs, have undermined the strategy of substituting capital for fuel and deprived many utilities of their traditional role of being the least-cost provider of electric service. This situation has provided incentives for competitors, in the form of lower cost generators and other nonutility generation providers, to enter the market. End-users, however, have essentially been precluded from taking advantage of these competitive alternatives because ac-
cess to transmission and distribution facilities has not been made widely available. Competition in the generation segment of the electric industry has, therefore, been limited to self-generation and sales for resale to electric utilities. Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA) was designed to overcome some of these obstacles, thus enabling these alternative sources to be developed. Their power will not necessarily be for sale to end-users, but rather for sale to electric utilities in the wholesale or resale market.

In the transmission and distribution segments of the industry, costs have not undergone a significant change, and these sectors continue to display natural monopoly characteristics. As a result, the barriers to entering these markets and providing these functional services remain substantial, and there is no competition except to the degree that self-generation makes the need for such services unnecessary.

With regard to the total product delivered by electric utilities, competition remains extremely limited. For certain electric end-use applications, such as heating and cooking, there is competition from substitute fuels in those instances where the increased capital costs of the end-use appliance are outweighed by the cost differential of the underlying fuel source. Also, in the large-volume industrial end-use market there is competition from self-generation projects, and in some sections of the country, where there are excess generating capacity and significant rate disparities between electric utilities, and where wheeling has been made available, there is some interutility competition.

In the lower volume residential and commercial markets, however, the availability of these competitive total product alternatives is much more limited, and there are few substitutes currently available for the majority of electric end-use applications.

**Competition in the Gas Industry**

The functional segments of the gas industry are production at the wellhead, transmission by interstate pipelines, distribution by local distribution companies, and the total product.

With the deregulation of wellhead gas prices and the emergence of a spot market, there is increasing competition among end-users for gas supplies. Similar to the electric industry, however, this competition is limited by bottleneck pipeline transmis-
is competition in this segment for high volume users in terms of shared tenant services and resale, there is unlikely to be much competition for the vast majority of basic exchange customers for access services. Since telecommunications is in many ways a multi-service product, there is some competition developing in the area of enhancements to the access services provided by local operating companies. That takes the form of vendors marketing customer premises equipment which performs services that could otherwise be built into the local network and provided as a component of access. But, overall, competition for providing access services is limited, and these facilities represent a bottleneck which has the potential to limit an end-user’s access to transport services.

In the total product segment there is competition to provide high volume users with end-to-end telecommunications services. For some of them it is both technologically feasible and, because of the current level of access charges, economic to provide them with access services which bypass local operating company facilities. Competitive alternatives for most other customers needing access services, however, will continue to be unavailable, thus making them captives of the local operating companies. These will continue to retain significant monopoly power in the provision of access services.

In order to ensure that local loop and local switching facilities, the bottleneck component of the network, were no longer used to stifle competition in the transport segment of the industry, AT&T was required to divest itself of the local operating companies. These are now required to provide competing transport carriers with equal access to their facilities. Likewise, open network architecture requirements have been proposed as preconditions to local operating company diversification to ensure that competition in the provision of network enhancements will be promoted. In addition, the local operating companies were precluded by the Modified Final Judgment from providing interstate and intrALATA services so that they would not have the incentive to use their bottleneck facilities in a manner which would competitively disadvantage other long distance service providers.

Common Attributes among Regulated Industries

This analysis of emerging competition in the electric, gas, and telecommunications industries reveals that they have several attributes in common. Competition in the production segment of each of these industries is now possible and has begun to emerge to varying degrees. Bottleneck facilities in the respective transmission and distribution segments have the potential to limit seriously the access of end-users to alternatives competing in the production segment of each industry. In addition, bottleneck facilities also provide their utility owners with monopsony power and limit the ability of competing suppliers to get their products and services to end-users. In the total product segment of each industry there is competition in the form of either substitute products or bypass facilities constructed by or for large users. Smaller end-users, both commercial and residential, tend to be captive customers of the utility owning the bottleneck facilities because of economic limitations imposed by the capital costs associated with either obtaining equipment which will utilize substitute products or the cost of building bypass facilities.

In looking at each of these industries, it is the type and amount of competition as well as how that competition is divided between the production and total product segments that determine the degree to which structural and institutional changes are being implemented in these industries.

In electricity, where competition in the total product segment remains very limited, regulatory reform has been restricted to overcoming the monopoly provider’s monopsony power by requiring, through PURPA legislation, that utilities purchase supplies from alternative producers of electric generation. The fact that competition in the total product segment has been limited by the lack of substitutes for many electric applications has meant that sales by electric utilities have not declined; indeed, demand continues to grow. The call for reform, therefore, has focused more on clarifying utility cost recovery rules under regulation than on fundamental structural changes disaggregating the functional services provided by electric utilities.

To a large degree, this is because electric utilities are concerned
primarily with the rules applied by regulators for recovering their investments, as opposed to being concerned over the market implications of any uneconomic investments they may have made. Declining sales and revenues as well as loss of market share are not serious concerns of most electric companies because they view most of their customers as being captive. This view follows from the lack of substitutes and the utilities’ control over the bottleneck transmission and distribution facilities, which preclude most forms of competition in the end-use market and provide electric utilities with a highly captive customer base. Therefore, electric utilities have not been deterred from seeking price increases designed to recover investments which have proven to be uneconomic when compared to alternatives.

To the extent that electric utilities follow least-cost planning strategies so that the generation component of their service remains below the cost of other potential generation options, there will be less demand for increased access to these competitive alternatives by end-users and a reduced call for modifications to rate-base regulation in this industry. To a large degree, the success of electric utilities in this regard will depend on whether economies of scale can be achieved in the construction of large base-load generating stations, where capital costs will continue to pose significant barriers to entry.

If, however, the disparity in the cost of electric generation provided by regulated utilities remains comparable or increases in relation to what is available from nonutility providers, then the call for increased competition within the industry by opening access to the transmission grid and local distribution network will grow substantially. This will occur if economies of scale can no longer be achieved in large generating facilities because smaller units will not impose the same barriers to entry and more vendors will be attracted to this segment of the industry. In such a situation, we will see greater pressure for vertical disintegration, disaggregation of services, and unbundling of rates in the electric industry, of a type similar to that being seen at present in the gas and telecommunications industries.

In gas, several factors have led to a significant increase in competition in the total product segment. The improved competitive position of oil as a substitute for natural gas has eroded the market share which gas companies had developed. Sales to end-users have declined, principally in the industrial market, and costs must be reduced if gas companies are to stop the erosion of sales and revenues.

In a cost-cutting effort designed to meet the competition from oil, interstate pipelines have attempted to reduce their weighted average cost of gas by rejecting supplies from producers whose contracts contain unmarketably high prices. This has caused contractual take-or-pay liabilities for pipelines to grow. These liabilities would have been transferred automatically to local distribution companies and their customers had the FERC not issued Order 380, relieving local distribution companies of the variable cost component of their minimum bill obligations under their contracts with the interstate pipelines. That action on the part of the FERC has placed extraordinary pressure on pipelines and producers to renegotiate existing high-price gas contracts. To the extent that payments are made by pipelines to buy out of these contracts, the FERC will determine the portion of these costs to be included in rates to local distribution companies.

The factor that distinguishes conditions in the gas industry from those in the electric industry is the emergence of a competitively priced substitute, resulting in decreasing gas sales and a growing inventory of supplies. Price is slow to react to this imbalance between supply and demand because of institutional barriers associated with existing long-term pipeline producer contracts and traditional regulatory practices. The market will not support contract prices that have become uneconomic in the face of falling oil prices, and therefore greater pressure has developed in this industry than in the electric industry to provide both producers and users greater access to bottleneck pipeline and distribution facilities. The FERC has responded with its voluntary open access transportation policy contained in Order 436.

As the gas industry continues to undergo further structural changes designed to allow gas to compete more directly in the end-use market, several factors must be closely monitored to assess the implications and feasibility of substituting competitive market forces for regulation. Do there continue to be economies of scale and barriers to entry in terms of gathering and aggregating gas supplies which give pipeline companies a natural monopoly advantage over competing gas brokers? If natural monopoly characteristics continue to pervade the supply aggregation component
of the business, then the ability to develop spot and futures markets which will satisfactorily compete with pipelines in the merchandising of reliable gas supplies is in question.

In addition, it must be recognized that a large number of smaller gas users remain captive customers of local distribution companies, within the context of their investment in their gas-burning appliances. As all sectors of the gas industry attempt to compete with oil for a larger share of the industrial use market, there will be a growing movement toward market segmentation and price discrimination. Producers, pipelines, and distribution companies will have a powerful incentive to reduce prices to customers with alternatives and shift costs to those customers who remain captive.

In telecommunications, technological developments appear to have eroded natural monopoly characteristics in the transport segment of the industry. Alternative providers of transport services are both building facilities and reselling services offered by what was previously the monopoly provider, AT&T. It is interesting to note that what has always been the most vertically integrated, regulated industry, with monopoly control from the manufacturing of network facilities all the way down to the manufacturing of customer premises equipment, is experiencing the greatest levels of competition in all functional segments and is also seeing the greatest level of vertical disintegration.

With the appearance of competition in segments of the telecommunications industry, it has become the national policy to promote that competition through regulatory forbearance, and, where bottleneck facilities exist at the local operating company level, to provide for equal access to those facilities. The important question which remains unanswered as we move aggressively in this direction is whether technology has indeed overcome the natural monopoly characteristics long believed to exist in the telephone network, or whether competition is developing rapidly in the transport segment of the industry because that service has historically been priced well above cost in order to obtain the subsidies needed to achieve the goal of universal service. If there continue to be economies of both scale and scope in the transport and switching segment of the industry, then competition is likely to develop only to a limited degree during a transition period when AT&T's prices for these services are altered to better reflect incremental costs. Following that transition period, AT&T could well emerge again as the monopoly provider of those services.

In each of these industries, therefore, it is the emergence of competition in the production segment, combined with competitive pressures in end-use markets, which has provided the impetus for structural changes. The institutional response has been to encourage and promote competition in the production segment through vertical disintegration, disaggregation of services, and unbundling of rates. These measures have been implemented to the greatest degree in those industries where it is believed that a viable competitive market can be sustained for services provided in the production segment. In each of these industries, however, the question of whether competition has developed because of pricing anomalies for production services or because of the erosion of natural monopoly characteristics remains unanswered. As we continue to promote such competition and to determine whether competitive market forces can be relied on in place of economic regulation of production services, we are confronted with the question of how to modify ratebase regulation in a manner which properly recognizes and reflects the existence and potential growth of that competition and the institutional changes which have been implemented to respond to it. The appropriateness of regulatory modifications is likely to vary depending on whether, and the degree to which, end-users are able to compete directly with utilities for production services, or whether the vast majority of end-users will have to continue to rely on the utility to procure services from competing suppliers of production services.

While we evaluate the viability of competitive forces in the production segments of these industries, utilities will continue to provide services both to end-users who have competitive alternatives and to end-users who will remain captive to the services of the utility. Many of the modifications to ratebase regulation being advocated are designed to respond to the increasing competition in end-use markets. The more of that a utility faces, the greater its need for flexible, market-responsive prices to meet that competition. In addition, the more competition a utility faces in end-use markets, the greater its potential for loss of market share and for erosion of sales and earnings. The degree of that competition determines the degree to which modifications to ratebase regulation appear to be required. Such modifications are needed to provide
for market-responsive prices, to preclude the cross-subsidization of a utility's competitive activities, and to protect captive customers from the burden of paying for that portion of a utility's fixed costs previously supported by customers who have turned to competitive alternatives.

It is, therefore, in the context of the structural changes implemented in response to competition in the production segment of each of these industries, as well as the level of competition being experienced in end-use markets, that we must evaluate and consider the implications and appropriateness of the various proposals being suggested for modifying ratebase regulation.

The Alternatives for Modifying Ratebase Regulation

The four most common alternatives proposed for modifying ratebase regulation are: (1) the contribution model; (2) the social contract model; (3) the surrogate market price model; and (4) total deregulation.

The Contribution Model

What we will refer to as the contribution model represents only a minor departure from the traditional concepts of ratebase regulation. Ordinarily, if a utility's sales for one reason or another begin to erode, then the fixed costs of the system are collected through higher prices for either a reduced number of unit sales or to a reduced number of customers. The contribution approach to regulation recognizes the need for market-responsive prices in those markets where customers have competitive alternatives, either in the form of substitute products or in the ability to obtain services through the bypass of local utility facilities. This method enables a utility to adjust its prices to customers with competitive options, provided that the prices charged would at least cover the utility's short-run marginal costs. To the extent: these prices produce revenues which exceed those costs, the revenues make a contribution to the embedded fixed costs of the business.

This approach considers captive customers to be the ultimate guarantors of the utility's embedded revenue requirement. The difficulty with this model is that, to the extent the utility is unable to retain market share for customers with competitive alternatives, responsibility for fixed costs incurred to serve those customers (including any new investments designed to enable the company to compete in those markets) would be shifted to the captive customers. Thus, they bear the risks associated with competition in other markets. Also, to the extent that flexible, competitive prices fail to reflect both long- and short-run marginal costs, there will be a cross-subsidization of a company's competitive activities.

The difficulty is that, under ratebase regulation, captive customers also bear the burden of increased prices which result from an erosion of sales or customers. Segmenting competitive from captive customers and engaging in discriminatory pricing to keep competitive customers on the system for whatever contribution to fixed costs can be exacted from them have a superficial appeal. What this indicates, however, is the difficulty of continuing to apply ratebase regulation when utility services are faced with competition in end-use markets. While the contribution model of price discrimination for competitive customers appears to offer some relief from this problem, it does not overcome the significant difficulties associated with cross-subsidization of competitive services or the burden of ultimately placing all fixed costs on a declining number of captive customers. In addition, the contribution approach fails to take advantage of emerging competitive market forces to promote economic efficiency in an industry.

The Social Contract Model

The second alternative to ratebase regulation involves what is referred to as the social contract. This model is being considered and implemented in the telecommunications industry in a number of states, particularly Vermont and Nebraska, and its applicability to the electric industry is referred to in this volume by Jo Ellen Murphy. Essentially this model identifies the company's captive customers and fixes their prices for a period of years, subject to an agreed-upon escalation index. Prices for all other customers are considered to be offered in a competitive environment and therefore detariffied and deregulated. The appropriateness of the model must, of course, be evaluated in the context of the underlying cost characteristics of the industry in the jurisdiction in which its implementation is being considered. There are, however, several considerations which must be evaluated to determine its effectiveness in accomplishing the goals of regulation and free markets.

First, are the market segments in which deregulation is being considered truly competitive, and is that competition likely to be
sustained? If customers who, in reality, have few competitive alternatives to local operating company access, switching, and toll services are excluded from the protection of the social contract, then the opportunities to extract monopoly profits from them will be substantial. The social contract model is appealing because it provides a reasonable way to limit the potential for cross-subsidization of competitive services by captive customers, and it has the attractive aspect of ease in implementation. If, however, prices to captive customers rise to such a level that they exceed marginal costs (a situation which could well arise in telecommunications, given the capital underrecovery problem and the current declining cost structure of the industry), then captive customers' rates could eventually provide a significant margin over what cost-based rates would provide. In such a situation, the margin on sales to captive customers could then be considered as a cross-subsidy allowing for predatory pricing of competitive services. In addition, if the industry is characterized by declining costs, the social contract model may well result in the failure to pass along to captive customers the cost savings associated with improved technological efficiencies or savings resulting from increased productivity.

**Surrogate Market Price Model**

The surrogate market price method has been discussed most in relation to the gas and electric industries and is designed to ensure that captive utility customers, who rely exclusively on their local utility company to purchase production services for them, are charged a price which reflects the price that customers with the ability to purchase these services directly in the production market are likely to confront. The concept involves net-back pricing, which is being discussed primarily in relation to setting prices in the gas industry, where gas is competing directly with oil. Under this model, the price of gas in the end-use market would be set at a level equivalent to, or discounted slightly from, the price of fuel oil. An alternative approach, which Charles Teclaw discusses in this volume, would be to allow local distribution companies simply to charge their customers the current spot market price for gas supplies regardless of the price the local distribution company actually pays.

This approach seeks to establish a market-clearing price which would be charged for end-use sales. Regulated transmission and distribution costs would be collected in that price, and the residual would set the wellhead price of gas on a net-back basis.

This method has analogies in the electric industry but differs in that it represents a net-forward pricing concept. Since in the electric industry few customers have alternatives to the production services of the monopoly provider, a market-clearing price would be estimated only for the generation component of the service. To that estimated market price, the regulated price for the monopoly components of the service would be added to get the end-use price.

The premise underlying the successful implementation of this model is the existence of a truly competitive market for electric generation and wellhead gas supplies. While steps are being taken in both of these industries which will enable us to determine whether a viable competitive market can be sustained for production services, it may well be premature to assume that these markets are sufficiently competitive and reliable to support such a pricing method. Without a truly competitive market for production services, there are significant difficulties in determining what an appropriate or accurate market-clearing price should be. The use of a surrogate market price involving a system lambda, or avoided costs for electric generation, or spot market price for gas supplies, may simply fail to reflect what the actual market-clearing price for these services would be if all end-users had the ability directly to purchase services in the production segment of the industry. If it becomes clear in the future, however, that sufficient competition exists in providing production services, the use of surrogate market prices as a substitute for prices based on cost of service to captive customers may well provide an opportunity and method for substituting competitive market forces for economic regulation.

**Full Deregulation**

For full deregulation to be possible in an industry, it would have to be determined that there is at least the potential for vigorous competition in every segment of the market. Absent that potential, there will always be captive customers from whom monopoly profits can be extracted and for whom the regulatory imperative will remain.

It may well be that in some or all of these industries it is only the transmission and/or distribution segments which con-
to exhibit natural monopoly characteristics, and, therefore, regulation can effectively control only these services and the prices charged for them. If that pattern emerges, open access to the bottleneck transmission and distribution facilities of the utility must be provided so that end-users can compete directly for services rendered in a deregulated production market segment. To date there remain entities with dominant market power and other institutional barriers limiting the degree to which deregulation can be implemented for production services. Many efforts now seem to be directed at eliminating those barriers and diutting the market power of certain service providers so that a greater degree of deregulation can be implemented in the production segment of each industry.

Conclusion

While the emergence of competition in both the production and end-use segments of these industries has focused concerns and discussion on ratebase regulation, it is important to note that many of the problems being experienced have not developed because of that regulation. Rather, they have developed because competitive opportunities have arisen from changing cost conditions in one or more segments of an industry. If anything, that competition has been stimulated more by economically inefficient pricing decisions made by industry and regulators than by inherent deficiencies in the ratebase regulatory model.

Nevertheless, the emergence of competition in regulated industries has a profound effect on the degree to which ratebase regulation can succeed in ensuring the same level of reliable service at reasonable prices as it has in the past.

Given these conditions, it would seem that the appropriate action for regulators to take would be to continue disaggregating services and unbundling rates. Such a process will provide the ability to continue the regulation of prices for monopoly services in the transmission and distribution segments, while providing the necessary separation of functions and costs to allow for regulatory forbearance of production services, if and when it becomes clear that those services are being provided in a fully competitive environment.

In closing, therefore, it seems clear that further structural changes in regulated industries are necessary before full imple-
Converting Dominance to Competition:
Criteria for Effective Deregulation

William G. Shepherd

Deregulation may now suffer from an excess of publicity and an overconfidence in its benefits. Various “deregulations” have occurred during 1975–1987 in a number of U.S. sectors. Yet there is confusion about what has been done, how large the benefits are, and whether the deregulation has been effective.


The confusion arises partly from an imprecise usage of the term deregulation, applying it to virtually every change of official rules since 1970.1 If deregulation has any scientific meaning, it is the replacement of government controls with effective competition. The most difficult case of deregulation is to shift a franchised, price-regulated, pure monopoly utility all the way to being an unregulated competitor in an effectively competitive market. That is the case focused on here. In sharp contrast, there are “easy” cases which merely open up an officially protected oligopoly cartel (such as among airlines, banks, trucking firms, and stockbrokers before 1975) to a greater degree of competition, by reducing the previous pro-cartel and anti-entry protections.

Among actual cases in utilities and transportation, controls have been removed from long distance telephone services, airlines, and railroads. Also, competition may soon be developed in some bulk electricity markets. Interesting though these changes are, none of them has yet completed a “difficult” case, going from dominance to effective competition. Airlines and railroads were already oligopolies, under only mild constraints on prices and profits. As for long distance telephone services, AT&T is still very much a regulated dominant firm, and it appears likely to remain so.

The U.S. experience of deregulation is therefore limited to “easy” cases, and the difficult terrain of complete pure monopoly deregulation has yet to be charted. Accordingly, there is a special need for clear general criteria for the future effective deregulation of difficult cases. Guidance is needed especially because the vested interests in each case issue conflicting claims about whether competition has become effective enough to make regulation unnecessary.2

The criteria appropriate for these cases are also the ones generally applicable for a wide range of cases. This paper offers such general criteria, in a condensed form and with brief explanations: A comprehensive justification of them would take more than the space available here. The criteria are debatable, but they are also straightforward. In fact, many of them are simply the criteria of effective competition itself, which voluminous research in the field of industrial organization has been clarifying for nearly a century.

The focus is on the dominant firm case, because it is the crucial transition phase on the way between monopoly and competition. The former regulated monopoly must somehow evolve down to a
market share below approximately 40 percent, if deregulation is to be effective.

At least one eminent observer regards deregulation as tortuous and frustrating, "the worst of all possible worlds," but surely that is too negative. Admittedly, deregulation is often complex, and its mixed conditions do not fit neatly into the old boxes of natural monopoly or perfect competition. Regulation often must be removed carefully, in sophisticated ways and sequences, under conditions of uncertainty.

But the task and the criteria need not be extremely difficult in practice. Indeed, the situation can be the best of both worlds—applying certain limited controls while also unleashing powerful competitive incentives—as long as regulation is withdrawn after competition has become effective. Premature deregulation is the prime danger; if it is avoided, the process can be made effective with moderate effort.

The paper begins with a summary of the conditions of effective competition, as contrasted with ineffective competition under market dominance. The main market-based criteria for deregulation are then given. Next, several other criteria are also discussed, dealing with core services, service quality, local service supply, and diversification. A discussion of how the criteria apply to three important cases—long distance telephone service, airlines, and bulk electricity—is followed by a brief concluding summary.

Criteria of Effective Competition

Market Structure

For effective competition, there need to be numerous firms on a comparable footing, able to apply equivalent pressure to one another. Otherwise, a dominant firm can use threats to deter its small rivals from strong rivalrous actions or even eliminate the small rivals altogether. The result would be weak competitive pressure on a firm which holds over half the market. In effective competition, no firm holds enough of the market to control pricing, output, or innovation.

Market Share. The market share of the leading firm or firms is therefore of first concern. Research has shown that market power usually begins to be appreciable, with significant effects on the market outcomes, when the leading firm's market share rises above the 15-20 percent range. Market power usually increases steadily in line with further rises of market share, so that market shares of more than 40 percent almost always provide substantial market power, especially when there is no close rival.

For competition to become effective in a formerly regulated monopoly market, the monopoly firm must lose its monopoly power and be put under effective competitive pressure. Therefore, the analysis of effective deregulation must focus on the case of the dominant firm, which is commonly defined to have (1) a market share of more than 40 percent and (2) no close rival. Such a firm usually has a high degree of market power because no equivalent rival exists capable of disciplining it.

Accordingly, the dominant firm can usually influence prices, innovation, and other market outcomes in its favor. Competition is not effective, although the dominant firm will commonly assert that its small rivals apply strict pressures. The competition the small rivals can provide is usually weak, unable to challenge equally the dominant firm's full set of resources.

Comparable Rivals. Effective competition requires a continuing struggle among at least several comparable rivals. That struggle may exist at times under duopoly, that is, when two firms divide most or all of the market approximately equally between them. But the duopolists have strong incentives to cooperate toward the pure monopoly outcome, and therefore effective competitive action between them may occur only infrequently. Tight oligopoly, whereby the leading four firms have at least 60 percent of the market, may provide effective competition more frequently, but it also has strong tendencies toward collusion.

Duopoly and tight oligopoly are the range in which effective competition may begin to prevail, as a regulated monopoly evolves downward toward effective competition. But the firm's market share must sink from 100 percent down through the dominant range to less than 40 percent, and rivals must emerge with sizable market shares of their own, before competition can be relied on to be effective in place of regulation.

Barriers to Entry. Limits on potential competition can be another element of market structure. They may arise from the dominant firm's control over a key resource, advantages in raising capital, economies of scale, regulatory rules, or other causes. Low barriers
to new competition help to ensure that competition is effective. But they are not sufficient in themselves to ensure effective competition, despite recent claims that ultrafree conditions of entry (so-called contestability) can absolutely efface all structural conditions within the market. Nor are low barriers strictly necessary for effective competition if the structure within the market is already fully competitive. But in duopoly or tight oligopoly, the probabilities that effective competition will prevail can be improved by low entry barriers.

**Behavior**

Collusion. Structure does not tightly determine competitiveness, especially in the oligopoly setting. There is a range of behavioral variation. The rivals may cooperate so as to give a monopoly outcome; or, at the other extreme, they may adopt strictly combative policies, approximating effective competition. Since oligopoly behavior is commonly indeterminate within this range, observing the firms’ behavior (and not just their structure) may be necessary to determine whether competition is effective.

Collusion on prices is a key indicator of oligopoly collusion. There are also more comprehensive forms of collusion observed in foreign cartels, including output controls and unified marketing policies, or even profit pooling and the allocation of the firms’ investment.

**Actions to Harm Competitors.** Another direction of behavior is a dominant firm’s unilateral use of selective anticompetitive actions (in pricing, product changes, or other ways) so as to harm or eliminate its much smaller rivals. Even if no single action can be proven to be “predatory” by price-cost tests, a pattern of selective actions can be a sign that the dominant firm is effectively reducing competition.

Therefore, anticompetitive behavior may involve either (1) collusive price-raising actions or (2) unilateral selective price cuts (or similar actions) designed to harm or eliminate competition.

**Performance**

Now we need to review the benefits that effective competition can provide. Their relative sizes are important, and they are often misunderstood.

Effective competition yields several elements of good economic performance. Prices are restrained to costs, and excess profits are not attainable except by superior costs and innovation, or by luck. One result of this equating of prices and costs is an efficient allocation of current resources, the economist’s static Pareto equilibrium, which maximizes consumer and producer surplus throughout the economy. A second result is the minimization of firms’ costs, under tight management; so-called X-efficiency (as distinct from Pareto allocational efficiency) is encouraged by tight competitive pressures on firms.

A third element of performance is optimal innovation (which usually means rapid innovation), to give lower costs and better products. Competition tends to force innovation to be faster, and it gives a wider variety of experimentation and creativity. Fourth is equity, or fairness, in income, wealth, and opportunity. Monopoly tends to enrich the few and to restrict opportunity. Finally, there are broader elements of good performance, including freedom of choice and social diversity. Competition promotes them, too.

Although effective competition tends to provide all of these elements, the sizes of the effects differ. Allocative efficiency gains are usually estimated in the range of 0.5 to 1.5 percent of GNP. X-efficiency benefits of competition are generally regarded as 3–5 percent of GNP. The gains from faster innovation are thought to be even larger. Taken together, the research lessons are that X-efficiency and innovation are the most important economic benefits, while Pareto efficiency is of lesser scope and urgency.

Because the benefits of competition are large, it is wise to take special efforts to promote it. Static efficiency (in price and output results) is not the main aim, although it can be significant. Especially if (as in dominant firm cases) competition is weak, then efforts to make competition stronger can be crucial.

**Technology and Costs**

The only exception to competition’s role occurs when economies of scale are so large that effective competition is not viable. There may then not be enough “room” for effective competition, because minimum efficient scale is a large fraction of the entire market. If that is so, then competition is not spontaneously viable, as readers of this volume will know. Competition may need to be reinforced or replaced by some form of effective regulation.

Therefore, the nature of costs may be critical in assessing the possibilities for effective competition. Although costs are often not
easily determined, because there are alternative technologies and viewpoints about them, the main lines of probable costs need to be explored carefully. Often it is reasonably clear whether four or more comparably efficient firms can coexist in the market.

Criteria for Effective Deregulation

The main lessons for deregulation follow directly from these analytical criteria, and they focus on the dominant firm case. I state the criteria here in brief, perhaps oversimplified.

Aim toward full deregulation only if technology is likely to permit effective competition, with enough room for numerous competitors. One must base that judgment on careful appraisals of the cost patterns that will hold with the best new technology. Remove regulatory controls and price only after effective competition has been established, not before. Otherwise, the dominant firm may smother its competitors and prevent competition from reemerging. It follows that the regulators need to retain control of prices as long as there is dominance. Both price ceilings and floors will continue to be necessary. Only when the leading firm’s market share goes below approximately 40 percent—and there are three or more comparably strong rivals—can competition be regarded as effective. In addition, any barriers to entry must be only moderate to low, so that new entrants may prevent duopoly or tight oligopoly from generating collusion.

Where it is necessary, in order to put competitors on a comparable footing, constrain the dominant firm more tightly than its rivals. Although this may draw accusations of unfairness, it is necessary to redress the competitive imbalance and make competition effective. In particular, regulators need to prevent selective anticompetitive actions by dominant firms against rivals with much smaller market shares. “Predatory pricing” is just one class of actions within this general category. The key criterion is dominance, once again. The dominant firm can engage in a series of actions which harm or eliminate its rivals. The small rivals usually cannot mount comparably effective actions because their strategic resources are much smaller. Defining and measuring selectivity may often not be a simple matter, but applying the general approach is important.

Note that no limits need be placed on the smaller rivals. Firms with small market shares cannot hurt competition by any strate-

gies they may use against much larger firms or one another. Instead, they can only intensify competition.

Permit free entry so as to explore the viability of competition, but do not rely on potential entry alone to neutralize dominance. Only actual competition can reasonably be looked to for possible strong pressure.

Prohibit horizontal mergers which will reestablish dominance or create other market shares above 20 percent. This fits research which finds market power effects as shares of about 20 percent (or lower in some cases). It also fits the general rules applied to mergers in other markets by the antitrust agencies. Continue to use profit rates as a criterion in assessing the effectiveness of competition. It is true that profit rates are often deceptive to measure, and they may reflect differing causes (monopoly power, scale economics, efficiency, random luck, and so forth). Nonetheless, excess profits by dominant or tight oligopoly firms are a presumptive indicator of market power, to be rebutted only by definite evidence of scale economies or superior efficiency. At the same time, subnormal profits by smaller rivals indicate that they are failing firms rather than effective competitors.

This completes the main criteria that are based on the mainstream analysis of competition. Next discussed are criteria based on other conditions more specific to these regulated sectors.

Further Criteria for Deregulation

Core Services

Most regulated sectors contain certain operations that are regarded as, or merely claimed to be, the essential core or network which makes the whole system’s service possible. Other services are adjacent: ancillary, normal, or ordinary, in some sense.

Core services are not uniquely defined. They may be those which have the greatest relative economies of scale. Often they share joint costs of production. But scale economies and joint costs are neither necessary nor sufficient to classify them as core services. They may simply be regarded as the unifying or crucial part of the system. Table 1 gives several instances of core services.

Core services are often controversial, for the established firms have an interest in contending that the core is large, even if it is not. Core services are usually pivotal in any argument that the
Table 1. Examples of Possible "Core" Services

<table>
<thead>
<tr>
<th>Sector</th>
<th>Possible &quot;core&quot; services</th>
<th>Currently provided by:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Airlines, air freight</td>
<td>Airports</td>
<td>Public Agencies</td>
</tr>
<tr>
<td></td>
<td>Flight guidance systems</td>
<td>Federal Aviation Authority</td>
</tr>
<tr>
<td></td>
<td>Reservations systems</td>
<td>Each airline</td>
</tr>
<tr>
<td>Trucking, intercity buses</td>
<td>Highways and roads</td>
<td>Public agencies</td>
</tr>
<tr>
<td>Broadcasting of radio and TV</td>
<td>Spectrum allocation</td>
<td>Federal Communications Commission</td>
</tr>
<tr>
<td></td>
<td>controls (?)</td>
<td></td>
</tr>
<tr>
<td>Satellite communications</td>
<td>Satellite launching</td>
<td>National Aeronautics and Space</td>
</tr>
<tr>
<td></td>
<td>systems</td>
<td>Administration</td>
</tr>
<tr>
<td>Telephones</td>
<td>Local switching and</td>
<td>Telephone companies</td>
</tr>
<tr>
<td></td>
<td>loops</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Intercity routing (?)</td>
<td>Bell System</td>
</tr>
<tr>
<td>Postal service</td>
<td>Local delivery routes</td>
<td>Postal system</td>
</tr>
<tr>
<td></td>
<td>Local sorting</td>
<td>Postal system</td>
</tr>
<tr>
<td>Electric Power</td>
<td>Generation (?)</td>
<td>Electric firms</td>
</tr>
<tr>
<td></td>
<td>Local Distribution</td>
<td>Electric firms (private and public)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>By agreement among electric systems</td>
</tr>
<tr>
<td>Banking</td>
<td>Check clearing</td>
<td>Federal Reserve System</td>
</tr>
</tbody>
</table>

The degree of separability is often unclear, particularly to regulators and other outsiders. Moreover, separability is often not exogenous to the firm but rather partly under the firm's control, for two reasons. First, the firm can select the technologies with the largest elements of system unity (of joint production and overhead cost). That maximizes the firm's supposed need to control the whole system. Second, the firm can conduct its operations and cost accounting in ways which make the joint costs and overhead costs seem as large as possible.

When these two conditions occur, the apparent marginal costs for individual outputs will be minimized, giving the utility the widest discretion in its pricing actions toward rivals—and in its pricing reactions to new competitors. This will reduce the ability of actual competitors to survive and of potential competitors to exercise restraint upon the firm.

If true economies of scope are large, there may exist a set of true core services. If core services are separable from the rest, they can be provided either by the utility firm or separately by some other unit—perhaps a public agency, such as the public provision of airports and FAA flight guidance. To that extent, the viability of competition under deregulation will be enhanced. Table 1 indicates that separability can indeed often be complete, so that core services (as in airlines, air freight, trucking, and banking) are provided separately.

Since core services do not necessarily have large economies of scale, they do not necessarily create or tend toward a natural monopoly. Moreover, core conditions may change or fade away as new technology develops. There have been marked reductions of core conditions in a variety of sectors. Indeed, the recent deregulations in various sectors have mainly followed the shrinkage or disappearance of core conditions. Therefore, the regulated firm bears a burden of proof to show both that its claimed core conditions do exist in compelling degrees and that there are no alternative technologies without core conditions.

This leads to the criterion for deregulation: Only core services which are proven to be large, irreplaceable, and inseparable from the rest of the services should be allowed to justify the retention of monopoly positions. Even then, the monopoly must prove that the conditions exist and that the cost gradients are steep. Any limits on competition should be tailored to fit only those proven...
core services. Those services should continue to be regulated and should continue to be monitored for future separation as soon as that may be possible.

Service Responsibility

Under regulation, the franchised firm bears exclusive responsibility for providing service. The advent of competition removes that exclusivity, but the incumbent firm is commonly required to remain responsible for adequate service, in case its rivals fail and withdraw. The incumbent may also be required to provide capacity for its new rivals to use; examples include AT&T providing MCI and Sprint the use of “its” system and private electric firms having to let municipal systems gain access to distant bulk power through “their” private transmission lines. The incumbent firm resents and resists this added burden, which can indeed raise awkward problems of combining coordination and competition.

Yet, that burden must be borne if competition is to develop. The alternative is to divide off the trunk system for separate ownership, with equal access open to all. That is one way to make competition compatible with service responsibility. The other way is to have the former monopolist remain directly responsible for providing service as long as it retains a market share above approximately 40 percent. When its share drops below that level, then it becomes just another competitor and has no special responsibility for the adequacy of service throughout the market.

There may be some anxiety that service will be less reliable because “nobody is responsible for it” but that supposed hazard is only an illusion. In virtually all industries (regulated and unregulated), goods and services are provided steadily and reliably by several or many competitors, even though no one firm is required to accept any legal obligation to serve. In markets ranging from aircraft, banking, and oil to housing and food, the force of competition and profit-seeking induce an adequate supply to be provided.

Of course, there may be occasional lapses or inadequacies in supply, from one firm or several in the market. But such lapses also occur occasionally in the exclusively regulated monopoly utilities. The idea of an absolute, ironclad responsibility of franchised utilities for service at every moment is an objective, not a fact. Accordingly, competition’s dilution of formal responsibility is merely a matter of degree. Furthermore, customers can usually adjust, if it is necessary, so as to be less reliant on utility service. Industrial customers often have their own reserve power sources to tide them over during electricity failures. Families can adjust their consumption habits and appliances so as to be less vulnerable. These adjustments to lighten the future effects may involve some higher costs, but the costs may usually be small.

In short, service responsibility is already less than absolute in practice. A shift to effective competition may actually increase service reliability, rather than reduce it, by providing a large number of vigorous, alternative suppliers in place of a single source. The criterion for deregulation is: As long as a firm retains a dominant position, it continues to bear the burden of formal service responsibility, including rivals’ access to “its” system. One reward for sinking below a 40 percent market share is to escape that responsibility.

Local Service

Deregulation commonly stirs complaints that it will cause service to small-town users to close down.7 Recent examples of this claim include telephone, bus, truck, railroad, and airline services. In each case, there were aggressive claims that small-town services would disappear.

The incumbent sellers claim that they have been “cross-subsidizing” the costly small-town services with profits from their profitable, high density main routes. New competition will fasten upon the profitable denser routes, they say, and skim that cream, so that the unprofitable small-town routes will either have to be closed down or priced much higher. Therefore, competition is portrayed as a threat to the Jeffersonian values of a democratic small-town America. In political terms, it threatens the viability of thousands of smaller towns in rural regions throughout the country, which often wield disproportionate influence in elections and legislatures.

The danger has some analytical validity. As shown in simplified form in Figure 1, average cost of service may decline with the size of the route. Thus, on high density truck and telephone routes, average costs per unit are often much lower than on the sparsely used peripheral routes to (and among) small towns out in the
Yet, the real threat is often much smaller than is claimed. The
costs of small-town service may not be as high as the monopolists
assert and often are debatable because of joint and overhead costs.
And often the “rural” groups turn out to be well-to-do gentry
living in affluent suburbs, rather than the prototypical poor farmer
or artisan.

Moreover, the technology of supply can often adjust and thus
maintain service at lower costs and prices. In air travel, for ex-
ample, the main airlines have cut back their flights by full-size jet
aircraft to smaller airports. But smaller “commuter” planes have
emerged to take their place on many thin routes, at costs lower
than for partly filled large jets. Therefore, the actual costs have
been much lower for small-town traffic than the curve in Figure
1 suggests. Much the same may be true of other industries using
alternative technologies to serve these peripheral routes.

Even if small-town service does involve some financial losses,
they may be measurable and compensable by direct public pay-
ments. Those payments may be small compared to the benefits of
X-efficiency and innovation which competition will deliver.

The issues are not simple, but the experience so far suggests
that this danger is frequently an illusion, used by incumbent firms
as an argument in defending their monopolies. The best regulatory
approach has two parts. The first is to carry out independent
studies of the actual costs on thin routes, covering alternative
technologies where possible. Do not rely on the monopolist’s cost
estimates, for they reflect not only self-interest but also the narrow
technological choices based on the past monopoly-oriented system.

The second part is to compare any provable small-route losses
against the benefits competition is likely to provide. Small losses
in a few locales can often be covered in order to realize the large
gains from competition throughout the industry.

**Diversifying**

As deregulation proceeds, firms often make ambitious moves
to diversify, even into markets wholly unrelated to the original
utility services. Regulators often resist this, for several important
reasons. First, diversification can divert managerial attention and
commitment from the established activities. Also, it adds finan-
cial risks to the whole enterprise and may cause the firm’s cost of
capital to rise. And if a financial crisis does occur, it may undercut
the firm’s ability to meet its utility responsibilities. This problem is aggravated if the pooling of finances between the old and new activities makes it hard for the regulators to assess the firm’s actual financial soundness in its utility operations. Moreover, the firm may be able to use its market power in the utility lines so as to gain unfair advantages in the new lines. Prudent regulators may therefore resist all diversifying.

The correct criterion, instead, is more specific, following directly on the earlier analysis of dominant firms. Only dominant firms may raise problems by diversifying. Fully competitive firms can be left free to diversify as they choose. Diversifying by dominant firms may indeed endanger the basic service responsibility and frustrate regulation, as well as endanger effective competition in the new markets. Regulators may therefore properly require that risky, unrelated lines not be added by a dominant firm and that the finances of utility and other operations be kept separate. As in other matters, the firm gains freedom from these limits only by losing its dominance.

Rellying on Antitrust Agencies

One often hears that the problems can be left to the antitrust authorities (the Antitrust Division in the U.S. Department of Justice and the Federal Trade Commission) to solve. It is true that the criteria do deal with monopoly and competition, as do the two agencies. Yet, the agencies will not usually be adequate, for the following reasons.

First, the antitrust agencies are very small units compared to their awesome responsibilities covering most of the U.S. economy. Their resources are tiny and are stretched even in dealing with existing industrial coverage. Adding major utility sectors to their burdens is asking for weak handling.

Second, their methods of enforcement are narrow. The agencies can only bring lawsuits to stop specific anticompetitive conditions or actions. They cannot exercise continuing formal or informal control over complex conditions.

Third, the dominant firm case is precisely the one which the antitrust agencies are least fit to handle. Effective deregulation requires sustained attention and constraints in moving the monopolist down below 40 percent of the market, preventing anticompetitive actions, and enforcing service responsibilities along the way.

The agencies have repeatedly shown in large lawsuits that they cannot persuade the courts to deal effectively with dominant firm conditions, even in much simpler cases. Regulation was created precisely to fill the gaps left by these agencies.

Fourth, the agencies go through sharp changes in quality and political direction. Until 1980, these changes were real but usually only moderate. Since then, antitrust in the United States has encountered a radical decline. Reagan officials have abruptly cut the agencies’ resources and converted them to lax enforcement. Under the dogma that controls current officials, dominance is benign or even to be preferred. Monopoly positions, they say, only reflect the firms’ superior efficiency. Since these political appointees have largely lost touch with market realities, it is not prudent to rely on the agencies to apply effective policies.

In short, the antitrust agencies are too small, their methods of enforcement are not suitable for deregulation, and their judgments are unreliable. They fail especially on the crucial case of market dominance. Regulators will need to rely on their own powers, information, and expertise in converting dominance to effective competition.

Applying the Criteria to Two Cases

The approach taken here—which is pivoted on market shares—drastically simplifies the deregulatory criteria by applying clear guidance for the crucial case of market dominance. Where dominance exists, certain regulatory limits are needed; where it has yielded to effective competition, all regulatory concern and limits can cease.

Two prominent examples—AT&T in long distance telecommunications and integrated private utility firms in bulk electricity markets—can illustrate briefly how the criteria may be applied.

AT&T in Long Distance Telecommunications

Although it has lost its pre-1975 complete monopoly of long distance service, AT&T retains clear dominance. Defining the market can be debated, but by any reasonable definitions, AT&T’s market share is probably above 75 percent in the main mass of the market, with no rival above 10 percent. No “contestability” conditions for ultrafree entry are present, able to constrain AT&T tightly (or perhaps even moderately). Indeed, several of the small
rivals offer only past failures and continuing financial losses in contrast to AT&T's strong profitability and large resources.

Therefore, all the criteria about dominance continue to apply. Price constraints are needed, both (1) general ceilings against general monopoly pricing and (2) specific floors against selective anticompetitive pricing. Profit rate constraints are still appropriate. New entry is to be encouraged, including virtually unlimited entry by regional Bell companies; indeed, these may be virtually the only sources of effective competition against AT&T. The regional "Baby Bells" have developed surprisingly strong tendencies to compete against their former parent. This pressure can be usefully engaged, particularly because the existing small long distance competitors are proving to be vulnerable.

Much of the long distance network appears to be a set of "core services," and so the efforts to cost them separately and regulate access to them continue to be necessary. If the network could be separated out for operation by a separate entity, equally available to all comers, then effective competition would be more likely.

As the dominant firm controller of the network, AT&T must accept continued responsibility for service reliability. It also needs to continue to provide service to peripheral routes, as parts of the full system.

Finally, AT&T should not be permitted to diversify into non-complementary lines nor to mingle its finances between long distance service and other activities. Otherwise, the reliability of the entire system may be reduced.

These criteria are stated concisely here to bring their lessons out clearly. In practice, the criteria may need to be adjusted to fit special conditions and marginal situations. But the clarity and power of the dominant firm basis should be evident. It establishes a system of consistent benchmarks from which any deviations must bear a heavy burden of proof.

**Bulk Electricity Markets**

It is now well recognized that meaningful bulk electricity markets exist in various regions and could be opened up for competition.\(^{22}\) Many of them are capable of effective competition, with relatively low concentration and a variety of comparable cost sources of supply. Moreover, there would be a variety of buyers of power, many of them large enough to exert strong pressure to

break up any tendencies to collusion among the sellers.

But vertical integration between the transmission and retail-distribution levels currently blocks the emergence of effective competition. The integrated private companies are both (1) the major suppliers of bulk power at the transmission level and (2) powerful rivals of publicly owned systems at the retail level. This permits the private systems to control their retail rivals' access to bulk supplies and to set or manipulate the prices they charge those rivals for their key input. Accordingly, the playing field is not level.

Only if integration were dissolved would bulk supply markets have a chance to become effectively competitive. Some initial steps in that direction may be emerging in areas involving Chicago, Virginia, and New York. Moreover, there have been experiments in bulk supply marketing in the Southwest, and monopsony pressure is being developed by public system pooled buying in other regions. But it will take added changes, such as divestiture, to set the basis for fully effective competition.

Even if that happens, regulators will still need to define markets and retain controls on firms that may hold dominant positions. Electric markets may be difficult to define sharply, because power can be transmitted over long distances at graduated cost differences. Therefore, dominance may be hard to identify and control.

It may be necessary, instead, to treat transmission as a core service, dividing it out to be coordinated in a separate nation-wide transmission entity, or possibly in several regional systems. Access could then be open and fair, and dominance in bulk supply would cease to be a problem.

Dominance in retail distribution of power would remain, however, and the standard criteria would apply. Price constraints would still be needed, and service responsibility and obligations to serve peripheral areas would continue to apply. Diversification would be restricted, including take-overs by firms located in other markets.

Since competition in both bulk and retail electricity is still limited, the practical criteria for deregulating either level have to be imprecise at this point. But if competition does develop, the basic criteria will provide useful guidelines for the eventual deregulation.
Criteria for Effective Deregulation

Summary

The dominant firm case is the proper focus for understanding the criteria for moving from a regulated monopoly to effective competition. Its lessons are generally clear, and they may seem to be radical, but they follow directly from the economic analysis of dominant firm markets.

The general lesson is that dominance requires continuing constraints on prices, profits, and tactics. The dominant firm continues to bear responsibilities for systemwide service reliability, including in peripheral parts. And its diversification may need to be constrained. All these needs come to an end when the dominant firm sinks to be just another one among at least several strong competitors. Without that shrinkage, regulation stays.

This clarity in the basic issues does not guarantee the practical policies will be easy to apply. Defining the markets and determining market shares may be difficult in some cases. Moreover, the need to retain regulatory restraints until the dominant firm’s position has actually dwindled away may seem to be discouraging, or possibly not realistic. Just “letting competition take over” has seemed to be such an attractive, straightforward, and easy solution. Yet, this particular lunch is not free, and competition must be carefully nurtured and promoted until it is truly effective. Abandoning regulation before that would be irresponsible.

The resulting transitional mixture of regulation and partial competition may actually provide a robust combination of relatively lower prices, good service quality, and rapid innovation. That is the opposite of Alfred Kahn’s “worst of all possible worlds.” But the regulators must take careful and sophisticated actions to make sure that the good results occur. It is idle to hope for quick, easy competitive solutions.

Notes

1. The sectors include intercity buses, truckers, movers, air freight, passenger airlines, railroads, natural gas, stockbrokers’ fees, various forms of banking, cable television, various parts of the telephone sector, radio and television broadcasting, and various lesser instances. The policy changes include a reduction/removal of entry barriers, as ending/removal of price constraints, adjustments in rules toward service quality, the reduction/removal of support for cartel pricing arrangements, and other lesser changes.

2. Airlines and long distance telephone are good examples of this. Whether airline deregulation has succeeded overwhelmingly or is still under strong oligopoly joint-maximizing patterns is an open debate. And AT&T demanded removal of price constraints on long distance service as early as 1984–1985, when it still held about 90 percent of the market; AT&T then had only one profitable competitor (MCI), whose market share was below 5 percent.


6. This is true regardless of the origins of the high market share, whether it arises from monopolizing actions, scale economies, luck, or some specific superiority in the firm’s efficiency or innovation. The market power occurs in any event. Research has shown that economies of scale are usually not a major cause of market share higher than 20 percent in major U.S. industries; see W.G. Shepherd, “Economies of Scale and Monopoly Profits,” chapter 9 in John V. Cravens, ed., Industrial Organization, Antitrust, and Public Policy (Boston: Kluwer Nijhoff, 1983). Among 85 firms with market shares of more than 20 percent in the 1960s, scale economies accounted for only 1–15 percent of their supernormal profits.

7. The definition has become common usage in the research literature, including the subfield of research on the dominant firm case that has emerged in the 1980s. Some researchers would place the threshold value as high as 50 percent. Prominent U.S. cases include IBM in mainframe computers, Gillette in razor blades, and Eastman Kodak in photographic film. Marginal cases, where the next largest firm has about half the dominant firm’s market share, include General Motors in automobiles before 1980, Kellogg in breakfast cereals, and Procter & Gamble in detergents.

8. These resources include the volume and terms of access to financial support; the ability to deploy and concentrate large advertising efforts among
a range of specific market segments; research and development skills and funds which can respond quickly to small rivals' incursions; and the ability to adopt sharp price discrimination to anticipate rivals' competitive moves and to react against them. Accordingly, the smaller firms commonly seek market niches in narrow specialties. The dominant firm tolerates them as long as they do not challenge its marketwide control, but it is capable of eliminating them at any point by exerting sufficient resources.


10. For an extensive critique of the ideas, see my "Contestability" versus Competition." The main statement of "contestability" is in W.J. Baumol, J.C. Panzar, and R.D. Willig, *Contestability: The Theory of Industry Structure* (San Diego: Harcourt Brace Jovanovich, 1982). See also Marius Schwartz, "Basic Conditions of Contestability," working paper, Antitrust Division, Department of Justice, Washington, D.C., 1986. Despite its popularity among some theorists as a technical subject, the "contestability" concept has been given virtually no empirical support, and it has been largely rejected in the field of industrial organization as little more than a curiosity. Yet two members of the Baumol group continue to boast about the idea; see W.J. Baumol and R.D. Willig, "Contestability: Four Years after the Book," working paper, Department of Economics, New York University, 1986.

For regulation, the value of "contestability" is minimal, since it assumes perfect conditions which are far removed from regulatory reality. For example, the theory assumes that the can replace the incumbent totally and instantly; thus, MCII would replace AT&T on line, immediately, by setting its price a little lower: The airline sector had been claimed as the prototypical "contestable" market because its aircraft can shift routes quickly. Yet, the Baumol group has admitted that the industry actually does not fit the theory. Other flaws in the idea, including a logical contradiction between two key assumptions, are noted in my 1984 paper.

11. This behavioral indeterminacy is stressed by Chicago School economists, who argue that structure has little or no influence. The matter is one of degree. No "structuralists" claims that structure exerts tight control over behavior and performance. Rather, structure has some degree of influence, possibly strong in many cases and weaker in others. Most knowledgeable observers of markets, and most specialists not specifically in the Chicago tradition, recognize that structure usually has significant influence. The strong tendency toward collision is shown in the classic article by George A. Hay and Daniel Kelley, "An Empirical Survey of Price Fixing Conspiracies," *Journal of Law and Economics* 17 (April 1974): 13–38. In

12. See my "Assessing "Predatory" Actions by Market Shares and Selectivity," *Antitrust Bulletin* 31 (Spring 1986): 1–28, for the concepts involved in defining "anticompetitive" actions. Because their resources and market coverage are greater, dominant firms can use selective actions to overwhelm small rivals. Therefore, selective actions by dominant firms will need to be constrained if competition is to be made effective.

As for pricing, discrimination is the key problem: a difference between price-cost ratios on identical or related goods. Two criteria determine whether a specific instance of discrimination is pro- or anticompetitive. One is the market share of the firm doing the discriminating, compared to the target firm. A substantial market share advantage (such as 25 percent or more) means that competition is unbalanced. The other criterion is the degree of systematic discrimination. Thorough, rigid pricing tends to reflect and increase market power.

In applying these criteria, for example, systematic discrimination by a firm with 60 percent of the market targeting a firm with 10 percent would be anticompetitive. Done sporadically, or by a firm with, say, a 30 percent market share against another firm with 30 percent, it would be harmless to competition.

13. This is the traditional natural monopoly problem, which also includes the natural dominant firm case. Either direct price regulation or some set of constraints on the dominant firm, as discussed in this paper, are the necessary.

"Contestability" will not be a useful answer to the problem, for reasons already noted above. Entry may apply some degree of constraint, at least for (1) small markets which (2) face large, powerful potential entrants and (3) which have pure conditions of ultrafree entry. But such conditions are rare in utility sectors, and they are hard to measure in any event.

14. See especially the merger guidelines issued by the U.S. Department of Justice's Antitrust Division, setting forth the main lines of antitrust limits on mergers. These rules have been greatly loosened since 1980 by Reagan administration officials, and so a 20 percent upper bound can be regarded as quite liberal. The recent changes suggest that the Antitrust Division and the Federal Trade Commission cannot now be counted on to apply the rules consistently in dealing with evolving former utility sectors. Nor can the conventional regulatory agencies (such as the Interstate Commerce Commission or the Federal Energy Regulatory Commission) or government departments (such as the Department of Transportation) be relied on to apply economically sound restraints.

15. These two sections on core services and service draw upon the discussion.
Criteria for Effective Deregulation

in my "Competition and Sustainability," in Thomas G. Gies and Werner Sichel, eds., Deregulation: Appraisal before the Fact (Ann Arbor: Division of Research, Graduate School of Business Administration, University of Michigan, 1982), pp. 13-34.


17. This section draws upon chapter 14, "Deregulation," in my Public Policies toward Business.


20. This is evident in Shepherd, Public Policies Toward Business, and Philip Areeda and Donald F. Turner, Antitrust Law, 5 vols. (Boston: Little, Brown, 1978). Of course, the 1984 divestiture by AT&T stands as a major exception to this rule, but it involved uniquely favorable conditions which are unlikely to recur.

21. It should be noted that expert witnesses for AT&T have denied this fact in various legal and regulatory forums. There is no independent research basis for that view, however.

Serving Two Masters

Joelyn K. Murphy

I have been asked to address the question, "Can an electric utility company successfully serve two masters: regulators and the competitive market place?" The answer, I think, is no—at least not over the long term. However, I also think that both masters can be well served if regulators allow the electric utility industry to restructure itself.

But before looking into the future to see how the utility industry might be restructured so that both masters can be served, I would like to cast a glance back into recent history to see how we came to be serving these two masters today.

For about a hundred years, the utility industry pursued one central business strategy: to meet its obligation to serve, its obligation to supply all demands at the lowest cost, by building capacity to meet its load forecast.

For the last several decades, load had grown consistently at about seven percent a year, which meant that capacity had to double every ten years to keep pace. In the early 1980s, however, load growth decreased significantly: from seven percent a year to about three percent a year. Given the long lead time necessary to bring a plant on line, this extraordinary decrease in demand resulted in large amounts of excess capacity.

On the supply side, we pursued economies of scale in generation plant and built ever larger plants, creating the familiar stairs effect of capacity additions. Because of the economies of scale, however, the effect of plant coming on line, used to result in lower rates for customers more often than not.

At the same time that demand took a nosedive in the early 1980s, cost overruns hit the nuclear industry with a vengeance. Before 1981, nuclear plants came on line at an average cost of $400 an installed KW. They are now coming on line at an average cost of $2600 an installed KW. This change in the cost function resulted in "rate shock."

The combination of rate shock from high cost plants and excess capacity from decreased demand in the early 1980s changed fundamentally and dramatically the industry's business environment.

From the perspective of business strategy, the most important factor for success in the electric utility business historically had been to keep the capacity additions as close as possible to the forecasted load growth. (See Figure 1.)

The fact that after 1981 demand decreased so precipitously at the same time that the cost of capacity increased so rapidly meant that the capacity additions "curve" and the load growth "curve" quite suddenly broke apart. (See Figure 2.)

That breaking apart, and the customers and regulators response to it, led to a complete change in the ground rules for how utility business is conducted and how it is regulated.

Most notably, the social compact became asymmetrical. The industry went from the symmetry of having an obligation to serve with a franchise to the asymmetry of having an obligation to serve with competition.

Several changes in the fundamentals of the business were then at work creating strong and I would argue, irreversible pressures for competition.

One of those changes, of course, is technology. Looking backwards, nuclear technology and its drive-up of electric rates made other supply options competitive when they had previously looked uneconomic. Looking forward, the commercialization of micro co-
generators would obviously expand the array of viable competitive alternatives.

Another change is more philosophical: small business and entrepreneurs have become very fashionable these days. The thought of helping mom and pop windmills get started has a certain romance to it. The structure of the market is also changing. Customer segmentation has, at last, come to the utility business. We now talk about unbundling and rebundling services in all those marketing seminars we find ourselves going to these days.

Another fundamental change occurs when an institutional or psychological barrier is broken, when somebody breaks out of the mold and says “things can be done differently.” Transco, for example, broke a barrier and set the stage for deregulation of gas utilities when it opened its system to third parties in 1983. Within three years, the gas industry was markedly different. The proposed leverage buyout and the eventual hostile takeover of Alamito in Arizona in 1986 broke a psychological barrier within the electric industry. I think that within five years we will see a very different structure of the electric utility industry than we do today.

Yet another change stems from the accumulated effects of social rate making, or what was referred to earlier today as “inefficient decisions of regulators” that result in cross-class subsidies. When regulators adopt rate designs that allow, for example, industrial customers who do have options to subsidize residential customers who do not have options, then those regulators are creating a fertile ground for competition, whether or not they profess to like it or it they.

Diminished load growth and excess capacity also create pressures for competition. It is always much easier to talk about competition and deregulation in conditions of surplus than in conditions of scarcity.

Lastly, the regulatory rules for cost recovery of capital investments have changed dramatically. I am referring here to the new regulatory craze of prudence audits. These have had a massive impact on the utility industry, currently through huge write-offs, disallowances, and phase-ins, and in the future as a swift and pen-
The answer to the question, "Will we have an adequate supply of electricity at the lowest possible price in the future. My guess is that we will see very little new capacity brought on line under traditional regulation by traditional investor owned utilities. Most of the future capacity will be brought on line, I suspect, in this zone under very different rules of risk and reward. It will be brought on by companies that don't look like the traditional utilities look today.

It's easy enough to talk about one, two, or three percent growth rates. But until we translate these percent growth rates into gigawatts and dollars, we cannot really understand the implications.

With a one percent growth rate of electrical demand between now and the year 2000, the U.S. would require an additional 113 gigawatts of capacity, all else being equal. If capacity came in at a cost of $1,000 an installed KW, about the cost of a good coal plant today, the total cost would be about $113 billion. If capacity cost $2,000 an installed KW, the cost figure would rise to almost $250 billion, a quarter of a trillion dollars. At a two percent growth rate, we would need almost 240 gigawatts; at a three percent growth rate, almost 370. At $2,000 an installed KW, the total cost of capacity at these respective growth rates would be almost a half a trillion and three quarters of a trillion dollars. (See Figure 3)

The effect on the capital market of this range of numbers would be staggering. Holding the size of the corporate capital market constant, assuming that capacity would be financed on a slightly more leveraged basis than it is currently, and assuming that the capacity could be physically constructed within a five-year time frame, the results clearly show that something has to give.

At a one percent growth rate and a cost of $1,000 an installed KW, the utility industry would have to borrow about $14 billion each year for the five-year construction phase, taking up about 17 percent of corporate capital market. At a 2 percent growth rate and a $1,000 cost, the numbers would rise to $28 billion borrowed and a tap of 35 percent on the corporate capital market. A three percent growth rate would increase the borrowing to $44 billion dollars each year or 55 percent of the market.

To put these numbers into perspective, the year in which the utility industry borrowed the most it ever had was 1982: $15.5 billion dollars. The year in which it took up the largest share of
the corporate capital market was 1981; 25 percent.

At a $2,000 an installed KW cost, the numbers become bizarre. The industry would take up 33 percent of the market to finance a one percent growth rate, 70 percent to finance a 2 percent growth rate and 100 percent plus to finance a three percent growth rate.

Obviously, this cannot happen, and it won’t happen because all relevant marketplaces—for load technology and the market will adjust well before we get there.

The point I want to make is that we cannot afford to allow ourselves to think that we can just let things go along as they are now in the blind faith that the U.S. will end up with a low cost, reliable, and adequate electrical supply in the future.

There are a couple of important danger signals to keep a watch on. The first is the rate of capacity additions which will drop dramatically after 1988. New orders have averaged only 1.2 gigawatts per year over the last 4 years. While there is much fanfare on wall street that utilities are now “cash cows” being “over the hump” of construction, we should ask whether or not this is only a lull before the next storm. (See Figure 4)

Before we can answer that question, we have to look at the other moving pieces in the capacity equation which are increasing in number as well as in their uncertainties.

The supply equation has several parts to it. It starts with grand scale central stations and small gas turbines under traditional regulation. Added to that are gigawatts from plant extensions, conservation and negawatts, self and cogeneration, imports, micro cogeneration and, perhaps, eventually even the “pg.” (That’s the “personal generator,” a little gizmo that sits next to your PC and supplies electricity for a room.)

Subtracted from those are gigawatts lost from retirements due to old age and to un-economic fuels.

The Electric Power Research Institute (EPRI) has made estimates of how many gigawatts can be added to the system and how many might be lost from the system. Using a 50 percent probability level for each of these supply strategies, EPRI’s estimate would be that we will gain about 100 gigawatts and lose about...
150 between now and the year 2000. In other words, there’s a 50 percent probability that we will lose more capacity than we will gain from these strategies. (See Figure 5).

![Diagram](image)

**Figure 5.**

Of most concern to me about EPRI’s numbers is the uncertainty surrounding them. For example, EPRI estimates that there is an 80 percent probability that the loss of gigawatts due to retirements due to old age is somewhere between 65 and 325 gigawatts. The difference is 260 gigawatts, 261,000 megawatt plants. At $1,000 an installed KW, the difference alone represents over a quarter of a trillion dollars. We truly have a crap shoot here.

Another danger signal is the aging of U.S. capacity. In 1965, the average age of U.S. electric plant was 13 years. In 1985 it was 18. It has been estimated that by 1995 the average age of U.S. electric plant will be 30 years. The fleet may be going obsolete all at one time. (See Figure 6)

I would like to turn back now to the issue of competition. I believe the genie is out of the bottle, and that it is here to stay.

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**DANGER SIGNALS**

**U.S. CAPACITY IS AGING FAST. ARE WE CREATING A PIG IN THE PYTHON FOR REPLACEMENTS AND FINANCINGS?**

It is easiest to understand what competition means to utilities if we look at it from the perspective of business strategy using a matrix. On one axis there are high or low barriers to entry, in our industry called a franchise. On the other axis there are high or low barriers to exit, in our industry called an obligation to serve. (See Figure 7).

Utilities have historically been in the high-high quadrant, a good place to be, characterized by low risk, very stable returns. When competitors are allowed to enter, many of them with infant industry subsidies under PURPA or through industrial bypass, utilities are moved to the very worst quadrant—that with low barriers to entry but high barriers to exit.

Competitors are in a good strategic position relative to utilities because they have low barriers to exit. They may or they may not be there over time.

Once again, we have an asymmetry. This one required that we raise the question of what is fair competition, or what some call the “level playing field.” I am particularly fond of Edith Miller’s
FROM PERSPECTIVE OF BUSINESS STRATEGY, UTILITIES ARE BEING MOVED FROM LOW RISK, STABLE RETURNS TO HI RISK, LOW RETURNS.

<table>
<thead>
<tr>
<th>LOW</th>
<th>BARRIERS TO EXIT</th>
<th>HI (OBLIGATION TO SERVE)</th>
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<td>ENTRANTS (MINIFANT INDUSTRY SUBSIDIES &amp; CREAMERS)</td>
<td>UTILITIES IN 80's + (UNDER MISH MASH: &quot;REGULATED COMPETITION&quot;)</td>
<td>TO</td>
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<tr>
<td>LOW</td>
<td>GOOD</td>
<td>WORST</td>
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<tr>
<td>BARRIERS TO ENTRY</td>
<td>UTILITIES (UNDER TRADITIONAL REGULATION)</td>
<td>FROM</td>
</tr>
<tr>
<td>HI (FRANCHISE)</td>
<td>BEST</td>
<td>GOOD</td>
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</tbody>
</table>

Figure 7.

takes on a Goliath in a vulnerable market niche.

I believe that competition is a force for innovation and productivity and progress. It is not, however, the objective in itself. The objective is finding the most effective route to the desired end result: an equitable society, a more efficient allocation of our economic resources, and a more productive U.S. electrical system.

The raw fact of the matter, however, is that under competition there will be winners, and there will be losers. Winner companies will be those that become low cost producers. The losers will be high cost producers. There isn't a whole lot else to say about that because kilowatts are, after all, a true commodity, at least at the wholesale level.

As for investors, the winners will have all of their assets earning. The losers will be those who have unearning or underearning assets.

As for regulators, the winners will be those who deliver stable rates and healthy companies over time. Losers will be those with erratic rates and unhealthy companies.

The conclusion to be drawn from this scoreboard is very clear: the industry as a whole must shift from a "cost plus" to a "cost minus" mentality fast.

The industry, in essence, is now at a swing point between Marx or Milton. (See Figure 8). If you think of regulation and competitions being at opposite ends of a continuum, at the extreme right is the University of Chicago and the free marketers. At the extreme left are the Marxists.

These two otherwise totally diverse schools of economic thought agree on only one premise: regulation is undesirable and should be scrapped. They disagree, however, on what should replace it. Milton Friedman would say it should be replaced with complete laissez-faire, shark infested waters. The Marxists would say it should be replaced by state ownership.

If we have been in a state of regulatory equilibrium for the last 20 years or so, the pendulum has now started to move toward deregulation. Transmission access is the issue that will drive the speed of the pendulum's swing. If we don't manage that issue properly, we are likely to see a swing back, towards the left, towards re-regulation and perhaps even more state ownership.

For all of us—regulators, companies, customers—the overarching principle is, of course, the mutuality of our needs as we
WE ARE AT A SWING POINT: MARX OR MILTON?

REGULATION / COMPETITION

MADRISTS

SCRAP REGULATION
STATE OWNERSHIP

U. CHICAGO

SCRAP REGULATION
MARKET FEEDING FRENZY

RE-
REGULATION

TRANSMISSION ACCESS WILL DRIVE THE SWING,
EITHER WAY, REGULATION AS WE KNOW IT
WILL BE GONE.

DE-
REGULATION

Figure 8.

try to pursue our common purpose, which is a vigorous economy and an equitable society. Unfortunately, we often lose sight of our shared purpose and our shared principles as we grope our way about the confusing transition from regulation to competition in which we find ourselves.

We must take the time to ask what are the shared objectives today. We must take time to figure out the best decision criteria and the fairest rules under which we can protect those customers who do not have choices and under which we can allow competition to emerge to benefit customers who can exercise choices.

Under imperfect regulation, rates are set by government agencies, based on cost of service. Under imperfect competition, prices are set by markets, based on value.

But our current world is not either/or; it is both. Customers are now accruing market power at differing rates. Some are now able to exercise choice and market clout, while others are not. Large customers who have options today are having their prices set by markets while rates for captive customers are still being set by regulatory commissions. This is the heart of the transition issue of how to serve two masters, how to manage the mishmash. We can make up clever names for it—"regulated competition" or "partial deregulation," but it is still a mishmash.

The radical question that must be asked and answered is whether regulation and competition can co-exist in the same firm over time. I think the answer is that they cannot. If I'm right, industry restructuring is a certainty.

During the transition from regulation to competition, the action in the commissions is going to shift away from rate cases and revenue requirements. Our new intellectual, policy, and management challenges will focus on an array of knotty rate design issues. For customers who have options, the issues will include rate menus, reservation fees, prodigal rights, stand by charges, and wheeling—all related to market stimulation. For customers who do not have options now, the issues will include core pricing, rate contracts, time of decade rates—all related to market simulation and protection of captive customers from any adverse effects of competition.

Whether, and under what rules and corporate structure, a CEO will be game enough in the future to invest billions of his stockholders' and bondholders' money in the future will depend on his "CQ"—his cynicism quotient.

He has a high CQ if he believes in the "lesser-of-regulation." By that I mean the weighting of the dice by the regulators so that the utilities can never win. This comes about because of the front-end loading of ratebase under traditional cost of service ratemaking.

When a plant first comes into service under traditional ratemaking, it is put into ratebase at its full book cost. Because it depreciates over time, its asset value decreases over time. Its economic value, however, does just the opposite: starting at less than book value, it increases over time. (See Figure 9). A key analysis in investment decisions is, of course, the probable slope of the economic value curve, which will depend on several unknowable but predictable factors.

"Lesser-of-regulation" means that regulators will set rates on the lesser of market value or book value. When the market value is low relative to book value, there will be much talk of competition, deregulation, and value-based pricing. When, however, we reach a
KEY FACTOR IN INVESTMENT DECISIONS IS THE CYNICISM QUOTIENT (CQ)

Figure 9.

crossover point in the future and book value is lower than market value, then the regulators will switch back again to cost-based rates with much talk about the need for re-regulation.

As long as an electric utility stays fully integrated and regulated, it will, I believe, be subject to "lesser-of-regulation." Promises to pay in the future issued by regulators today may not be bankable. FASB 71, incidentally, is telling us that FASB has a high CQ because of the uncertainty surrounding those promises to pay in the future when the market value of the plant exceeds its book value.

Recognition of the likelihood of "lesser-of-regulation" will be another driving force in the restructuring of the industry. The industry will, as a result start to disaggregate into stand alone "Gencos, "Transcos," and "Discos."

I believe that we will see much more diversity among individual companies, especially in the business strategies. We will also see different types of asset ownership. And there will be mergers and acquisitions, and spin-offs, and spin-outs, and a few spit-ups
THE FRAGMENTED UTILITY INDUSTRY: AN OXIMORON AND/OR THE TARGET OF OPPORTUNITIES?

<table>
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<tr>
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<td>8,001+</td>
<td>104</td>
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52% OF THE COMPANIES OWN 14% OF THE CAPACITY.
17% OF THE COMPANIES OWN 61% OF THE CAPACITY.

Figure 10.

ity. These data say to me that there is a lot of potential for consolidation through mergers and acquisitions among the 144 small and medium-sized companies that own less than 4,000 megawatts.

An important question for utility boards of directors and for utility regulators is who will be carrying out the restructuring of the industry. Will it be the raiders or will it be leaders from within the industry? Will Boone Pickens or Carl Icahn or Bob Bass eat the seed corn or plant the seed corn of this industry whose product is so absolutely critical to the health of the national economy?

So to summarize, the question was "Can an electric utility serve two masters: regulators and markets?" My answer is no. But I believe that both masters can be well served and satisfied, and this is why.

I think that excess capacity and cost overruns and prudence audits have turned the generation and supply issues into a capacity crap shoot. As a result, utilities that stay vertically integrated and fully regulated by both Federal and State Commissions will be subject to the "lesser of regulation" phenomenon for both old plant as well as new plant. The weak will get weaker, and the strong will get weaker too. Utilities that separate distribution from generation will have the best shot at the future.

Traditional regulation will have to sharpen its focus on the end results for the captive customer as we move towards the disaggregation of the industry into separate Gencos and Transcos and Discos. The motto should be the minimum regulation necessary to protect captive customers, not the maximum possible to substitute for and second guess management.

I see an electric utility future in which: 1) generation and distribution will vertically disaggregate and horizontally consolidate; 2) gencos will deregulate over time and become highly competitive commodity businesses; 3) transcos will operate as common carriers with the Department of Justice as the antitrust watchdog; 4) discos will stay regulated on behalf of the remaining franchise customers retaining an obligation to serve under some sort of a more clearly defined and more legally binding social contract; 5) individual contract customers will exercise their competitive choices at an increasing pace; 6) groups of captive customers will organize themselves in inventive ways to become contract customers; and 7) discos will eventually evolve out of business over time as the personal generator becomes technologically viable and economically feasible.

I encourage all of you to remember that old Chinese curse: "May you live in interesting times." Electric utilities are clearly living in very interesting times. But as this Chinese curse says much about where we are right now, three Chinese characters say much about the future.

The literal translation of the Chinese characters for customer is "guest of great consideration." The literal translation of the Chinese character for technology is "ingenious technique." The literal translation of the Chinese character for crisis is "dangerous opportunity."

Success in the future for electric utilities will depend heavily on their ability to recognize customers as guest: who can come and go, and on their determination to treat their guests with the greatest consideration.

Success will also depend on their cleverness and thoroughness and unrelenting drive to apply new ingenious techniques to absolutely every part of the business.
With these two new factors for success on the horizon, the electric utility industry and its regulators should be able to see the future as a “dangerous opportunity,” as the Chinese would say. It demands our attention, our creativity, and our leadership if we are to find and grasp the opportunities amidst all the dangers.

Building on the Louisiana Decision

Gail Garfield Schwartz, Ph.D.

The Supreme Court’s decision in Louisiana v. FCC was on the surface about a mundane matter: methods of depreciating telephone equipment for ratemaking purposes. But the ramifications of the decision are far reaching in terms of future attempts by the FCC to preempt the states. The potential for preemption has been markedly curtailed, thus giving states a much needed opportunity to address the challenges of regulation in a partly competitive, partly monopoly industry. It remains to be seen how rapidly and how creatively states will seize the opportunity.

Note: The author is indebted to Lawrence Malone, New York Public Service Department Counsel, for preparing the legal history and interpretations presented herein. The policy implications are her sole responsibility.
The Case Itself

The Supreme Court’s depreciation decision followed a decade of FCC incursions into what previously had been considered the states’ portion of the telecommunications arena. These forays represented a departure from historical precedent dating from before the Communications Act of 1934 and extending for some forty years thereafter. The act, which created the FCC, conveyed limited telecommunications responsibilities to the Federal Communications Commission, reflecting the fact that state regulatory commissions had been regulating the telecommunications industry for more than twenty years. Since ninety-eight percent of telephone traffic was intrastate, it was generally recognized that the states were most familiar with the technical principles and criteria upon which regulation depends. The federal government concentrated on regulating toll service and joined with the states in settling most questions involving dual jurisdiction, through the joint board negotiations.

Interconnection

The first major challenge of the FCC to the established system of dual regulation came in 1968, when the FCC broke new ground with its Carterfone decision, allowing customers to connect telephone sets of independent vendors to the network. This decision reflected the condition of real competition in the provision of telephone customer premises equipment (CPE), which if encouraged would clearly benefit ratepayers by reducing the lifetime cost of such equipment substantially. Most states followed suit; some, including New York, even outlawed the FCC by creating innovative rate structures designed to encourage competition. A few states, however, did not agree with the new policy and, by opposing interconnection frustrated the FCC’s action.

Therefore, in 1975, the FCC ordered states to permit interconnection. In 1976 the order was upheld by the 4th Circuit Court of Appeals on the ground that it was justified to implement the FCC’s new policy, and review was denied by the Supreme Court. The FCC acted as if it had received carte blanche to invade regulatory territories previously reserved to the states. As favorable lower court decisions piled up, the FCC was allowed larger portions of the states’ jurisdiction on a theory that control of these areas was needed to further its general policies.

One particularly notable case was a 1982 D.C. Circuit Court of Appeals decision known as Computer II. It upheld an FCC opinion deregulating CPE and preempting the states’ regulation of new telephone equipment. The basis for the court’s action was an FCC finding that preemption was necessary in order to avoid a frustration of its program to deregulate CPE.

Depreciation—4th Circuit

One year after Computer II, the FCC, flush with victory, took a giant step into regulation of the turf perhaps most sacred to the states, direct calculation of the intrastate revenue requirement. It declared that its own rules of depreciating telephone plant and equipment were to apply to the intrastate as well as the interstate ratepayers. The FCC rules involved shorter depreciation periods and different treatment of categories of equipment (equal life, rather than vintage group), with the result that the companies could recover their investment in a shorter time than had hitherto been possible either under FCC rules or under the rules of most states.

From the states’ perspective, then, there were two issues involved, one jurisdictional and one economic—and by implication political. If the FCC prevailed, then state regulators would have to raise rates faster to cover the increased depreciation costs. The FCC would not bear the political consequences for rate shock—state regulators would.

To the states’ dismay, the FCC’s depreciation decision was upheld by the 4th Circuit Court of Appeals, which found that preemption was lawful because it was needed to further the FCC’s general policy of maintaining an efficient interstate network.

Supreme Court Issues

When the states asked the Supreme Court to review the case, the threshold issue before the court was whether this depreciation case was worth hearing. In arguing against the appeal, the FCC, AT&T, and GTE argued that the preemption war was over. The states answered that the depreciation order should be reviewed because it invaded the sanctity of local revenue matters, which Congress had expressly ruled off limits to the FCC. And they warned that if the 4th Circuit decision was upheld, the FCC would soon do away with dual regulation by taking over all meaningful
elements of state regulation. For the first time, the Supreme Court granted *certiorari* in a FCC preemption case.

At stake were two issues: (1) statutory construction, or to whom Congress intended to give intrastate depreciation and accounting jurisdiction, and (2) if the FCC lacked specific statutory authority to set local depreciation charges and accounting classifications, whether it nonetheless could preempt the states to avoid a frustration of its general policy of maintaining an efficient interstate network. The Supreme Court found not only that the FCC lacked power over local depreciation charges, but also that Section 152(b) of the Communications Act expressly reserved intrastate depreciation and accounting matters to the states. It agreed with the states that Section 152(b) was a jurisdictional overlay to the act and that, notwithstanding the FCC's contentions about Section 220 (a provision dealing with depreciation charges), intrastate charges, classifications, practices, services, facilities, and regulations were matters which Congress clearly intended the states to regulate.

Thus, as to possible FCC preemption for policy purposes, the Court held that if dual regulation frustrated the FCC's implementation of its general policies, the FCC could either accept this frustration, or redefine its policies, or make its case to Congress for a new law.

**Effect on Plant Replacement**

The suggestion has been made that the Supreme Court's decision is legally sound but contrary to the public interest because it endangers the telephone companies' ability to replace plant in a timely fashion. This view illustrates a common misunderstanding of the difference between accounting and the basis for investment decisions. The fact is that a decision to replace plant turns on factors such as financial viability, the cost of replacement (including interest charges), and the operational advantages of new plant versus old. Should regulators doubt this, they have only to refer to a telephone company's instructions to its own personnel. As AT&T's publication *Engineering Economy* explicitly states, the notion that accelerated depreciation charges are essential to encourage plant modernization is a "mistaken concept of depreciation." That the text rightly explains, is a sunk expense which should be ignored when deciding on modernization or plant replacement, a decision that turns on considerations of the future. In the list of considerations affecting viability of investment decisions, depreciation is but one of many.

Does the Supreme Court decision tell us whether states and the FCC set adequate depreciation rates in the past? Not really. There is no question that we have a reserve deficiency, but it is nowhere near the size alleged by the industry in *Louisiana v. FCC*. Many states are amortizing the deficiency in future depreciation charges, or adopting remaining life accounting.

Not all regulators are happy with this approach. Indeed, some suggest that companies want to depreciate plant and equipment while "abandoning" it, thus causing ratepayers to pay for new plant as well as they also pay down the old equipment, which still has a long functional life. Again, the point is that depreciation and new investment are not linked decisions. If a piece of equipment still has a long, efficient functional life, it should not be replaced, period—and the degree to which it has been depreciated has nothing to do with the replacement decision. Conversely, if the item's functional life is virtually over, it should be replaced, even if it has been depreciated very little. Regulators looking at company construction and replacement plans should look at functionality and expected break-down rates, not at accounting practices.

**Using the Depreciation Power for Innovative Regulatory Purposes**

There is one reason to look carefully at accounting practices, however, and that is with regard to the necessity for new equipment for monopoly service. This is where the challenge and the opportunities lie.

A good argument can be made that nearly all the plant needed to provide plain old telephone service is in place, and that most new capital investment will be needed primarily to provide enhanced services that will eventually be competitive. Regulators must be aware of this possibility to prevent regulated companies from gold-plating the system. Even now, some economists believe electronic switches are being installed where they are not needed, thus driving up NTS costs that are to be recovered in carrier access charges and/or subscriber line charges. Only minimal nec-
However, from another perspective, footnote 4 suggests that if there is a direct conflict between a state regulatory activity that arguably falls within Section 152(b) and the FCC's execution of a clear-cut duty specifically enunciated in another provision of the Communications Act, the Court may read the state activity in question out of Section 152(b). In other words, we have to assume for purposes of statutory construction that Congress was logical, and it would be illogical to entrust the FCC with a specific statutory responsibility that it would not be able to execute due to the states' own execution of a responsibility under Section 152(b).

The way to reconcile such a conflict would be to read Section 152(b) as not preserving to the states the regulatory power which would totally negate the execution of the specific FCC responsibility. Section 152(b) is a fairly clear-cut statute, which cannot be overridden by general FCC policies or general statutes, such as Section 151. The only way to break the Section 152(b) wall is to point to a specific FCC duty that is being absolutely frustrated by the states' powers under Section 152(b).

Lawyers seeking to determine the effect of the Supreme Court decision ask whether an auxiliary power, that is, a responsibility that can be regarded as a logical extension of a specific statutory duty, would break down the Section 152(b) wall. The attorney who argued the case before the Supreme Court for the states, Larry Malone, thinks the answer will have to turn on each case. In other words, we will have to wait and see.

Still, we can hazard some guesses as to the effect on pending cases and FCC issues. The FCC in mid-November 1986 granted New York State an exception to the FCC plan to deregulate inside wire. In part the FCC action was based on a presentation of the New York Department of Public Service staff regarding the possibility of the state itself gradually deregulating, without need to recover lost revenues from basic rates. From New York's perspective, therefore, the need to test the FCC's preemptive authority over the deregulation of inside wires should not arise. But it seems apparent that, if tested, it would come under the umbrella of the Louisiana decision. The FCC is under no affirmative obligation pursuant to the Communications Act to deregulate inside wire. Rather, deregulation is seen by the FCC as a way of furthering its general policy goals of promoting a competitive and efficient national telecommunications network. Some states may agree with

Ramifications of the Decision

The depreciation victory for the states makes it quite clear that the FCC's general purpose of maintaining an efficient interstate telephone network cannot be used as a lever to preempt specific intrastate functions reserved to the states by Section 152. And since Section 152 controls the rest of the Communications Act, and carefully preserves intrastate regulation for the states, we expect that even if specific FCC purposes (as opposed to statutory functions) are being frustrated by dual regulation, preemption will not be allowed.

If there is a conflict between an activity over which the FCC has specific jurisdiction and a state activity arguably set forth in Section 152(b), can the states be preempted? One view is that the jurisdiction afforded the states in Section 152(b) over intrastate charges, classifications, practices, services, facilities, and regulations appears to be unconditional; 152(b) tells us that none of these activities are subject to federal preemption. Furthermore, the Supreme Court in Louisiana does not appear to read any conditions into Section 152(b).
the FCC, while others may not, or may see other means to accomplishing these ends in their own telecommunications markets. But the Supreme Court seems to have made clear that in such situations the states are entitled to make these decisions for their own intrastate market. Where it is not a question of specific affirmative obligations of the FCC being frustrated, but simply a difference between the FCC and a state over policy judgments, the FCC, by virtue of Section 152(b), may not preempt. Thus, the states can legitimately say to the FCC: Deregulate your portion, but we will retain jurisdiction over our portion, and you accomplish your goals as best you can under the circumstances.

Moreover, on a policy level, it makes sense for the states to retain regulatory authority with respect to inside wire. Thus, while some customers now own their own inside wire, others, either by choice or because of practical necessity, continue to rely on inside wire provided by the local telephone companies. The states must retain jurisdiction over the provision of this inside wire in order to ensure that these customers are not being overcharged and that the quality of the facilities being provided by the company is maintained.

Another key issue will be FCC authority to override the states’ regulation of the entry of new carriers. The Louisiana decision seems to preclude that authority. The D.C. Circuit Court has ruled that the FCC cannot prevent states from regulating the entry of radio common carriers, citing Louisiana. How states use power over entry and exit may in the long run be even more important than the depreciation rules and accounting categories they choose to adopt.

In the first place, they can ensure that entry takes place only under conditions of relatively stable competitive opportunity—not under artificially created opportunities such as premium access, which, when eliminated, will vastly alter the competitive cost picture. This will prevent customers from being stranded without service in the future.

In the second place, they can by their degree of regulatory oversight encourage or discourage competitive services, and not always in the expected ways. For example, if telephone companies are not required by the states to stand by to provide telephone service to customers opting for shared tenant services, then shared tenant services might be less attractive to customers. There are many other elements of entry regulation that affect the economics of competition, and it is time to sit down and think them all through.

The end of the Louisiana story, therefore, is that while telephone companies today may gravitate toward the FCC’s preemptive position, they may soon find themselves hamstringed by that very posture. Telecommunications is no longer a unitary industry but is, rather, a fragmented industry serving many market segments. Voice transmission over the existing network is now a large part of that industry, but in future it will certainly be a smaller proportion, even if still a large generator of income. Telephone companies, which now are free to compete in their permitted lines of business in one another’s territory, will enter new geographical markets as well as new lines of business. States that regulate with one eye toward the economic development potential of telecommunications growth and the other eye toward POTs rate stability will be in the best position to help ratepayers in both the long and short run. By harnessing market forces to the ratepayers’ interest, both ratepayers and companies will benefit.
Comments

Preston C. Shannon

This session’s topic is very timely. The calls for a change in the traditional form of ratebase, rate-of-return regulation have intensified because of the increasingly competitive nature of our utility industries, especially telecommunications. However, many of the problems cited concerning our regulatory process, such as the inability to provide proper incentives for efficiency or innovation, have been voiced for many years.

It is healthy to reevaluate our methods of regulation. There has been little change in our regulatory approach but great changes within the industries we regulate. The four papers that have been presented offer much food for thought. I will comment on them in the order in which they were presented.

“Options for Modifying Rate Base Regulation” by Robert J. Keegan and Paul F. Levy

Commissioners Keegan and Levy begin with an overview of the economics of regulation and the structural changes caused by competition in the electric, gas, and telecommunications industries. Their comments and observations provide an excellent introduction for our session. I essentially agree with everything they say. It is particularly important to point out, as they have, that no single regulatory modification will be appropriate for all regulated industries. The varying degrees of competition must be considered.

I also agree with the conclusion that “competition has been stimulated more by economically inefficient pricing decisions made by industry and regulators than by inherent deficiencies in the ratebase regulatory model." For instance, within the telecommunications industry, high profit margins on long distance service encouraged new entrants. The profit margins together with new technology brought us to where we are now: a certain amount of competition, inefficient pricing, and a dilemma as to where to move next.

Four alternatives for modifying ratebase regulation are presented. The first alternative, the contribution model, would allow a utility to vary its prices to its customers that have competitive options, but the price would still cover variable costs. In Virginia we have used such a contribution model for interruptible gas customers. If a gas company were to lose its entire interruptible load to oil there would be an automatic shifting of significant nongas costs to the firm customers. The floor of the flexible rates we have established is based on the highest commodity cost of gas to the utility unless that utility can show that something less than the highest commodity cost is necessary to compete with alternative fuels and that the core customers will still receive a net benefit from retaining the interruptible sale at the lower price. The obvious advantage to this flexible rate system is the ability to respond rapidly to changing market conditions. The contribution model is not a "cure all," however, and in Virginia it is viewed as an interim step in our adaptation to the rapidly changing gas industry.

A second alternative to ratebase regulation is the social contract model. The social contract appears to be a deregulation of
certain services by the imposition of artificial constraints which have no relationship to the cost of providing service. The Virginia commission previously experimented with the use of a change in the CPI as a measure for limiting utility “make whole” rate increases. This approach was ultimately discarded because basing price changes on an index could result in excess returns or losses depending on the utility’s change in expenses as they relate to changes in the index. The social contract model may result in contrary price signals whenever there are unexpected changes in cost structures.

The surrogate market price model, or net-back pricing, is similar to the flexible rates for Virginia’s interruptible gas customers that I have already described. If this approach is used, certain constraints need to be set. The industrial customers should pay a price that reflects their cost of service or even the core customers could eventually be driven away. All customers are elastic to a certain extent; it is very difficult to determine the extent of that elasticity, however. Would net-back pricing for gas customers be used when the price of oil is at a high level? If so, what is done with the increased profits? As the authors state, if sufficient competition should become evident, the surrogate market pricing may be acceptable, but with constraints.

The fourth alternative to ratebase regulation that is discussed is full deregulation. There still does not appear to be adequate competition on the local level to justify full deregulation of the telecommunications, electric, or gas industries. The sudden shift to full deregulation would be an economic experiment. I am not anxious for the ratepayers of Virginia to be guinea pigs in an economic experiment.

Commissioners Heegan and Levy conclude that further structural changes are needed before some of the alternatives to ratebase regulation that have been proposed become feasible. In the meantime they feel that regulators should continue to disaggregate services and unbundle rates. I agree with their thoughts. We do not want to change hurriedly our regulatory process until we can assess the potential effects on the utilities and their customers. The telecommunications industry has made the greatest amount of competitive activity thus far, did to the rapid technological advances. I have set up a task force to study the Virginia telecommunications industry and whether we should change our method of regulation on an experimental basis. The task force will have representatives from the commission staff, the major telephone companies, and the Virginia Attorney General’s Office. They have been directed to determine (1) the nature and scope of competition today; (2) whether ratebase regulation inhibits local exchange companies from competing; (3) whether ratebase regulation provides incentives for modernization; (4) what alternatives are available; and (5) the benefits and drawbacks of any proposed change. I am sure that legislative changes will be required to vest the commission with the necessary discretion to put into effect any changes in our method of regulating local exchange carriers. Quality of service regulation will probably be with us for some time to come. We are not likely to relinquish this oversight responsibility until there are a lot of choices.

They write strongly that any drastic changes in regulatory approach should be examined thoroughly and receive input from all parties involved. We do not want change for change’s sake. A new approach to regulation should be designed to provide economically efficient pricing and proper incentives. Each industry should be examined independently so that the characteristics and competitive activity of that industry can be considered.

"Getting From Dominance to Competition: Criteria for Effective Deregulation" by William G. Shepherd

Unlike the first paper reviewed, Shepherd’s paper dwells on theory rather than reality. He places a great emphasis on determining a utility’s market share before deciding if there is an appropriate level of competition for deregulation. The use of market share as a sole determinant of market power is incorrect. He admits that "defining the markets and determining the market shares may be difficult in some cases." Market shares are derived from calculations that are frequently imprecise and usually vary in measurement from company to company. With the long distance telecommunications market, should market share be based upon number of calls, minutes of use, number of customer revenues, or some other criteria? A market share at a given time is not the important measure. It is the trend over time in a consistently calculated market share that provides relevant information.
Shepherd feels that if a company has a market share of more than 40 percent there can be no effective competition. If regulators were to use this rule of thumb, there would never be deregulation. Virginia was the first state to deregulate the interstate, inter-LATA toll market. When this decision was made it was felt that it would be unfair to regulate AT&T and allow its competitors to operate in a competitive environment. Certainly, AT&T had a market share of more than 40 percent no matter what criteria would be selected for comparison. Although the term "level playing field" has become a cliche, the concept is still valid. In the 1970s it was claimed that IBM was so dominant it would drive competitors out of the market. We know what has evolved in the computer industry. By rejecting the dominant firm theory the Virginia commission placed AT&T and the other common carriers on the same footing and encouraged a competitive market in the true sense. We did, however, set certain restrictions. AT&T would still be the carrier of last resort for those rural areas that have no competitive activity. AT&T would not be able to deaverage rates. All the long distance providers were mandated to provide quarterly data which would be used to monitor the progress of competition. The data submitted include price changes, new offerings, exchanges served, minutes of use, number of calls, revenues, and other items. If the commission should perceive that AT&T has been able to use market dominance to drive out competitors, the threat of reregulation hangs over its head.

Shepherd does not recognize the effects that the threat of future competitors can have upon an industry. One of Virginia's electric utilities was having a difficult time negotiating favorable rail rates for the transportation of coal. The utility was one of the prime lobbyists in the state for the legislative approval needed for the development of a coal slurry pipeline that could be used to bypass the rail system. Before the pipeline issue came to a vote the utility was offered a long-term rail contract at a good rate. The threat of competition from the coal slurry pipeline apparently had an effect on the pricing decision of the rail road company. This same threat of competition is inherent in a market where the barriers to entry have been removed. The threat will not directly affect market shares, but it will affect pricing.

Shepherd feels that if a firm has more than 40 percent of the market share it should continue to bear the burden of service re-

spendability. Although I cannot agree with a specific market share number, I do agree that the regulation of service responsibility and service quality will be with us for some time to come. There is a tremendous conflict between the elimination of subsidies inherent in the telecommunications industry and the concept of universal service.

State commissions cannot rush into deregulation. They must consider the short-term and long-term needs of all the parties involved. It is the core customers, the residential and small business users, who will need protection. Shepherd and I seem to agree on this issue. In making the decision to deregulate, however, Shepherd would concentrate on market shares. I feel that the decision should be based upon whether (1) true competitors and the threat of competition would emerge, (2) competition would be broadly based or limited to the most profitable markets, and (3) it is truly in the public interest. The conclusion that can be drawn from the deregulation of the telecommunications industry to this point is that there is no rational transition from a monopoly to competition. There is no perfect answer. We must try for the least painful and most logical approach.

"Serving Two Masters" by Joellyn K. Murphy

Murphy has presented an entertaining and thought-provoking paper. I disagree with her pessimistic view that regulation had led us to the brink of disaster and must be scrapped for our salvation. I do agree that both regulators and the electric industry have made many past mistakes and need to work together toward their common goals.

There is no doubt that prudency audits, write-offs, allowances, and phase-ins have caused utilities in some jurisdictions to be reluctant to commit funds to future generating capacity. Those extreme reactions by regulators must be examined on a case-by-case basis, however, to determine if the utilities were undeserving of such treatment. The electric utilities and state commissions need to make joint commitments to the building of capacity.

In Virginia, all capacity additions above 100 mw must be approved in advance. The approval process will allow the commission to examine the load forecast, construction design, financing plans, and other aspects of the decision to construct. If approval is granted,
it would be very difficult for a future prudency audit of the decision to build rather than secure power from another source. Obviously, there could still be imprudent construction practices, which were the cause of many of the previously mentioned disallowances. We do, however, have in place a construction monitoring program which should help prevent construction problems from getting out of hand. I feel that such a sharing of the risk between the utility and the state commissions is only fair.

I am just as concerned as Murphy about the increasing average age of our country’s electric generating capacity. In addition, we have no historic perspective of how long nuclear plants will be able to operate. Our nuclear plants have to be operating as safely and efficiently on the last day of use as on the first day of use. I do not feel that the absence of regulation will make the problem of aging capacity any easier to deal with. The utility must make maximum use of new technologies, improve operating efficiencies, make strides in cost cutting measures, and place a strong emphasis on planning. Both demand side and supply side techniques must be developed and refined.

The use of cogeneration facilities will be an important factor in the success of electric utilities’ future plans. The state regulators must be sure that the cogenerators are paid a proper price for their power. We are interested in cogeneration. If developed properly, the electric utilities should welcome cogeneration.

Murphy claims that utilities are faced with a problem because plants are depreciated and decline in rate base value as the economic value of the plant is increasing. The large levels of annual depreciation within the electric utility industry are a major source of its tremendous amount of cash flow. Perhaps what Murphy should advocate is the use of this cash flow for future capacity rather than for the diversification which has become so popular.

Although there may be mergers and consolidations within the electric industry I do not feel there will be much takeover activity. It is true that takeover artists may covet the strong cash flows of utilities, but I cannot picture a Boone Pickens type of corporate raider being able to adjust to operating a regulated company. The companies that have been subject to takeover rubouts, Public Service of Indiana, are troubled utilities selling at less than book value. Many of the electricity already have in place “shark repellent” measures to further hinder unwarranted takeovers. I do foresee more joint ventures between utilities for future base-load generation.

I agree with Murphy that transmission access is a critical issue to the future shape of our electric industry. However, even assuming open access to the transmission system I do not think we have the grid in place to be transporting massive amounts of power to all parts of the country. It would take a major commitment of time and capital to improve the electric grid so that the highly competitive generating business envisioned by Murphy, with several massive generating companies, would be able to operate. With such a system we would drastically increase our vulnerability because of our dependence on large transmission lines to provide power for distant localities. Interruptions caused by weather, overload, or even terrorists could be devastating.

The electric industry has been easier to regulate than other forms (acid rain, nuclear problems, unstable oil prices) I feel that smaller, more diverse units must be considered by electric companies. As previously mentioned, demand side options must be thoroughly evaluated. The industry has no choice but to reevaluate its options and concentrate on long-term planning to minimize the risk associated with bringing new capacity on line. The state commissions must recognize the problems faced by the electric industry and be willing to help them meet these risks.

The electric industry has been weathering escalating fuel costs, inflated financing costs, increased construction costs for new plants, uncertain demand trends, growth of nonutility generation, and the emergence of a bulk power market. Today in Virginia electric rates are stable, fuel expenses are lower, efficiencies of generating units have improved, service is reliable, and the stockholder wealth has increased. Where utility management has flexibility in meeting its challenges and responds rapidly to changing circumstances, two masters can be served. A small telephone company in Virginia has a motto all utilities should take to heart: “We must prosper to serve well and serve well to prosper.”

"Building on the Louisiana Decision" by Gail Garfield Schwartz

I have a particularly close personal interest in Commissioner Schwartz’s comments on the Louisiana decision. That is because this case could easily have gone down in history as the Virginia
decision. Our commission initiated the preemption battle in the Fourth Circuit Court of Appeals and lost in a split decision. Judge Widener cast the dissenting vote and clearly saw this issue in the proper perspective. In retrospect, we should have continued our fight. The important thing is that the states were ultimately upheld, and the FCC's long invasion into intrastate ratemaking was halted.

This invasion goes back at least to 1976. A chronology follows.

- **North Carolina Utilities Commission v. FCC** (1976 and 1977): The U.S. Fourth Circuit Court of Appeals upheld the FCC's position that subscribers could provide their own telephones and states could not prohibit subscribers to connect their own telephones.
- **FCC Memorandum Opinion and Order** (Released April 27, 1982, CC Docket 79-105): NARUC had petitioned the FCC for clarification of its 1981 Order requiring companies to begin expensing station connections. The FCC ruled that this order was not intended "to override state agency actions."
- **FCC Memorandum Opinion and Order** (Released January 6, 1983, CC Docket 79-105): AT&T had petitioned the FCC to reconsider its April 27, 1982, Order. The FCC reversed its position and said it does have authority to "preempt inconsistent state depreciation policies and rates."
- **Virginia State Corporation Commission v. FCC** (June 18, 1984): The U.S. Fourth Circuit Court of Appeals affirmed the FCC's preemption order.
- **Louisiana Public Service Commission v. FCC** (May 27, 1986): The U.S. Supreme Court reversed the Fourth Circuit Court's decision and, in effect, admitted Judge Widener's dissent.

In the Louisiana decision, the Supreme Court looked at Section 151 of the 1934 Communications Act, which directs the FCC to develop a rapid and efficient national telephone network. The Court said Section 151's broad language was expressly limited by Section 152(b), which says in part: "Nothing in the chapter shall be construed to apply or give the Commission jurisdiction with respect to (1) charges, classifications, practices, services, facilities or regulations for or in connection with intrastate communications service ... of any carrier (emphasis added)." This decision was reached despite the possibility of inconsistent state depreci-
preempt. However, if it is not communications service, how does the FCC have any authority at all? Does the FCC have preemptive authority over insurance regulation because it is not common carrier communications service?

Second, if inside wire is not considered common carrier communications service, then why are drop wire, outside plant cable, or, for that matter, central offices considered so? Any customer is free to construct a communications network and bypass the entire switched network just as customers are free to install inside wire.

Third, Paragraph 2(b)(1) of the Communications Act says the FCC does not have jurisdiction over intrastate “charges, classifications, practices, services, facilities, or regulations.” Nevertheless, Paragraph 37, p. 17 of the 224/86 order, discusses the impact this decision has on intrastate rates. Thus, the FCC acknowledges that this order affects intrastate ratemaking.

Fourth, inside wire is similar to customer premise equipment in one respect. That is interconnection. I believe the FCC can preempt to require states to allow customers to connect their own wire to the telephone system just as they can CPE. That is because interconnection is not separable. It would not be practical or economical to have two sets of inside wire or telephones—one for interstate and one for intrastate. (Inside wire interconnection has been allowed in Virginia for several years.) The similarity stops there, however. You do not have to deregulate inside wire to require interconnection. And you do not have to physically separate the wire to have intrastate regulation and interstate deregulation, or vice versa. That can be done by accounting and separation procedures just as is done for depreciation. Telephone plant duplication would not be necessary.

Fifth, the FCC’s inside wire decision is unfair. It orders revenues and expenses for installing and maintaining inside wire to be accounted for “below-the-line.” How ever, embedded inside wire investment (for wire installed and capitalized prior to 1981) remains “above-the-line” and in the telephone company ratebase. The amortization expense is, of course, still above the line. Thus, this expense has to be supported through local rates.

The FCC is, at the surface, doing a good job of regulating interstate long distance communications. That is, if you measure “good” in terms of interstate rate reductions. However, these reductions are almost exclusively being made at the expense of the local ratepayer. Most local customers are paying more for total communications service now than they were before long distance rates started dropping. Much of this is due either directly or indirectly to FCC actions. It is obvious their policies influence intrastate ratemaking. According to Congress, they should not. I trust the courts will once again come to this realization during the inside wire deliberations.
Part Two

Equal Access and Beyond – I
A Rational Direction and Design for Access

Alan R. Schriber

The discussion that follows is that from the perspective of a regulator. I will make a couple of assumptions that I think are critical. First, I want to assume that universal service is and will always be a social goal. In fact, this might be the "rational" point of view that is noted in the title. By making it a "rational" point, I am leaning, of course, toward the proclivities of politics and pointing out that universal service is a goal. Therefore, I am going to embrace universal service as a rational approach because, quite frankly, those of us in the regulatory business must contend with certain social and political pressures. For our purposes then, let us assume that universal service is something that is desirable and will be maintained.

As for a definition of universal service, I would say it has something to do with penetration rates. I can make it simple and say that if the penetration rate for local service were to increase, or at worst remain constant, in the years to come, then the public would be very happy with the system.

Another assumption I would like to make is that it is important to maintain residual pricing for local telephone service. In other words, we should maintain the view that a company needs
to earn its companywide revenue requirements and that local service is thereafter priced on a residual basis. The implication is that all aspects of the business, even those that have been deregulated, fit into the revenue requirement equation. The revenues to meet those requirements will not necessarily be generated by rates that are regulated. Furthermore, the rate of return must be disaggregated into components, each of which reflects the degree of competition in the service to which it applies. Permit me to illustrate graphically. The entire area of the box in Figure 1 represents the overall revenue requirement of the local exchange company (LEC).

The shaded side is the portion of revenues contributed by the many different types of services. Examples would be access rev-

enues contributed by interexchange carriers, MTS revenues, and those from enhanced services. The right-hand side of the box represents that portion of the required revenues to be derived from basic exchange charges. This is the residual, that is, total revenue requirements minus revenues contributed by other than basic exchange services. The areas X and Y are revenue responsibilities that were transferred from the nonbasic services to the basic services via the end-user access charges of June 1985 and June 1986. This revenue responsibility now belongs to basic exchange service. Typically, this is what is referred to as the unloading of network-sensitive costs to the local ratepayer.

Let me now propose the following: Regulators can regulate with one foot in a competitive environment and the other in a monopolistic one. Since this is a somewhat heretical proposition, I suspect it is going to need a lot of explaining. For the time being, the local loop is a monopoly service and is embraced by the local exchange company. This does not preclude deregulation in the future, but to reinforce my proposition, we will consider it to be monopolistic by franchise for the time being. The other services, such as those depicted on the shaded area of Figure 1, shall be priced competitively, as they already are in many cases. One thing that strongly favors the monopolistic local exchange company is that it controls the local loop, which clearly gives it a high degree of control over the price of access to its network by these other services.

While at first blush this may confer special benefits upon the LEC, further scrutiny reveals that such control, to a certain degree, is antithetical to the interests of everyone. First of all, there must be open access to the network (addressed in such cases as Computer III and Open Architecture). The interexchange carriers, the enhanced service providers, and all those other future possible services must have access to the network. The LEC may join that list of “vendors” and engage itself in the business of providing the enhanced services as well. In other words, it will have access to its own system, paying itself fees comparable to those paid by the other vendors. If it chooses to compete with the others, it needs merely sit back and collect the access fee revenues. In other words, the LEC may or may not choose to compete with the other vendors who are using its network; revenues will continue to flow.

Another point ripe for consideration is the abandonment of the
notion of cost-based pricing. While for years the idea of driving prices to cost has been prominent, there are, nevertheless, many instances of a clear departure from this notion, which is likely to continue. As long as universal service is to be pursued, of necessity there will be departures from cost-based pricing.

Let me take this a step farther, because under the structural conditions previously mentioned, the price-cost schism is not all that bad. This line of reasoning follows because the only real "provider" is the LEC because it controls the local loop. Prices then will be driven by end-users and vendors (including the local exchange company when it competes with the others as a vendor). The cellular companies are vendors, and the company offering packet switching as an enhanced service is, of course, a vendor on the other side of the street to the end-users. The LEC holds the key to exchange between these players. Herein enters the mechanism of value-of-service pricing.

Setting prices according to the value of service is a notion that has been around for a long while, and as long as the LEC maintains control of the local loop, then differential pricing could actually be desirable. Differential pricing in this context is perhaps a gentler, less inflammatory synonym for price discrimination. Predatory pricing is out of the question; reference here is to prices designed to meet the competition and which are therefore within the exemptions set forth under Robinson-Patman.

Differential pricing is utilized to maximize revenues, which in turn maximizes profits where the short-run marginal cost of providing the service is zero. Such is the case with the capacity on line at the local loop. The idea, in other words, is to maximize throughput on the system (to borrow some phraseology from natural gas). The price of access to interexchange carriers, for example, need not be chopped across the board in order to induce usage. Keep in mind that the price of access drives the price of the toll call to the end-user, and a great number of end-users are unlikely to respond positively to such a cut. In other words, why lower everyone's price if the idea is to induce usage among price-sensitive users. The big revenue generators are not the residential customers. Their demand is less price-elastic than that of those who would have the ability to bypass the network, and it is these latter who should be targeted for discounts. The LEC, which stands to lose the revenue through bypass, would be wise to accept a lower access fee from the provider of toll service to that end-user.

The most apparent virtue of such a pricing scheme is twofold: bypass is precluded, and when you can assume that the same pricing methodology is applied to all services, not just toll, then usage of the network in general increases. While the revenue requirements of Figure 1 remain the same, the revenues generated by nonbasic services increase. Revenue responsibility of the basic service can remain the same or even decrease, and the LEC can pocket the rest.

All of this is in keeping with my perception that "social contracts" are a bad idea. I do not think deregulation can be sold on a "no harm to the customer" basis. I believe it must be argued that, in fact, the local subscriber may gain from all this. By maximizing throughput on the network—achievable through differential pricing—such an outcome may be realized. No longer will we be compelled to transfer large chunks of revenue responsibility such as those depicted at points X and Y in Figure 1 to the basic subscriber. Rather, we can think of differential pricing, or discounting, as a series of little nibbles into that responsibility. The absolute worst scenario would be if every customer demanded a discount—every household and every business. If that were the case, we would be simply on the same bulk unloading track that we are now.

To sum up, let us assume that deregulation of the local loop is the subject of another day. I have thus attempted to present an outline of how state regulators can go forward at this point and accommodate the burgeoning load of competitive services. Again, if the LEC chooses to be a vendor and compete with other vendors accessing the network, it can. If it perceives the endeavor to be too risky, then it can simply sit back and collect revenues that are going to be flowing through the network from those who are competing for access. The core customers are called upon to share both the risks and benefits; revenue excesses would help sustain their subsidy. Revenue deficiencies would be made up in traditional rate cases.

If my discussion raises some hackles, then I have achieved my mission. If part of the fallout is the generation of a simple idea, I would be satisfied.
Is Equal Access an Adequate Justification for Removing Restrictions on BOC Diversification?

Lee L. Selwyn

Distinguishing Reality from Wishful Thinking

The title of this paper poses a question whose answer, at least at the present time, must be a resounding no. Yet only a few short years ago, when the antitrust settlement that would break up the Bell System was being crafted, there was a fundamental underlying assumption that "equal access" was somehow the key that would unlock competitive market forces that lay just below the surface of the system of economic regulation which has dominated the U.S. telecommunications industry for nearly a century. So we spent several years and several billions of dollars getting something close to this "equal access" vision. But where is the "effective competition" that was supposed to emerge? There are fewer incumbents in the "long distance" business today than at the time of the divestiture, and there is hardly any difference in the level of prices that the surviving "competitors" charge for

what have become almost undifferentiated "commodity"-type services. In fact, the creation of the post-divestiture "equal access" world is probably the single most important factor in realigning market conditions to a point where effective competition—indeed, the very sustainability of the limited competition that has developed thus far—cannot be viewed as a serious factor in shaping the extent of market concentration among "mass market" telecommunications providers.

Equal access eliminated the single most important "edge" that had been enjoyed by the start-up entrants—the ability to interconnect with local exchange carrier (LEC) exchanges and subscribers at a lower price than that which was being charged to AT&T. This single factor drove the pre- and immediate post-divestiture price differences that existed for mass market "long distance" services (see Charts 1 and 2 in Figure 1). Take that away, and the Other Common Carriers (OCCs) cannot price their services enough lower than AT&T to matter (see Charts 3 and 4 in Figure 2).

Unfortunately, the lessons of "equal access" have still not been fully appreciated. Equal access converted a differentiated product (the complex dialing arrangements required for OCC access vs. the "dial 1" scheme for AT&T) into a homogeneous commodity, resulting in less, not more, choices for customers and in less, not more, price competition in the marketplace. But what is "equal access" and where does it stop? Up to now, the term has been applied principally to connote "dial 1" type access to switched long distance carrier services. But the concept is already being broadened to embrace something called "Open Network Architecture" (ONA), a complex plan whereby even the most basic forms of exchange telephone service would be dissected into multiple parts any or all of which could be acquired and combined with "competitive" enhanced services so as to permit "competitors" to have the same degree of access to BOC resources as the BOCs themselves.

The very complexity of ONA—it will take almost two years just to develop the technical specifications—belie its potential effectiveness in assuring a competitive marketplace. In theory, the supplier of a competing service would be permitted to interconnect with the basic BOC infrastructure at any level, and would be required to purchase only those service elements that are actually necessary to support the application. In theory, the BOCs would themselves be required to pay themselves for equivalent intercon-
Is Equal Access Justification for Removing Restrictions?

**CHART 1:**

<table>
<thead>
<tr>
<th>Price per call</th>
<th>Access Cost</th>
<th>Net Price to ICC</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.00</td>
<td>0.75</td>
<td>0.25</td>
</tr>
<tr>
<td>1.50</td>
<td>1.00</td>
<td>0.50</td>
</tr>
<tr>
<td>2.00</td>
<td>1.25</td>
<td>0.75</td>
</tr>
<tr>
<td>2.50</td>
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<td>1.00</td>
</tr>
<tr>
<td>3.00</td>
<td>1.75</td>
<td>1.25</td>
</tr>
</tbody>
</table>

Note: In effect prior to May 25, 1985.
Based on 5-minute nonkey New York-Chicago call.

**CHART 2:**

Since 1985, CIC access charges have declined, while AT&T access costs have increased steadily.

Access Cost Per Call

- AT&T Access Cost
- ICC Access Cost

<table>
<thead>
<tr>
<th>Pre 5/84</th>
<th>7/84</th>
<th>7/85</th>
<th>7/86</th>
<th>7/87</th>
<th>7/88</th>
<th>7/89</th>
<th>7/90</th>
<th>7/91</th>
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<td>0.00</td>
<td>0.00</td>
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</tr>
</tbody>
</table>

Sample 5-minute call

**Figure 1.**

Lee L. Selwyn

connection schemes at the same prices they charge to others, hence the analogy to "equal access" in the "dial 1" context.

While there are at least as many reasons to expect that ONA will be even less successful in achieving a "competitive market environment" than the more limited "dial 1" equal access program, the establishment of ONA should still be required to stand up to an economic cost/benefit examination—that is, assuming that ONA could be the critical factor in the establishment of a truly competitive market environment (an assumption that is itself almost certainly false). Specifically, would the economic benefit of achieving such a "competitive" market environment, expressed in quantitative terms, exceed the economic costs of ONA implementation? Although I have an opinion as to the answer to that question (it is "no"), what is particularly remarkable, considering all the hype and hoopla that ONA has been receiving in recent months, is that none of its proponents has bothered to address this specific point.

ONA has to cost money—a lot of money—to implement. The planning and technical feasibility work is just the beginning; if ONA ever comes to pass, the overall cost of local (and for that matter, all) telecommunications services will have increased substantially. For want of a better caption, I would postulate two principles to describe, if not fully explain, how—and why—this will happen:

**SELWYN'S FIRST LAW:**
The price of a product or service increases as the number of individual rate elements increases.

**SELWYN'S SECOND LAW:**
The price of an individual rate element increases as the number of letters in its descriptive acronym increases (e.g., a TXQR/736 will, all other things being equal, tend to cost more than a TXQ).

The confluence of both of these "laws" suggests that, as the pricing structure becomes more complex (hence requiring longer and more complex acronyms), the overall price of the product or service will tend to increase exponentially. The processes contemplated by these postulates are readily apparent. When an integral product or service is "unbundled" by carving it up into smaller pieces, a whole array of new costs are introduced that are simply
not present when the service is offered on a "packaged" bundled basis. At a minimum, the supplier encounters new costs of administration, inventory management, packaging and delivery. But as often as not, in order to sell a product in piece-parts, additional design and engineering has to be introduced into each component to assure interconnectivity and compatibility, since the responsibility for assembly of the various components is shifted from the supplier to its customer. It is well known that the price of an automobile is lower than the collective prices of all of the individual component parts. The nature of products and services in our economy is the result of collective consumption decisions that define and describe the general mass market requirement; when someone needs something customized, the price goes up—and often by a large amount.

It is ludicrous to believe that merely by creating an ONA environment (assuming that this could even be accomplished) one eliminates the opportunities for the dominant supplier (of bundled products and services) to gain competitive advantage in the marketplace. But even if that "dream" could be realized, it is less than clear that the public would want to—or that it should be forced to—pay the price. We should be looking past these superficial solutions and instead confront the economic realities of the production of telecommunications services. And when we do, it must become clear that the national interest remains in maintaining the efficiencies of large scale provision of local distribution, access, switching and transport services and not in looking for ways to permit the trustees of these local network infrastructures—the BOCs—to obtain an even greater advantage from their control of these resources than they presently enjoy.

Criteria for Reviewing Whether MFJ Restrictions Are Necessary

The original theory of the AT&T/BOC divestiture was to isolate the control over monopolistic local exchange distribution, local access, and LATA transport services from the provision of the potentially competitive customer promises equipment, intercity (long distance) transmission, information services, and equipment manufacturing operations. Monopoly control over the "bottleneck" distribution facilities and services by the BOCs affords these companies both the opportunity and the incentive to seek to
extend their market power, rooted in the local service monopoly, into potentially competitive areas unless such efforts are affirmatively constrained by the regulatory process. These conditions will persist so long as the BOCs continue to dominate the provision of local distribution, local exchange, and access and LATA transport services and their associated network infrastructures. Thus, an affirmative demonstration of the erosion of BOC market power to a point where such opportunities are no longer possible is fundamental to the relaxation or elimination of MFJ restrictions the effect of which would be to increase the BOCs' opportunities to engage in such practices.

Evaluating BOC Market Power Based upon Real Economic Conditions

In assessing the degree to which a level of effective competition that is capable of acting as a constraint upon BOC market power has developed or could reasonably be expected to develop, it is essential that one examine the underlying source of such competitive activity, and in particular, determine whether it has been driven by fundamental economic conditions of supply (e.g., technology, scale economies, specialization) in contrast to pecuniary or pricing distortions created by the regulatory process itself. When observed competitive activity in a market is not rooted in fundamental economic conditions, but is instead merely the product of historical (often politically motivated) pricing policies, there is no reason to expect that such competition will be viable or sustainable in the long term once the distortions which gave rise to that "competitive" activity in the first place are eliminated. Examples of such pecuniary conditions extant in the telecommunications field are the access charge discounts available to non-dominant interexchange carriers over the past several years and now in the process of being phased out, and the pervasive use of broadly-averaged prices by dominant carriers. (It should be noted that as a result of the phase-out of access charge discounts available to the OCCs, the price differential vis-à-vis AT&T that OCCs are capable of offering to customers has narrowed or disappeared entirely (see Charts 3 and 4), and there is the very real possibility that AT&T's post-equal access market share could actually increase as competing carriers, confronting diminishing profitability, are forced to back down from aggressive expansion programs or drop out of the market entirely.)

Note that it is not the purpose of the present writing to consider, one way or the other, the matter of the public benefits of either maintaining or of eliminating these historical pricing conditions. What is critical to recognize for our present purposes, at this juncture in the development of telecommunications policy, is that the historical practice of recovering non-traffic-sensitive (NTS) costs through usage-based charges, or of broadly-based geographical and scale rate averaging, cannot readily coexist with open entry policies except if the practical effect of such entry is limited to highly specialized services and "niche" markets. "Equal access," for example, at best eliminates only the physical differences in the manner by which users access interexchange carriers, or the differences in the prices that such carriers pay to the local exchange carriers for interconnection to end users. Equal access does not in any sense imply an end of the NTS subsidy or of the rate averaging policies that pervade existing LEC and AT&T rate structures. Accordingly, equal access, per se does little to resolve the inherent conflicts between the historical pricing goals and a general open-entry policy.

An analysis of the markets for BOC services leads to the following conclusions:

1. That a substantial amount of the existing competition for BOC basic local exchange, access, transport and distribution services has been fostered not by fundamental economic conditions of supply, but rather by pecuniary distortions created by the regulatory process itself, and that, absent such distortions, the limited amount of competitive activity that exists at the present time would be even smaller and, in certain areas, non-existent.

2. That these limitations on the availability of viable competitive alternatives are pervasive throughout the marketplace, and are equally applicable to smaller residential/business customers and to large business and government users.

3. That the basic local services infrastructure (consisting of local exchange distribution facilities, central office termination facilities, local switching facilities, and local transport and network switching facilities) is subject to natural monopoly conditions.
Specifically, the presence of substantial economies of scale and scope is such that the BOCs can provide services over their basic infrastructure on a monopoly basis at a lower economic cost than can any other potential provider, who would ultimately be required to provide and construct what are fundamentally duplicative facilities.

4. That many specialized and dedicated services employed by larger business and government users are essential to the efficient operation of their (non-communications) business activities, and that the use of such facilities from whatever source they may be obtained does not per se constitute a "bypass" of the BOCs' services nor affirmatively demonstrate the existence of effective competition for BOC access and transport facilities.

5. That the apparent availability of so-called "bypass" opportunities to large users derive not so much from economies of scale but from the manner in which basic local exchange, access and transport services, when offered by the BOCs, are priced, and that these opportunities would largely evaporate if rational, economically sound cost-based pricing policies such as those adopted initially by the FCC in its original Access Charge order [FCC Order 82-579, released February 28, 1983; 48 F.R. 10319, March 11, 1983] were put into effect.

6. That BOC behavior in the marketplace and before regulatory agencies at both the state and federal levels belies their assertions as to the presence of viable competition for their basic access and transport services.

7. That actual, "real world" experience of some of the nation's largest telecommunications users indicate that, while non-BOC sources are utilized, their penetration into the market for basic access and transport services as used by these large consumers can be characterized as only slightly above the de minimus level.

Effects of Relaxing MFJ Restrictions
Given Continued BOC Dominance

To the extent that the BOCs continue to dominate the local exchange, distribution, access and LATA transport markets, the presence of economic regulation of their rates and earnings at both the state and federal level protects large and small—from the potential monopolistic price levels that might exist in the absence of constraints on the exercise of the BOCs' market power over these services. If the MFJ restrictions are modified or eliminated on the assumption that such market power is no longer present (when in fact it is as pervasive as ever), and if that same assumption is also used to justify relaxation of economic regulation of BOC basic exchange and access services, then it is reasonable to expect that BOC rates for these monopoly services will rise. Moreover, to the extent that relaxation of MFJ restrictions introduces new opportunities for the BOCs to engage in explicit or implicit cross-subsidization of their competitive activities with monopoly earnings from basic exchange, access and other LATA services, further upward pressure on BOC price levels can be reasonably anticipated. On the other hand, there seems little likelihood that BOC entry into markets that are already competitive will result in consequentially lower prices. Indeed, unrestricted BOC entry into these markets would result in lower BOC price levels only to the extent there exists a clear economy of integration between the basic exchange, access or transport service and the proposed new BOC activity and where the economic benefits of that integration are passed on to the public. Ironically, however, the presence of such an economy of integration will actually serve to increase the BOCs' opportunity to extend the market power derived from their monopoly services into more competitive markets. As a consequence, BOC entry into such markets is as likely to result in reduced competition and increased concentration, and prices even in the nominally competitive industry segments could be expected to increase.

Three Approaches BOCs Could Use to Exploit Their Market Power in Regulated Markets and to Gain Unfair Advantage in Non-Regulated Markets

While the specific rules governing structural separation and entry into non-regulated lines of business are still fluid, the underlying intention of FCC and Federal District Court policy remains clear: the offspring of the divestiture of AT&T, to whatever extent they may elect and be permitted to enter new fields of activity, are not being granted a license either to disadvantage customers of their regulated services nor gain an unfair advantage in the
non-regulated markets by virtue of their monopoly control of, or dominant position in, the regulated segments of the telecommunications industry. Given that the likelihood of any significant level of effective competition in regulated BOC markets is extremely low, there are three general approaches which BOCs could use at the expense of users of regulated services to gain an advantage in non-regulated markets:

**Diversion of resources.** Confronted with the opportunity to enter non-regulated, potentially more profitable areas of business, the local telephone utility and/or its parent may allocate its capital, managerial, technical and other resources in such a way as to favor the non-regulated competitive lines of business and, as a consequence, disadvantage the regulated basic telecommunications services that it is required to provide.

**Use of ratepayer-funded resources to enter non-regulated businesses.** The local exchange carrier has both the incentive and opportunity (unless limited by regulatory action) to utilize ratepayer-provided funds to absorb many of the risks and investment costs associated with entry into new lines of business. It can acquire new plant with capacities and capabilities that will permit the development of “enhanced” services to be offered on a non-regulated basis at some future date, and can use ratepayer funds to pay for the research and development of future non-regulated competitive services, and for the retirement of plant that could not provide non-regulated service.

**Extension of market power derived from regulated services into non-regulated markets.** The local exchange carrier has the opportunity and incentive to extend its control of regulated markets into “competitive” areas by means of, among other things, access to customer information and market data, and the potential for integrating the regulated and non-regulated services into bundled “packages” supported by a common capital, marketing and maintenance resource base.

While structural separation—and as now proposed by the FCC, accounting controls—are regarded as methods for limiting the dominant carriers’ cross-subsidization and unfair competitive advantage opportunities, neither structural separation nor accounting controls can assure that such practices will not continue to take place. This is because both approaches address only explicit forms of cross-subsidy between affiliates; they cannot prevent the kind of cross-subsidies that arise as a result of the transfer of resources that do not appear as assets on the affiliates’ financial statements or, if they do, are not carried thereon at their full economic value. Structural separation or accounting controls will not prevent the reassignment of personnel from the regulated to the non-regulated entity, nor will they forestall the possibility of inter-temporal cross-subsidies that can result from a change in the definition of the scope of regulated services over time.

**Conclusion:** The policy goal is economic efficiency; BOC diversification is at best only one possible way of getting there.

Questions such as whether or not BOCs should be allowed entry into new markets, or if entry into new markets is allowed, the types of regulatory safeguards that would need to be established to protect existing BOC ratepayers, are inextricably tied to answers regarding the nature and extent of competition in existing BOC markets. To the extent that the services presently being offered by the BOCs under regulation are not now subject to viable competition or are likely to be so subject in the near future—conditions which, based upon evaluations of underlying economic conditions, are more than likely the case—substantial opportunities will be available to BOCs to cross-subsidize new non-regulated services at the expense of ratepayers of existing BOC services. Moreover, to the extent that underlying economic conditions such as the existence of substantial economies of scale or scope in telecommunications network infrastructures work against the possibility of effective competition ever developing, or if it does develop, remaining viable and sustainable in the long term, mechanisms such as equal access, or its local exchange network equivalent, “Open Network Architecture,” will accomplish little in the long term besides engendering additional layers of costs and complexities to be imposed upon society. In sum, the public at large will realize few, if any, benefits from the elimination of existing MFJ restrictions on BOC activities—but could be exposed to substantial costs and risks if such actions are taken in the face of continued BOC dominance of the local exchange and LATA services markets. The relevant—and indeed the only really important—policy question is not what is good for the BOCs, but what is good for the public.
and the economy generally. A pervasive public benefit from BOC diversification and entry into new markets has simply never been affirmatively demonstrated, and unless and until it is, the BOCs should be encouraged to devote their resources and expertise to the efficient fulfillment of their primary and historical mission: the efficient provision of basic distribution, access, local switching and transport services to all telecommunications users.

Competition Policy in the Post-Equal Access Market

John Haring and Evan Kwerel

The two conditions that the U.S. Department of Justice and District Court Judge Harold Greene deemed necessary to prevent AT&T from exercising monopoly power and that were embodied in the Modified Final Judgment (MFJ) in United States v. AT&T have now been substantially achieved. First, AT&T has been divested of the Bell Operating Companies (BOCs). It thus no longer has the opportunity to provide discriminatory interconnection to competitors or the ability to subsidize the prices of its interexchange services with revenue from local exchange services or to shift costs from competitive interexchange services to local exchange services. Second, the BOCs are offering their customers

Note: The views expressed are those of the authors and do not necessarily reflect the views of the Federal Communications Commission or any other organization or individual. We wish to thank Peter Fitch and Tom Spawins of the Office of Plans and Policy for helpful comments, and Peyton Wynne and Jonathan Kraushaar of the Common Carrier Bureau for germane data.
equal access to all long distance companies to the extent required by the MFJ. As Judge Greene noted, "with the removal of these barriers to competition, AT&T should be unable to engage in monopoly pricing in any market." We believe that achievement of the relief sought by the government in United States v. AT&T provides a logical and compelling basis for now undertaking revisions in the way in which the FCC regulates AT&T. Indeed, if now is not the time for change, it is not clear when will be. There are no other obvious trigger points to motivate revisions in the commission's regulation of AT&T.

There are two basic reasons for undertaking change now, and they relate to the two basic functions regulation performs. Regulation is, in the first instance, a substitute for competition. Ideally, properly functioning regulations bring about the results that properly functioning markets would if competition were feasible. It follows that as market imperfections are removed (as they have been) and competitive forces play an increasingly predominant role (as they do), the need for regulation as a substitute for competition is diminished. Maintaining unnecessary regulation would clearly be wasteful in that it would involve incurring unnecessary costs and, what is even more important, could actually stifle desirable competition that would bring benefits to consumers. Note also that traditional rate-of-return regulation is likely to become increasingly ineffective and unworkable as competitive forces operate because the regulated firm's profit rate is increasingly beyond its control. The postdivestiture AT&T enterprise is no longer a very capital-intensive business; consequently, relatively small shifts in its income cause relatively large shifts in its profit rate.

Regulatory policies may also serve as a complement to competition. For example, policies providing for equal access and for toll deeding promote competition by, respectively, lowering entry barriers and expanding the extent of the market and hence the room for competitors. But while good regulation can help the competitive process to function effectively, regulatory failures clearly can prevent it from working. These failures may involve errors of omission as well as commission. Important in this regard are questions related to the allocation of resources in the interexchange business. In its submission to the FCC's Docket 83-1147 investigation of long-run deregulation of AT&T, the Ad Hoc Telecommunications Users Committee, a group of very large telecommunications users, argues that "such competition for AT&T's intercity transmission services as has developed up to now has been primarily driven not by any real economic foundation, but by entirely pecuniary distortions, principal among which are discounted access charges and rate averaging." While we believe there are reasons to be somewhat skeptical of this claim, ultimately the only way to prove or disprove it is a fair market test. The relief sought by the government in United States v. AT&T, approved by Judge Greene, and now substantially effected was intended to destroy artificial impediments to competition. It would be unfortunate if the FCC were now to allow its regulations and processes to operate or be exploited in ways that are fundamentally inconsistent with competitive market processes. One way to avoid this outcome would be to adopt policies that are less susceptible to error or abuse than current ones.

This paper is organized in the following manner. First are described in qualitative terms the avoidable costs of current regulation, that is, costs that need not be incurred to protect consumers from monopoly abuse. Next is provided a thumbnail sketch of the current state of competition in the interexchange market, including an evaluation of the extent of AT&T's market power. The following section outlines a proposal for revision of the commission's regulation of AT&T that we believe protects consumers who lack competitive alternatives at the present time and obviates concerns about predatory pricing or cross-subsidization. The last section is a brief summary.

**Avoidable Costs of Regulation**

The direct costs associated with the FCC's current regulation of AT&T are not insubstantial. One study submitted in the FCC's Docket 83-1147 deregulation inquiry estimated that direct costs, excluding AT&T's costs, were more than $40 million per year and that annual savings of between $15 and $25 million were possible. In addition to these direct costs, it is also necessary to reckon the opportunity costs of the resources expended under current regulation to gauge the full extent of the regulatory cost burden. Opportunity costs measure the value of what could have been produced with given resources in their most valuable alternative employment. In other words, they represent the value of what we sacrifice by using resources one way rather than another.
Given the existence of less resource-intensive methods of effectively regulating AT&T, the opportunity costs of failure to adopt such methods consist of the benefits wasted resources could have produced in alternative employments. The true economic costs of technically inefficient regulation of AT&T include, inter alia, the benefits society necessarily forgoes from less effective regulation of access tariffs, accounting separations, and other important activities of the commission. As a result of the Bell System divestiture, the FCC now regulates not only AT&T but also the access tariffs filed by the Bell and other telephone operating company monopolies. The latter constitutes a monumental undertaking involving a very substantial commitment of resources that, prior to divestiture, was unnecessary. Also, in its Computer III Rulemaking the FCC now contemplates substitution of accounting controls for separate subsidiary requirements to regulate supply of local information services by the telephone operating company monopolies. To be effective, accounting controls will also require a very substantial commitment of resources to evaluate and monitor compliance with accounting separations plans. Finally note that at a time when the commission’s resource requirements are growing, its budget is shrinking in real terms and is likely to continue to do so for the foreseeable future. The upshot is that the opportunity costs of the commission’s increasingly scarce resources are very high indeed.

To maximize the benefits society derives from its existence, the FCC should allocate its scarce resources so that, at the margin, the net payoff to an additional expenditure on any given activity is equalized. The effect of divestiture, equal access, and greater competition in long distance communications is to reduce the societal payoff to regulation in this sector relative to others. Regulated resource management in this circumstance requires reallocation of resources away from that activity where regulatory productivity has fallen relatively and toward those activities where productivity has risen relatively.

In addition to the direct and opportunity costs of the resources involved in administering current regulations, it is also necessary to consider the economic losses those regulations impose on consumers. Regulation may be conceived as the cure for some problems, but it is incontrovertibly the cause of others. That society benefits on net is certainly disputable. In our view, the principal effect of current regulation of AT&T is creation of equities in the status quo, regulation merely serving to isolate firms from competitive market pressures. We focus on three important adverse consequences of current regulation. The first is that rate-of-return regulation significantly weakens the economic incentive for a regulated firm to minimize costs and to maximize the benefits it provides the public. Inflated costs may take many forms—plush offices, overdesigned equipment, high salaries, or a bloated work force. Economists have focused most of their attention on one distortion, overcapitalization. If regulators set the allowed rate of return above the cost of capital but keep prices below the profit-maximizing level, a regulated firm will have an incentive to expand its ratebase beyond the cost-minimizing level. Regulators have attempted to deal with this adverse side-effect of rate-of-return regulation by requiring regulated firms to gain approval for investment in new facilities. In practice such requirements have not been very successful. The FCC has, for example, approved all of AT&T’s requests for new international cable facilities even when there was little demonstrated need for additional capacity.

Even more difficult than preventing inflated costs is assuring that a regulated firm effectively serves its customers’ needs. Assuring that prices reflect costs and that costs are minimized are fine goals, but they are not enough if the products and services consumers desire are not produced. In this respect, AT&T’s performance in the customer premise equipment market was certainly never anything to write home about and, in general, inferior to the performance of that business segment under competitive organization.

A particularly troubling aspect of this general problem of incentives is the lack of incentive a rate-of-return-regulated firm has to introduce product and service innovations. Because the regulated firm’s profits are restricted, its incentives to seek out lower cost methods of production or innovative services are also restricted. From society’s point of view, there is nothing wrong with profits per se. It is ill-gotten profits that society dislikes and, with justification, seeks to discourage. The trouble with rate-of-return regulation is that it does not distinguish between profits generated by monopoly pricing behavior and profits generated by socially desirable innovative activity. It throws the baby out with the bath water.
The second adverse effect of current regulation is to divert resources away from marketplace competition to competition within the regulatory and political arena and, thereby, to stifle the competitive rivalry that most benefits consumers. To reduce rates or introduce new services, AT&T must first convince regulators that its proposed changes are cost-justified. That task is formidable enough in the presence of common costs and uneconomic regulatory cost standards, but when its competitors are permitted (and thus given additional incentives) to delay and harass AT&T, passive, noncompetitive behavior on AT&T's part is encouraged. Vigorous competition is thereby discouraged, and consumers' expectations are likely to be frustrated. In this regard, note that AT&T's competitors have opposed virtually every price reduction proposed by AT&T in the period since divestiture and have in many cases successfully delayed the availability of beneficial price cuts to consumers. No one concerned with the economic welfare of consumers can logically argue that toll rates should be kept artificially high and that the FCC should practice handicapped regulation and umbrella pricing in toll markets.

A third important adverse consequence of current regulation is that it prevents the commission from acquiring the information it needs to make a reasoned determination about the long-term viability of competition in the long distance business. Current regulation makes it impossible to distinguish whether the market entry we observe reflects actual comparative efficiencies on the part of competing firms or is merely a response to distortions introduced by regulation itself and hence not sustainable as the distortions are mitigated by competition. Without knowing the genealogy of observed entry, it is impossible to prescribe, with any acceptable degree of confidence, long-term regulatory policies that will promote consumer welfare. How can the commission presume to act in the public interest when it lacks the information it needs to make reasoned policy determinations?

The Extent of AT&T's Market Power

Market power is the ability of a firm to maintain prices profitably above minimum costs of production for an extended period. We assume that the purpose of regulating AT&T is to limit the exercise of market power. It follows that to the extent AT&T's market power is being dissipated, the putative benefits of regulation are declining.

While one cannot be a little pregnant, a firm can have a little market power. Indeed, most firms in the economy possess some. Showing that a firm possesses market power is not sufficient to justify regulation. Instead, the relevant question is at what level of market power do the benefits of regulation outweigh the costs. We believe that AT&T's ability to raise prices above competitive levels has fallen to a point where the benefits of rate-of-return regulation fall short of its costs. We will propose a streamlined form of regulation to limit AT&T's ability to exercise whatever market power it may still possess.

Analytical Framework

A firm's ability to raise prices profitably above the perfectly competitive level depends on the degree to which it loses customers as it raises its price. The more customers it loses, the less its price will deviate from the competitive level. In technical economic terms, a firm's market power may thus be said to vary inversely with its perceived elasticity of demand, the latter defined as the percentage loss in quantity sold when price is raised by one percent.

When one firm in the market acts as a price setter while the remaining firms act as price takers, the elasticity of demand ($e_d$) facing the price-setting firm can be expressed in terms of the market elasticity of demand ($E_d$), the elasticity of supply of the other firms in the market ($E_s$), and the price-setting firm's market share ($\sigma$). It can be shown that

$$e_d = \frac{E_d}{\frac{\sigma}{E_s} + \frac{1 - \sigma}{E_s}}$$

We consider each of these three factors as they apply to AT&T.

Market elasticity of demand. One constraint on AT&T's market power is the market elasticity of demand. If the price of long distance services were to rise, then customers would reduce their total consumption of such services. They would economize on their calling and substitute postal services, personal visits, and other alternatives for telephone communication. Some calling might be forgone altogether, and other calls might be of shorter duration.
From equation (1) it is clear that the greater the market elasticity of demand ($E_d$), the greater is the elasticity of demand faced by AT&T, other factors the same. Econometric studies suggest that the market elasticity of demand for long distance services is on the order of .5 in the short run and approximately unitary elastic in the long run after consumers have had a chance to adjust their consumption. These elasticities imply that if AT&T were to raise price, its revenue would increase in the short run and remain roughly constant in the long run, assuming the absence of rival firms. Since its total costs would fall or remain constant as output declined, its total profit would rise.

Supply elasticity of competitive fringe. Another constraint on AT&T’s willingness to raise its prices is its fear of losing customers to its rivals. In terms of equation (1), the larger the elasticity of supply ($E_s$) of the competitive fringe, the larger is the elasticity of demand perceived by AT&T. If AT&T’s competitors increased their output by a large amount in response to a price increase, AT&T would lose a large percentage of its sales to other firms by raising price.

One indication of large elasticity of supply in the long distance business is the rate and relative ease with which productive capacity is being expanded. A survey by the Hudson Institute indicates that firms other than AT&T plan to add more than 5.3 billion circuit-miles of fiber-optic capacity to the U.S. long distance telephone network by 1988. This would represent a 379 percent increase over the approximately 1.4 billion circuit-miles of total U.S. capacity in 1985.

According to a recent survey conducted by the Industry Analysis Division of the FCC’s Common Carrier Bureau (CCB), carriers other than AT&T have already put in place large amounts of fiber-optic transmission capacity. The CCB estimates that about 650,000 fiber-miles of capacity was installed by the end of 1986 by carriers other than AT&T. (See Table 1.) That capacity could provide approximately 1.6 billion two-way circuit miles using current optical electronics technology and more than 4 billion circuit miles using terminal and repeater technologies likely to be available in the near future. The presence of such huge amounts of easily expandable capacity clearly constrains AT&T’s ability to exercise market power by restricting output. Note also that once

<table>
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<th>Carrier</th>
<th>Fiber-miles</th>
<th>Percentage</th>
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<tr>
<td>AT&amp;T</td>
<td>261432</td>
<td>30%</td>
</tr>
<tr>
<td>U.S.-Sprint</td>
<td>172460</td>
<td>19%</td>
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<tr>
<td>MCI</td>
<td>167400</td>
<td>18%</td>
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<td>Lightnet</td>
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<td>6960</td>
<td>1%</td>
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capacity is installed, it is effectively sunk and cannot exit. That means that while the identities of future competitors may differ from those of current competitors, there will, in fact, be supply alternatives in the future. Huge increases in supply relative to demand spell lower and lower prices well into the future.

Market share. Market share is another factor to be considered in analyzing market power. Holding constant the market elasticity of demand and the elasticity of supply of competitors, equation (1) indicates that the larger a firm’s market share, the smaller is its elasticity of demand and, hence, the greater its market power. Of course, equation (1) also shows that market share is only one factor affecting market power. Even if market share were large, market power would be small if the market elasticity of demand or the elasticity of supply of competitors were large.

The influence of market share can be decomposed into its interaction with the market elasticity of demand and with the elasticity of supply of competitors. To simplify the exposition, we will assume that the elasticity of supply is zero when discussing the market elasticity of demand and vice versa. First, consider the influence of market share on the relationship between the market elasticity of demand and the elasticity of demand facing the firm. The smaller the market share of the price-setting firm, the greater is the percentage reduction in its output for a given percentage.
reduction in market output and, hence, the greater its elasticity of demand relative to the market elasticity of demand. For example, if the market output is one hundred units while the firm’s output is ten units, a reduction of five units in output would represent a 5 percent reduction in market output but a 50 percent reduction in the individual firm’s output.

Similarly, as the firm’s market share falls (and the share of the competitive fringe increases), a given percentage increase in supply by the competitive fringe will represent a larger percentage increase relative to market output and a larger percentage decrease in the sales of the price-setting firm. This means that the price-setting firm must reduce its output by a greater percentage to achieve a given percentage increase in market price, the smaller its market share, given the elasticity of supply of the competitive fringe and the market elasticity of demand.

AT&T’s share of the long distance business has been steadily declining. Table 2 shows that AT&T’s share of the interstate toll market has dropped significantly during the last two years. Its share of total minutes fell from about 83 percent to 77 percent. In those particular market segments where the OCCs have chosen to compete, AT&T’s market share has fallen to significantly lower levels. One study estimated that AT&T’s share of the business in “contested” market segments fell below 70 percent in 1986 and would be less than 60 percent by 1988.19

These figures overstate AT&T’s prospective market power because they reflect historical sales, rather than the ability to compete for customers in the future. Thus AT&T’s share of productive capacity may be a better measure of its market power. That share is falling quite precipitously. Table 1 shows that as of year-end 1986, AT&T controlled only 29 percent of fiber optic interexchange capacity. Even when conventional capacity is included in the calculation of capacity share, AT&T’s share falls well below 50 percent.

Additional Considerations

For purposes of analyzing market power, certain other considerations may be usefully taken into account. These include the geographic location of call origination and destination, type of service, and customer size.

Call Destination—International Calls. The market power analysis given above is not applicable to the international market. The most significant difference between that and the domestic market is that foreign telecommunication authorities (PTTs) control access to foreign markets but are not subject to U.S. regulation. In such an environment, market power possessed by U.S. international carriers could, in fact, serve U.S. interests by counterbalancing the market power of PTTs. Rate-of-return regulation does not protect the interests of U.S. consumers of international telecommunications, in any event, because it permits regulated U.S. carriers to pass on the costs of payments to monopoly PTTs.20

Originating Exchange—Equal Access, Presence of Competition. The degree of AT&T’s market power for interstate switched voice service (MTS) may vary across local exchanges depending on the presence or absence of competitors offering such service in a particular exchange and on the availability of equal access. As part of the divestiture agreement between AT&T and the Department of Justice, the BOCs are required to offer all long distance carriers access that is "equal in type and quality" to that provided to AT&T. Likewise, the GTE Consent Decree requires the eighteen GTE telephone operating companies to provide equal access interconnection. Equal access assures all long distance carriers equal transmission quality, permits all carriers to offer service to customers with rotary as well as tone phones, allows customers to
reach all carriers by dialing the same number of digits, allows all carriers automatically to identify the phone number of the party originating a call on its network, and allows all carriers to determine precisely when a call has been terminated. Under the divestiture agreement, each BOC was required to offer equal access in offices serving at least one-third of its lines by September 1, 1985, and to offer it in the remaining end offices by September 1, 1986, "upon bona fide request."

By the end of 1986 about 70 percent of all lines were converted to equal access.21 Of course, many people without equal access still have a choice of two or more carriers, albeit in a less convenient but also less expensive form. Assuming that all the people with equal access have a choice of carrier but that only half the customers without equal access have such a choice, about 35 percent of all customers had a choice of two or more carriers by the end of 1986.22

While AT&T's market power may be greater in those exchanges currently lacking actual competitors, its market power is still, of course, limited by the ability of competitors to enter these markets. Expansion of an existing network into new territory is easily accomplished. Moreover, it is certainly possible that AT&T's market power may actually be less in markets without equal access than in those with it. This is merely a reflection of the generous 55 percent discount on access charges OCCs receive for nonpremium service. That discount more than compensates these carriers for lower quality interconnection. Thus OCCs are more likely to be able to undercut AT&T's prices and expand output at AT&T's expense in exchanges without equal access, other things being equal.

Type of Service—Switched v. Private Line. One would expect the private line market to be more competitive than the switched services market because private line users are highly sophisticated and have enough at stake financially to justify shopping carefully for the best deal. Indeed, the private line market was the first service to experience competitive entry. Yet, the fact that few carriers currently offer private line services relative to the number offering switched services suggests that the former market may be less competitive than the latter. The lack of suppliers may, however, be a result of regulation and not an indication of the potential long-

run competitiveness of the private line market. There may be few firms offering private lines because users have been effective in persuading regulators to hold down AT&T's private line prices. Individual private line users may save enough from a reduction in rates that it pays them to participate actively in the regulatory process. The fact that AT&T reported a negative rate of return on private line services of 4 percent for 1984, at the same time that it reported positive earnings of 15 percent on switched services, is strong evidence that regulation has held private line rates below the competitive level.23 Absent regulation, AT&T would have the freedom to raise its prices for private lines, but if it did, new competitors would quickly enter the market. Moreover, many private line users are large enough that they may be able to put together their own system. Alternatively, large users might sign long-term contracts with AT&T's competitors, thereby sharing the risk that AT&T might lower its prices.

Transactions Costs, Product Differentiation, and Size of User. The model discussed in Landes and Posner's article assumes a homogeneous product, perfect information about prices, and no transactions costs involved in changing suppliers. Under these conditions, a firm raised its price above that of other firms, it would lose all its sales. Thus, there would be a single market price in equilibrium. In their model, the dominant firm raises the market price by reducing its output. This describes some markets better than others. For example, it may be a reasonable description of the market for oil in the early 1970s; Saudi Arabia was a dominant supplier at that time and was able to raise the world price of oil by reducing its output.

In the telecommunications market, however, individual carriers do not all charge the same price for a service. One reason is that the products offered by different vendors are not identical. For example, people appear willing to pay more for more reliable or clearer connections. Another reason is that it is costly to become fully informed about prices and service characteristics. It is also costly to calculate whether it pays to switch to a new carrier. It may not pay small users to incur these costs, so they may continue to use AT&T even if they might be better off if they could costlessly switch to some other carrier.

Transactions and information costs may thus give an incum-
bent firm such as AT&T a modicum of market power. The profits obtainable from raising price to these users are limited, of course, by the small volume of calls each user makes, the modest size of relevant information and transactions costs, and the ability of competitors to reduce the information costs by advertising. The more AT&T seeks to extract a premium over cost, the greater is the incentive of its competitors to advertise that fact.

Proposal

We have argued that AT&T's ability to raise prices above competitive levels is generally constrained by the ability of competitors to expand their output and the demonstrated willingness of customers to switch to alternative sources of supply. Yet, there may be some areas in which AT&T retains market power. Small users in exchanges currently served only by AT&T might be one example. Such exchanges are typically in rural areas served by independent local exchange carriers.

Note, first, that requiring AT&T to maintain a single nationwide price schedule limits its ability to exercise market power in any particular geographic region. AT&T cannot raise prices for those customers who currently have no choice of long distance carrier without simultaneously raising the prices for those who do. Uniform nationwide pricing requirements place less of a constraint, on AT&T's ability to raise prices in the submarket composed of small users. AT&T already serves these customers and may derive some limited market power from the fact that it may not pay such customers to incur the information and transactions costs involved in finding a lower priced carrier. Even with the requirement that AT&T maintain uniform national prices, AT&T could conceivably establish a set of optional calling plans that allowed it to charge lower prices to high volume customers for which AT&T faces intense competition and higher prices to those small volume customers for which it faces less intense competition.

There are several options for dealing with the possibility that AT&T may retain pockets of market power in a limited number of areas. One is to continue subjecting AT&T to the current form of regulation in all markets because some markets may not be competitive. The second is to deregulate only those markets deemed competitive. The third is to deregulate all markets despite the fact that some may not be competitive in the short term. Finally, there is the option we examine here. The essence of our proposal is to replace rate-of-return regulation with a price cap on a limited set of "core" services that must be offered in all markets. We consider each option in turn.

Continuing to regulate AT&T in all markets has little to recommend it. It would be a mistake to forgo the benefits of rapid introduction of new services and innovative pricing schedules in all markets because AT&T retains some residual market power in certain areas.

Market-by-market deregulation would present great administrative problems. Many of AT&T's facilities simultaneously serve both regulated and unregulated markets, and there is no meaningful (that is, economically nonarbitrary) way to apportion joint costs between separate markets. The FCC might find itself bogged down in endless debates about cross-subsidies between regulated and unregulated markets.

Complete deregulation appears to be the best long-run approach. It eliminates the distortions associated with rate-of-return regulation and gives AT&T the freedom to introduce new services and pricing options without lengthy regulatory delays. But, as noted above, it fails to account for the possibility that AT&T may retain some market power over small customers in exchanges without equal access and where rivals are absent and not likely to enter because of the small number of customers to be contested.

We believe the fourth option offers the best balance between preventing AT&T from exploiting any residual market power it possesses and providing customers with the benefits of more innovative price and pricing. The essence of this approach is to replace the current system of rate-of-return regulation with a price ceiling on a small set of core offerings. These would be defined so that for any service over which AT&T has significant market power, that service would either be within the core or there would be a close substitute for the service among the regulated core services. AT&T would be required to offer the core services at a uniform price throughout the country. These core services might include MTS and WATS or perhaps only MTS. Private lines probably would not be classified as a core service because this market is potentially highly competitive (that is, AT&T lacks significant market power).

The price cap on core services would initially be set at the
current level. A formula would then be established for changes in the cap. For example, the cap might be indexed to reflect changes in the purchasing power of money as well as the rate of long-term productivity growth in the telecommunications industry. The cap should also be adjusted to allow for changes in access charges. AT&T would be free to set the price of services outside the core offerings in any way it chose subject to continuation of the current nationwide averaging requirements. It would also be free to offer any new services without FCC approval.

Setting a price ceiling on a set of core services would constrain AT&T's pricing of all services while avoiding the delays (and opportunities for abuse of regulatory process) inherent in the tariff review process. Market forces would prevent AT&T from pricing any of the noncore offerings above the level of core services and the volume of usage. Users would compare the cost of AT&T's non-core offerings with the cost of the core service at their levels of usage and would only choose the noncore if it was cheaper or had better service characteristics than the core offering.

The price ceiling would also effectively limit AT&T's ability to engage in predatory pricing. For that to be profitable the predator must be able to raise its prices once it has driven its competitors from the market. Only in this way will it be able to recoup the losses it incurred during the period of below-cost pricing. But if there is a price ceiling, AT&T would not be able to raise its prices to reap the benefits of predation, so it would have no incentive to engage in predation.

Finally, the proposal would eliminate the problem of cross-subsidization between regulated and competitive markets. This is a problem caused by regulation. Without rate-of-return regulation AT&T would have no incentive to engage in cross-subsidization, which occurs because regulation limits the profits that may be earned in some activities but not others. Under rate-of-return regulation a firm has an incentive to make it appear that profits earned in the regulated activities were earned by the unregulated ones. It may do this either by charging costs of the unregulated activities to the regulated ones or by crediting revenues earned by the regulated activities to the unregulated ones. If there is no absolute regulatory limit on the amount AT&T may earn in any of its activities, AT&T would have no incentive to do this.

Concluding Remarks

We believe we have described a "better way" in this paper. Specifying a better way is not the same as effecting one, although it might be a step in that direction. The British have adopted a variant of the approach we have outlined. The "problem" they now confront is that British Telecom has lowered its costs substantially and is earning high profits. These profits "look bad" even though they represent a freeing up of resources to produce other sources of consumer welfare.

One proposal now being considered by the British is to "look at" the regulated firm's profitability periodically. If profits are judged to be "too high," then the price ceilings might be lowered. The problem with this approach is that it might stifle the innovative or economizing activity that is responsible for lower costs or more effective performance in the first place. It puts the benefits of such activity at risk. If society merely substitutes one form of profit regulation for another, it will necessarily sacrifice much of the benefit of getting rid of profit regulation. There are no eggs if one kills the goose.

Notes

1. Under terms of the MFJ, most telephone customers in metropolitan areas (that is, most customers) now receive equal access to all long distance companies. Customers in more rural areas will receive equal access as the necessary equipment is installed in the future. See a later section for additional discussion of equal access.

2. United States v. AT&T 558 F. Supp. (D.D.C. 1982) at 173. In addition, note that AT&T's control of local bottleneck facilities was the (sole) reason the FCC itself cited for classifying AT&T as a dominant carrier in its Competitive Carrier proceeding.

3. Some of AT&T's competitors have suggested that AT&T cannot be deregulated until its market share falls to some proscribed level. That suggestion is transparently self-serving. As Professors Kaeserman and Mayo have noted, "if changes in public policy must wait for the OCCs to announce that they are ready to compete openly without regulatory favoritism, then the current system will undoubtedly endure for a very long time indeed." See "Market Based Regulation of a Quasi-Monopoly—A Transition Policy for Telecommunications," Policy Studies Journal (forthcoming); see also David Kaeserman and John Mayo, "The Ghosts of Deregulated Telecommunications: An Essay by Exorcists," Journal of Policy Analysis and Mani-
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Agreement 6 (Fall 1986). The reader should note that we are advocating revisions rather than removal of regulatory controls at this time.

4. This is not to suggest that competition has become fully or adequately effective. Yet, competition has certainly become more effective in recent years than it was before. And if the current level of competition were sustainable over the long run (an open question in our view), this market would be just as effectively competitive as several other unregulated markets in the economy.

5. In a frequently cited academic journal article, Paul MacAvoy and Kenneth Robinson draw the same conclusion. See "Lossing to Judicial Policymaking: The First Year of the AT&T Divestiture," Yale Journal on Regulation 2, Number 2 (1985): 1-42.

6. See Multinational Business Services, Inc. / Past Marvick, "Cost Analysis of Telecommunications Regulation," The figure for total direct costs was computed from the combined estimated costs of the FCC and all interveners except AT&T. Interveners included competitors in the telecommunications industry, industry users, state and local governments, and others. While this study's estimates of potential cost savings are premised on reforms that differ from those we recommend, we nevertheless believe that they provide a reasonable estimate. Indeed, because AT&T's potential cost savings are excluded, because estimates are based on direct rather than relevant opportunity costs, and because our suggested revisions are likely to generate even greater cost savings, this study's range of estimates should, in our opinion, be viewed as lower bounds for actual cost savings likely to be experienced.

7. The theory of the government's relief in United States v. AT&T was to separate the competitive elements of the telephone system from the monopoly ones. The monopoly elements are located in local exchange operations, which continue to be regulated. But there has been no deregulation of the presumptively competitive long-distance sector, despite divestiture and equal access.


10. If monopolizing behavior were legal, that would encourage wasteful resource investments in acquiring monopoly power.

11. In unregulated markets prices are determined by supply and demand, and increases in supply relative to demand may cause prices to fall below individual firms' book costs. That leads naturally to equilibrating reductions in supply. Regulatory attempts to prevent prices from falling below (measures of) costs may lead to further increases in supply and eventually to even greater downward pressure on prices. They are thus likely to be wasteful and self-defeating.


13. Besides being incompatible with the use of competition as a discovery procedure, continued rate-of-return regulation may also be incompatible with the natural evolution of a competitive market structure. For example, if there is regulatory failure and AT&T is not permitted to earn a competitive rate of return, that will effectively exclude all rivals who are not more efficient than AT&T. And that problem will be exacerbated if new entrants must pay a premium for capital because their capacity to produce profits is unproven and, therefore, possibly risky.


15. See ibid., p. 945.


20. See Kwerel and McNally, "Promoting Competition," pp. 61-64.


22. This estimate does not take into account the fact that some customers have multiple lines.


Deregulation of Local Exchange and Its Interaction with Access Charges: The Search for an Optimal Rate Structure

Alan Baughcum and Brian Sullivan

At the October 1986 U.S. Telephone Association (USTA) conference, FCC Chairman Fowler identified the objective of the FCC as serving the public interest. This translated in his view to the goal of a free, unregulated marketplace for telecommunications products and services. Such a marketplace generates superior results with respect to prices, quality, diversity of choice, and technological improvement over alternative forms of industrial organization dependent on some sort of government regulation. The goal (implicitly the FCC's) of economic efficiency is best achieved in short with a minimum of government involvement, yet much of the regulatory activity at the FCC continues to focus on setting rates, including access rates, to achieve these benefits.

Note: The opinions expressed are those of the authors only and not necessarily those of R. W. Beck and Associates.

As might be expected, regulation varies widely across the states. Connecticut has adopted a moratorium on intrastate toll competition, while Nebraska has dropped entry barriers and most direct regulation altogether. In both cases these policies were adopted to achieve the benefits of economic efficiency. In most states, regulation is intermediate between these two models, with much regulatory effort focused on setting rates to achieve the benefits of economic efficiency.

Purpose of This Paper

This paper is an out-growth of a study completed for the Colorado Public Utilities Commission (CPUC). In that research the authors examined the telecommunications environment in Colorado and constructed simulation models to assess the effect of changing environmental variables on the demand for local telephone service (universal service) and switched access service. Of the array of factors examined, we concluded that the two deserving the greatest attention by the CPUC were a sudden increase in the level of competition directed at the local exchange carriers and continued maintenance of high carrier common line charges. For the most part, the latter represent a tax levied on switched access service. In this paper we analyze this "tax" using the traditional literature on taxation and the general welfare. A sudden increase in competition is harder to characterize. After struggling with the issue, we tentatively concluded that this best can be viewed as changing equilibrium in factor markets.

We scanned the environmental trends now characterizing the reality against which telecommunications is regulated in Colorado. These trends were continued technical advance, federal efforts aimed at deregulation, international competition stressing cost cutting rather than pricing to gain profitability, the growth of the information age, and the need for Colorado clearly to articulate telecommunications policy goals. Of these, technical advance, cost cutting, and the growth of the information age are changing cost structures and producing a growing competitive attack on local carriers. Put another way, these three trends are causing disruption in markets for factors of production. As factor markets regain equilibrium, telecommunications demand and supply are altered. To the extent telecommunications becomes an avoidable cost, competitive pressure on the local carriers grows.
Our research in Colorado concluded that there was no painless way to migrate from the present to a future characterized by market forces being in control. This paper examines telephone and utility pricing issues expressly accounting for adjustment in factor markets. By so doing, it may be possible to recast the issue of winners and losers in less pejorative terms than we found possible in our Colorado analysis.

Our purpose is to compare two alternative traditions of economic orthodoxy and then to discuss how these can be used to analyze the deregulation of local exchange and local access markets. It is no secret that economists have their disagreements, mostly due to the fact that economics is an evolving social science. As such, it seeks to explain economic phenomena by use of simplifying assumptions, which are used to construct models "refutable" by data. Each time an assumption is made, certain real-world phenomena are assumed away. The progress of thought then relies on empirical refutation of the alternative simplifying models, which themselves are the logical consequences of necessary but limiting assumptions. The process of empirical refutation then becomes one of identifying "safe" assumptions from "dangerous" ones. This can be a time-consuming process and require the expenditure of enormous analytical resources. For example, the noted economist E. H. Chamberlin first introduced his theory of monopolistic competition in 1933 in an attempt to offer an alternative to pure monopoly and pure competition. In later editions to his book, Chamberlin updated the bibliography in his 1933 work. He stopped this practice upon reaching 1,497 entries as of 1956. Between 1948 and 1956 Chamberlin counted 806 titles published in the topic of monopolistic competition.

In contrasting partial equilibrium analyses and general equilibrium analysis, each a topic of wider scope than Chamberlin's contribution, we seek to share with others in the telecommunications economics and policy field our reflections on two alternative economic models available to the policy maker. The implications of the models are different, so different that logic would seem to dictate that at least one is wrong.

It is a sign of an intellectually healthy climate in the economics profession that different policy models can be presented and discussed. It is in this spirit that we offer this discussion. We claim no originality as to theoretical content. We do hope that we can spark some discussion as to alternative foundations for regulatory policy and thus make a contribution to our colleagues. Finally, we do conclude that given the alternative analytic framework to be explored, the policy-oriented economist might be a little more humble in stating policy preference. No doubt, we ignore this admonition in our concluding paragraphs.

The main themes of this paper are twofold. First, most of the telecommunications pricing literature is based on partial equilibrium analysis. Within those confines, the conclusions of this literature do indeed flow, as a matter of economic logic, from the premises. The difficulty from a policy point of view is that the requirements of partial analysis, namely, de minimus secondary effects flowing from a reallocation of resources within the industry under analysis, are likely to be wrong in the case of telecommunications (and probably for most regulated industries).

Second, this paper relies heavily on a tool not often used in telecommunications pricing literature, the two-factor, two-commodity general equilibrium model. Many principles of the theory of modern international trade and of taxation are easily derived from such a model. There is clearly international telecommunications competition in services as well as equipment. Moreover, the ongoing debate focusing on "cross-subsidy" of services within the regulated telecommunications industry parallels the direct-indirect taxation debate of earlier years. The cross-subsidy issue can be analyzed as an application of the international trade literature regarding the welfare effects of tariffs or, even more directly, as an application of the literature regarding direct versus indirect (excise) taxes.

This paper demonstrates that regulatory pricing solutions based on partial equilibrium analysis, whether first-best or second-best, cannot be demonstrated to be improvements in economic efficiency for the case when the regulated industry is large relative to total national income. General equilibrium analysis for large industries is required for examining the effects of major price or market changes. It is, in fact, demonstrable from general equilibrium analysis that partial pricing solutions such as Ramsey prices may not lead to improvements in efficiency in such instances.

With partial equilibrium solutions inapplicable, and with the information required by general equilibrium models shown to be many times larger than the available data, regulatory commissions
are ill-advised to continue an analytical search for the optimal rate structure. Given that telecommunications markets are becoming more competitive, it seems reasonable to rely on market forces and not "optimal" regulatory pricing schemes for improvements in economic efficiency.

Partial Equilibrium Analysis

Definition and Application

Partial equilibrium analysis focuses on "a single market. The demand and supply of a single commodity are conceived of as functions of the price of that commodity alone." Such analysis is justified if and only if changes in the price of the good or service under examination leave relative prices in all other markets (labor, capital, other goods and services, and so forth) unchanged.

All the traditional and recent literature with which we are familiar employs partial equilibrium analysis. Alfred Kahn's two volumes on the economics of regulation, Hotelling's analysis of market organization and infrastructure investment, the Averch-Johnson literature, Ramsey pricing theorems, and the contestability literature all employ partial equilibrium analysis. The conclusions of this literature rest squarely, therefore, on the assumptions underlying partial analysis (as well as other assumptions specific to the particular study).

Key Assumptions

The basic assumption is that analysis of a single market is justified if there are only de minimus effects on supply and demand conditions in other markets. Given the importance of regulated industries in the U.S. economy, this assumption seems strained. Telephony alone accounts for about 3 percent of GNP. When other utilities are included, utility pricing and regulation affects nearly 10 percent of GNP.

To anticipate our argument, a general equilibrium model shows the determination of equilibrium in both product and factor markets. The share of telecommunications and of all public utilities (including telephone) in GNP speaks to the significance of these industries in product markets. It is frequently argued that utilities are capital intensive. This being the case, they would be an even larger industry in the capital "factor market" than they

are in the product market. Table 1 uses illustrative data on U.S. capital markets and shows the significance of the utility industry in this context. No special significance should be attached to any single number, but the range clearly suggests that for the capital market the assumption of de minimus secondary effects is very restrictive.

Table 1. Percentage Share of Telecommunication and All Utilities in Various Economic Aggregates

<table>
<thead>
<tr>
<th>Economic aggregate</th>
<th>Telecommunications (Percent)</th>
<th>All utilities (Percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross fixed capital stock (1981)&lt;sup&gt;a&lt;/sup&gt;</td>
<td>2.7</td>
<td>7.5</td>
</tr>
<tr>
<td>Gross fixed business capital stock&lt;sup&gt;b&lt;/sup&gt;</td>
<td>3.9</td>
<td>10.8</td>
</tr>
<tr>
<td>SEC issuance of securities (1983)&lt;sup&gt;c&lt;/sup&gt;</td>
<td>5.3</td>
<td>17.6</td>
</tr>
<tr>
<td>SEC issuance of securities (1984)&lt;sup&gt;d&lt;/sup&gt;</td>
<td>2.4</td>
<td>10.7</td>
</tr>
<tr>
<td>Plant and equipment spending (1984)&lt;sup&gt;e&lt;/sup&gt;</td>
<td>7.6</td>
<td>21.0</td>
</tr>
<tr>
<td>Plant and equipment spending (1985)&lt;sup&gt;f&lt;/sup&gt;</td>
<td>7.1</td>
<td>19.4</td>
</tr>
</tbody>
</table>


<sup>b</sup>Survey of Current Business (December 1985), Table S-19.

<sup>c</sup>Survey of Current Business (December 1985), p. 35.

Problems with Partial Equilibrium Analysis

The basic assumption of de minimus secondary effects leads to several problems.

1. The absence of a market for capital assets leads to confusion about the nature of the analysis, whether it is short run or long run in nature, and also to confusion about the distinction between the two "runs." (2) Supply and demand conditions are taken as given, with inadequate attention paid to factor markets, production conditions, or the role of technology. Specifically, the relationship between factor incomes and product demand functions is ignored entirely. (3) An initial resource allocation is taken as given. Changes in resource allocation caused by price changes in the market will result in altered resource allocations difficult to identify or characterize (as beneficial or harmful).
One important example of generally accepted principles regarding telecommunications pricing is Kahn. Consider his introduction to short-run versus long-run marginal cost pricing.

It is a familiar and elementary proposition in economics that sunk costs are and should be irrelevant to short run pricing and output decisions. The only cost relevant in deciding how much to produce in plants already constructed, with production capacity already installed are the variable costs of operating the plant, farm, or service establishment already equipped.

The longer the time perspective of the costing process, the greater the proportion of costs that become variable. As existing plant and equipment continue to operate over time, they will ordinarily involve higher and higher variable costs of shutdowns, repair and maintenance, and wastage of labor and materials. Meanwhile, the progress of technology will ordinarily make increasingly attractive alternatives available. Eventually, therefore, the question of replacement will arise. At some time, the business, in determining whether or not to continue to practice and if so on what scale, will be able to decide once again whether to incur some or all of the capital costs of production. He will find, that is, that these costs—fixed in the short run—are variable in the long run. The doctor can and should ignore those costs incurred in the past for his training, in deciding whether it is worthwhile for him to keep practicing; but each prospective medical student makes the calculation afresh in deciding whether to embark on that profession. When the competitive model prescribes prices equated to marginal costs, does it mean the incremental short run, variable cost of operating existing capacity, or intermediate-run cost, which will include also the prospectively mounting cost of repair, and maintenance and operation, or the long-run costs of ultimately renewing, replacing or adding to capacity? Are the optimum medical fees what it takes to induce doctors already trained to continue offering their services or what it takes to bring in a fresh supply of new doctors?

Kahn’s questions reveal the confusion inherent in the Marshallian paradigm of short run versus long run. The balance of Kahn’s discussion goes on to present problems relating to the identification of the class of utility ratepayers who cause the utility to require new capacity. This seems to be a search for a class of people who consume in the long run versus those who consume in the short run. It is no wonder that, under such economic assumptions, rate hearings have become so litigious and acrimonious.

Part of the confusion arises from the fact that economic terms such as short run and long run refer to the degree to which factors are variable rather than chronological. That is, they refer to alternative frames of reference. Also, the dichotomy ignores the existence of resale markets (such as securities exchanges) for assets. With securities exchanges, businesses in need of capacity can buy those assets. Recent merger and acquisition deals in transportation, energy, and telecommunications have shown this to be the case.

Rigid adherence to the restrictive assumptions of partial equilibrium analysis and misinterpretation of the short-run and long-run dichotomy can lead to policy decisions such as one now being considered in Florida. Evidently, developers are on the verge of persuading the Florida legislature to grant development rights to thousands of acres of land in communities to be served by a high speed train because “a bullet train probably would earn an operating profit once it was built. But revenue from the fare box wouldn’t be enough to pay off the massive debt incurred during construction.”

This problem is reminiscent of the Hotelling example of the bridge and optimal tolls. If a bridge can be assumed to exist, the optimal toll may be zero. If no bridge exists, its construction needs to be funded. Whether the construction is funded by tolls, the social diversion of resources away from alternative uses is the same. These resource owners expect to be compensated.

Consider how the existence of asset markets solves the problem. An asset, such as an airplane or railroad rolling stock, has a current cost of production. In the case of these two types of assets, active rental markets also exist. The resale price of an airplane or boxcar is then a function of its rental rate, for the asset competes with other income-producing assets for a position in investors’ portfolios. The airplane or boxcar manufacturing industry expands or contracts depending on the resale price of the asset relative to the marginal cost of producing that asset. Thus, the marginal cost of freight shipment, by air or rail, fully incorporates the compensation required for the so-called fixed asset. This must be true because asset rental rates and asset exchange prices are determined in the same general equilibrium process.

The bridge example may therefore be seen as more of a problem of the institutional underpinnings of transportation supply.
Unlike the airline or railroad case, bridges are constructed by private firms but owned by public agencies. If a private market existed for equity in bridges, highways, and so forth, then there is no reason to believe that pricing would be inferior (from an economic efficiency point of view) to pricing for airlines or deregulated telecommunications services. The link between short run and long run would be provided by the (missing) market for equities in bridges.

Production Conditions and the Role of Technology

Several economic assumptions support the two-factor, two-commodity general equilibrium model. Differences between that model and the more typical partial equilibrium model are compared and contrasted in Table 2.

Table 2. Partial and General Equilibrium Assumptions

<table>
<thead>
<tr>
<th>Topic area</th>
<th>Partial model</th>
<th>General model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of relative prices</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Number of explicit production functions</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Factor prices</td>
<td>Exogenous</td>
<td>Endogenous</td>
</tr>
<tr>
<td>Aggregate factor supply</td>
<td>Fixed</td>
<td>Fixed or variable</td>
</tr>
<tr>
<td>Factor allocation</td>
<td>Exogenous</td>
<td>Endogenous</td>
</tr>
<tr>
<td>National income</td>
<td>Exogenous</td>
<td>Endogenous</td>
</tr>
<tr>
<td>Commodity market equilibrium</td>
<td>Endogenous</td>
<td>Endogenous</td>
</tr>
<tr>
<td>Returns to scale</td>
<td>Usually unspecified</td>
<td>Often homogeneous of degree one, other cases can be considered</td>
</tr>
<tr>
<td>Joint products</td>
<td>Possible</td>
<td>Possible</td>
</tr>
</tbody>
</table>

Resource Allocation: The "Incidence" of the Excise Tax and Cross-Subsidy

In telecommunications, the issue of cross-subsidy is generally taken to refer to adverse policy consequences in two arenas, antitrust and incidence. It is with the second issue that we deal in this paper. The concept of the incidence of a cross-subsidy is readily understood if the cross-subsidy itself is broken into two parts, a tax on good X, the proceeds of which are used to finance a negative tax (or subsidy) on good Y. The taxes and subsidies can be seen as deviations of service prices from the appropriately defined incremental cost. The "incidence" of a tax falls on the persons who ultimately pay it. The "impact" of a tax refers to the person to whom the taxing authority turns to collect the tax. While it is often the legislative intent that the incidence and impact reside with the same person, the process of tax "shifting" often separates the two. 13

The thrust of the following discussion is to contrast tax incidence theory in the partial equilibrium analysis case and the general equilibrium analysis case. The main conclusion from partial equilibrium analysis is that the incidence of an excise tax is split between "consumers" and "producers." By contrast, in general equilibrium analysis, an excise tax is a "wedge" that is driven between the aggregate paid for the output of an industry and the aggregate of factor receipts of the productive factors employed in that industry.

The usual treatment of the incidence of a cross-subsidy is as follows: The services provided under tariff to customer class A are priced above cost so that services provided to class B may be priced below cost, with the regulated firm earning some predetermined rate of return. It therefore is alleged that B receives a subsidy at the expense of A. Local exchange carriers might characterize A as being business customers and B as residential customers. Some regulators might characterize A as monopoly ratepayers and B as customers of competitive services.

Using the residence/business dichotomy for a moment, somewhat more enlightened analysts will take the argument one step farther and argue that business costs are passed on to residential consumers. Therefore, in the final analysis the impact of the tax is on business but the incidence is on residence customers. This is
commodity and factor prices, are determined simultaneously. Relative prices then determine the allocation of factors of production to each industry and the distribution of the output of the industries among owners of factors. In a general equilibrium framework, households sell factors of production (or factor services) and buy the outputs produced by the various industries. Each economic agent is simultaneously a seller and a buyer. Thus, the consumer/producer dichotomy of partial equilibrium analysis is meaningless in this framework.

**Example: The “Incidence” of the Excise Tax and Cross-Subsidy—Once Again**

What if the industry depicted in Figure 1 is large relative to the economy as a whole? Total value added in all aspects of telecommunications is about $100 billion per year and therefore is about 3 percent of current nominal U. S. GNP. In such a case, the reduction in quantity demanded from $Q_0$ to $QT$ must entail a substantial amount of unemployment for some factor of production. Unless we are to assume that prices in all factor markets are fixed, Figure 1 is silent as to how such a large industry, and hence the economy, adjusts to this displacement of output.

Figure 2 employs the familiar convex production possibility frontier between goods $X$ and $Y$ to illustrate the effect of an excise tax levied on $Y$. Point $A$ is the pretax equilibrium, and the line $ST^*—ST^*”$ shows the equivalence between the marginal rate of substitution of $X$ for $Y$ and the marginal rate of transformation of $X$ for $Y$. This is the well-known first-best condition of general competitive equilibrium. Suppose the system is disturbed by the imposition of an excise tax on $Y$. The relative price of $Y$ rises, and “consumers” maximizing utility are now confronted with a price line shown as $SS’$. Buyers forgo some of $Y$ and attempt to substitute in favor of $X$.

What mechanism encourages producers to increase production of $X$? The answer lies in the adjustment of factor prices. Factors of production employed in industry $Y$ now exhibit a lower value of marginal product. Since the strict convexity of the production possibility frontier is due to the use of differing factor intensities in the production of $X$ and $Y$, if these were produced under conditions of identical factor intensity, the frontier would be a straight line.

**General Equilibrium Analysis**

**Definitions**

A general equilibrium model is one wherein all prices, both
In the process of seeking alternative employment, the factor used intensively in the production of $Y$ will experience a decrease in its relative wage rate (or rental rate). The share of that factor in national income will fall. It is in this sense that an excise tax may be viewed as a "wedge" driven between the price paid and the income received by the aggregate of the factors of production. This wedge shows up in Figure 2 as the difference between the marginal rate of substitution of $X$ for $Y$ (shown by the line $SS'$) and the marginal rate of transformation of $X$ for $Y$ (shown by $TT'$). At the new equilibrium point, $B$, the factor of production specialized in $X$ experiences a net increase in demand for its services, and that factor enjoys a higher share in national income.

We note in passing that since both $A$ and $B$ are on the production frontier, there is insufficient data in Figure 2 to determine whether there has been a net change in real national income. However, it is clear that households providing the services of the factor of production used intensively in producing $Y$ are bearing the incidence of the tax. Even if they consume $X$, by virtue of their relative intensive ownership of the factor used intensively in $Y$, their share of national income is decreased.

Now suppose $Y$ is used by business. To the extent that a class of households own the factor used intensively in the production of $Y$, that class is harmed. Since no unambiguous statement can be made regarding the change in national income, it is impossible to make any judgments about the relative well-being of the "residential" sector since the residential sector is the ultimate owner of all the factors of production. This point has been made long ago in the theory of taxation by E. R. Rolph and G. P. Break, who concluded:

"Thus a heavy tax on high-quality fur coats has some income-reducing effect on those engaging in their production; and if these groups are poor, as many in fact are, they are placed at a further disadvantage as compared with other groups in the population. The cases in which excise taxes, therefore, can be justified with respect to both their allocation and income effects are not likely to be numerous."  

**Summary and Conclusions**

The assertion as to the existence of a cross-subsidy and its incidence in telecommunications regulatory proceedings, is seen to be based on unspoken assumptions with regard to adjustments of factor prices as well as differing factor intensities. We have also shown that use of partial equilibrium analysis produces incomplete and often misleading answers. Assertions that either residence or business receive any subsidy are both unfounded and meaningless in the context of even a simple general equilibrium framework. Therefore, such assertions are of little if any value in assisting
policy makers to formulate decisions to advance the overall level of economic efficiency.

Problems of Optimal Rate Structures

This section explores the problem of optimal rate structure from the partial and general equilibrium points of view. The partial equilibrium result is only asserted in this paper. Its analytic development is widely available, some of which sources this paper cites; others, equally valuable, are also available. The general equilibrium results are developed more fully here because of the absence of these results in the body of telecommunications economics and policy literature.\(^{19}\) We stress, however, that the general equilibrium development is "as orthodox" in the broader economic literature as are partial equilibrium results. Most policy conclusions developed by economists pertaining to free international trade can only be derived in a general equilibrium framework. Given the growing importance of international trade in telecommunications, products, and services,\(^{20}\) the absence of general equilibrium analysis in telecommunications policy is regrettable.

Deviations from First-Best: Ramsey Pricing

The advocacy of Ramsey pricing suffers from two of the confusions in partial equilibrium analysis.\(^{21}\) These are the confusion between short- and long-run marginal cost pricing as well as the apparent nonresponse of factors of production in the face of Ramsey excise taxes. We will refer to Ramsey excise taxes rather than Ramsey prices because it is the markup or tax above marginal cost that is to be determined using the inverse elasticity rule. Consider the way one recent treatment of inverse elasticity pricing is introduced.

"Our previous discussion leads us to the analysis of the efficient prices which cover the total costs of the regulated firm. Because the break-even constraint prevents the imposition of the fully optimal, so-called first best, marginal cost prices, we refer to prices which maximize total surplus subject to breaking even as optimal second best prices."\(^{22}\)

This section will show that the appropriateness of the Ramsey excise tax rule\(^{23}\) is limited because it is based on the restrictive assumptions of partial equilibrium analysis.\(^{24}\) Accepting, for the moment, the viability of summing consumer and producer surplus, the Ramsey excise tax rule also suffers from the outmoded concept of "excess burden" developed in partial equilibrium tax analysis. Finally, once it is admitted that factors of production will adjust to the new tax situation, the viability of observable consumers' surplus and producers' surplus upon which Ramsey pricing relies can be called into question.

Ramsey's original contribution to the taxation literature was set in the environment of the concepts of excess burden and equal sacrifice. These had the measurability of utility as well as interpersonal comparisons as starting points. Excess burden is defined as the loss in consumer welfare that results from disturbing a closed economy with an excise tax. Excess burden thus leads to focusing on the equilibrium of a single consumer or groups of consumers. The concept of equal sacrifice pertains to the "equitable" sharing of the excess burden of a tax among all economic agents. In a two-factor, two-commodity world, the excess burden of a system of excise taxes could be minimized if (so the argument goes) the ratio of consumers' observed consumption of X to the consumption of Y is left unchanged by the taxes. With regard to telephone services this is clearly the objective sought by advocates of Ramsey excise taxes. We note, however, that in the telephone case the pretax equilibrium is not the same as the current ratios of consumption of various telephone services. Instead, the pretax point is the one at which all services are priced at marginal cost.

Hotelling did not advocate excise taxes at all.\(^{25}\) The point of his article was to show that the general welfare was optimized by use of income taxes to subsidize losses of utilities where rates are set at short-run marginal cost. Hotelling's elaborate proof of the optimality of direct taxes was rebutted by Little, reproduced verbatim, with the aid of Figure 3.\(^{26}\)

The usual analysis of direct versus indirect taxation (or subsidization) runs typically as follows: A single "economic man" who spends his income on two goods (one of which may be "money") is assumed. In Figure 3, \(Q_0\) is the equilibrium tax-free position. When an income-tax equal to \(AB\) of \(X\) is imposed, \(Q_1\) is reached. The same sum could be raised by an indirect tax on \(Y\), which would result in a position such as \(Q_2\). From the usual convexity assumption it follows that \(Q_2\) is worse than \(Q_1\). Q.E.D. At first sight this result always looks like a conjuring trick. There is no overt reference to marginal
costs. Yet it is well known that nothing can be proved without some such reference.

The difficulty with the case for direct taxation is the assumption that factor supplies are completely inelastic with respect to the rate of income taxation. The value of Little's article is that it drives home the point that for any analysis of optimal taxation to hold water, specific account must be taken of factor as well as product markets.

Figure 4 reproduces the production possibility frontier of Figure 2. Again, the strict convexity of the production possibility frontier stems from the fact that the two commodities (X and Y) are produced by different ratios of capital and labor at the prevailing wage/rental ratio. The point B in Figure 4 is the point where, in the absence of taxation and the presence of competitive factor and product markets, the marginal rate of substitution and the marginal rate of transformation are equal, thus creating a first-best general equilibrium. Ramsey excise taxes are then imposed which drive the economy to a new point, C. Following the Ramsey logic, C must be in the interior of the production frontier. To point to C as the final resting place is to assume away any and all capability of factor markets to adjust.

Figure 5 can be employed to highlight why C is an untenable point in Figure 4. The first-best solution, B in Figure 4, is labeled in Figure 5. As expected, B lies on the contract curve (highlighted) formed by the tangencies of the various X and Y isoquants. Points C* and C' are drawn in Figure 5 to correspond to the equipropor-
identical to the marginal rate of transformation at point \( B \) of Figure 4, the new equilibrium would be away from point \( B \) but on the frontier. Clearly, the new equilibrium would be away from the feasible portion of the ray \( OA \) of Figure 4, the ray required and alleged to be optimal under the Ramsey rule.

It is readily apparent from Figure 4 and 5 that the preferred tax structure is \( \textit{ad valorem} \) and not inverse elasticity.28 The \( \textit{ad valorem} \) tax must also apply to "leisure." This is hard to do in a market economy, where leisure does not have explicit price.

\section*{Comparisons of Rate Structures: Information Problems}

Consider the ability of economists to measure consumers' and producers' surplus. Measurement of producer surplus requires the measurement of marginal cost functions.

This section reaches two conclusions: (1) Accounting cost data are constructed to answer questions which are not of an economic nature. Accounting costs show cost categories per unit of calendar time, not costs as schedules against output. (2) The presence of significant deviations from competition renders the use of partial equilibrium welfare analysis (such as producers' or consumers' surplus) an invalid tool for measuring welfare changes.

There appears to be widespread agreement that standard accounting data do not measure costs in a fashion suitable for use in empirical analysis of an economic theory.29 Interfirm differences in accounting practices makes the building of industry data more difficult.29 Accounting data are generated to present the financial picture of an enterprise at a given time. By contrast, economic costs are usually treated as a schedule or a function, as in Eq. (1).

\[ C = C(Y; p) \]  

(1)

\( C \) is the dual cost function from which standard average and marginal cost curves can be derived. \( Y \) is the output or vector of outputs of the firm, and \( p \) is the vector of factor prices. Accounting data do not purport to set up a schedule as in Eq. (1), but to show costs incurred over time.

Development of empirical versions of Eq. (1) therefore present a host of econometric problems to the data analyst. Yet, empirical estimates of Eq. (1) are necessary if the policy analyst is to hope to achieve a measurement of the standard welfare triangles (particularly producers' surplus).
identical to the marginal rate of transformation at point B of Figure 4, the new equilibrium would be away from point B but on the frontier. Clearly, the new equilibrium would be away from the feasible portion of the ray OA of Figure 4, the ray required and alleged to be optimal under the Ramsey rule.

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Consider the ability of economists to measure consumers’ and producers’ surplus. Measurement of producer surplus requires the measurement of marginal cost functions.

This section reaches two conclusions: (1) Accounting cost data are constructed to answer questions which are not of an economic nature. Accounting costs show cost categories per unit of calendar time, not costs as schedules against output. (2) The presence of significant deviations from competition renders the use of partial equilibrium welfare analysis (such as producers’ or consumers’ surplus) an invalid tool for measuring welfare changes.

There appears to be widespread agreement that standard accounting data do not measure costs in a fashion suitable for use in empirical analysis of an economic theory. Interfirm differences in accounting practices makes the building of industry data more difficult. Accounting data are generated to present the financial picture of an enterprise at a given time. By contrast, economic costs are usually treated as a schedule or a function, as in Eq. (1).

\[
C = C(Y; p) \tag{1}
\]

\(C\) is the dual cost function from which standard average and marginal cost curves can be derived. \(Y\) is the output or vector of outputs of the firm, and \(p\) is the vector of factor prices. Accounting data do not purport to set up a schedule as in Eq. (1), but to show costs incurred over time.

Development of empirical versions of Eq. (1) therefore present a host of econometric problems to the data analyst. Yet, empirical estimates of Eq. (1) are necessary if the policy analyst is to hope to achieve a measurement of the standard welfare triangles (particularly producers’ surplus).
Consider a two-input \((X_1, X_2)\) and a two-output \((Y_1, Y_2)\) economy. Assume the economy is private and closed. Technology is specified by twice continuously differentiable transformation:

\[
F(Y_1, Y_2, X_1, X_2) = 0. \tag{2}
\]

Finally, let factor markets and the product market for \(Y_1\) be competitive; \(Y_2\) is a monopoly not subject to price regulation. Profit maximization on the part of the monopolist leads to a level of output for \(Y_2\) that is less than economically efficient. Now suppose Eq. (2) is such that

\[
\left( \frac{X_1}{X_2} \right)_{Y_1} > \left( \frac{X_1}{X_2} \right)_{Y_2} \quad \text{for all} \quad (Y_1, Y_2) \quad \text{on the surface of} \quad F(\cdot). \tag{3}
\]

Eq. (3) merely states that input \(X_1\) is imperfectly specialized to produce \(Y_1\), and \(X_2\) is also imperfectly specialized to produce \(Y_2\). Competitive factor markets require that factor prices of \(X_1\) and \(X_2\) adjust to achieve full employment. Now since \(X_2\) is specialized to \(Y_2\), the observed competitive factor price of \(X_2\) is lower than its economically efficient level. Likewise the price of \(X_1\) is above its economically efficient level, and the level of output of \(Y_1\) is also above the economically efficient rate. Thus, in this case the presence of monopoly distorts the level of factor prices determined in competitive factor markets. These in turn lead both producers of \(Y_1\) and \(Y_2\) to produce at nonoptimal rates. Where factor prices are thus distorted, it is not feasible to use observed factor prices as the basis for estimating cost functions upon which judgments about welfare changes in a Pareto-optimal economy are to be made. In an economy experiencing severe deviations from workable competition, the development of \(C(Y; p)\) schedules for telecommunications appears to be a forlorn task.\footnote{Ehrenberg, 1969}

Having disposed of observing producers’ surplus, one need only be reminded that factor incomes, and factor shares in national income, are large determinants of demand curves and hence consumers’ surplus. We are exactly wrong if, in the name of economic efficiency, we optimize consumers’ surplus using demand curves determined without regard to the knowledge that the underlying resource allocation is, in fact, optimal.

---

**Exchange and Access Charges: Deregulation**

This section addresses the implications of the deregulation of local exchange using a modified general equilibrium model. First, recall the partial equilibrium conclusions: (1) Because local exchange is priced below cost, residential and possibly business rates would rise; (2) deregulation of exchange access would raise costs to interexchange carriers, according to them, as local companies seek to cross-subsidize their competitive operations; and (3) the cost squeeze would induce a contraction of the interexchange industry. This scenario assumes the presence of substantial monopoly power on the part of the local exchange carriers. This last assumption will be carried forward. The authors recognize that the assumption is debatable.

As stated in the partial equilibrium case, it would appear that only the residents of Nebraska, the irresponsible, or the current FCC chairman would advocate such deregulation.\footnote{McGahan, 1973} Nevertheless, partial equilibrium suggests that both local exchange and interexchange would be curtailed. What are the effects on the balance of the economy and on factor incomes? The next section takes up these questions.

**General Equilibrium Analysis**

Exchange services are produced for direct sale to end-users and to other telecommunications firms who use exchange services (local access) in the production of other services (say, toll). Suppose both exchange and toll are completely deregulated. Further suppose that toll markets are competitive, but exchange is produced by a monopoly. Also suppose the exchange monopolist faces competitive factor markets for capital and labor services and that toll is not used by the exchange monopoly. Finally, suppose there is to be a third “output” produced by using capital and labor but not requiring either exchange or toll in its production function.\footnote{McGahan, 1973} Using this modified three-commodity (exchange, toll, all other) and three-factor (capital, labor, exchange) model, what are the welfare implications of a complete deregulation of exchange and toll?

At first, the removal of all ratebase regulation from exchange means that the monopolist will decrease exchange output and raise exchange prices—including access charges. The curtailment of exchange output releases capital and labor for employment in the
remaining two industries. Producers of the third output benefit unambiguously because their marginal costs are reduced owing to the decrease in both wage and rental rates that result from factor shifts in supply. The position of toll providers is indeterminate, depending on the relative cost share of exchange in their total costs. The a priori likely case is that toll providers are harmed because exchange access is likely to be a large share of costs. If this is the case, the marginal cost of toll (and by assumption of competition) rises, and the relative price of toll also rises. Capital and labor also exit the toll industry and also exert downward pressure on wage and rental rates. This further improves profitability in all other sectors, and those outputs rise further as the displaced capital and labor are reemployed.

Continuing with the example, if the shares of capital and labor are large relative to the share of exchange in national income, the reduced wage and rental rate translate into reduced demand and price for the "all other" good. The new price thus falls to its new marginal cost.

One can say little about the increase or decrease in economic efficiency unless it is argued that the pre-deregulation prices for exchange, toll, and all other were at their economically efficient levels. That is, the three pairs of marginal rates of transformation equaled the respective three pairs of marginal rates of substitution. If, as the exchange carriers maintain, exchange is subsidised by toll, then the increase in exchange prices is a step toward efficient pricing, but the higher toll rates are a step away. If exchange had been subsidising toll, then the increase in toll rates is an improvement, but the increase in exchange rates is a further departure from efficiency. Finally, one has to make a variety of assumptions regarding the relative intensities of capital and labor among the three production functions to determine whether the movement in the price of the "all other" good is an improvement or a subtraction from overall efficiency. For example, suppose both exchange and toll are capital intensive relative to the composite good and that exchange is the most capital intensive. Ad hoc empiricism suggests this to be the case. Relative to the first-best case, the subsidy to local exchange is a subsidy to capital. By the assumed factor intensities, capital's price is too high, and too much capital is employed in exchange (and possibly toll). In a world having a "capitalist class" and a "working class," the stim-

ulation of the output of the composite good increases the share of the "working class" in national income. Thus, under these assumptions regarding production technologies, deregulation may be beneficial to "consumers" and comparatively harmful to the "wealthy." All the foregoing assumes an inelastic supply of capital and labor. Little discusses the indeterminacy of the solution when factor supplies are not completely inelastic.24

Conclusions and Implications for Policy Makers

It was assumed at the beginning of this paper that the promotion of improved economic efficiency is the goal toward which policy makers are striving. If it is believed that continued government involvement in telecommunications markets is the best method of achieving this goal, then regulators face a choice between using partial equilibrium analysis and general equilibrium analysis as an aid in establishing rates, terms, and conditions of supply and in analysing the effect of relaxing barriers to entry. Partial equilibrium analysis holds the advantage of tractability and relative simplicity, but it carries the disadvantage of its highly restrictive assumptions. Among these are the assumed "smallness" of telecommunications, the failure to analyze adjustments in factor markets, and the well-defined and measurable nature of consumer surplus.

By contrast, general equilibrium analysis carries with it a very extensive data and analytic requirement. If continued government involvement is the desired choice, the authors urge that an investment be made in addressing this need. For example, we have not included increasing returns to scale or joint production in our analysis, which would be required if the general equilibrium approach is to be adopted.27

The other major approach to attaining improved economic efficiency is substantially to relax government involvement. Happily, support for this approach can be found in both partial and general analysis. The current talk-to-local subsidy combined with available econometric evidence on service demand elasticities strongly suggest that current rate structures are the antithesis of Ramsey excise taxation. By further reducing the subsidy, competition would improve economic efficiency. The general equilibrium approach would also urge greater reliance on competitive forces as a way to drive marginal rates of substitution and marginal rates of
transformation closer to equality. Factor mobility and factor price flexibility would aid the process.

Partial analysis tends to identify losses among classes of consumers. General analysis points to factor losses as relative factor shares change.

Our final conclusion is not that competitive markets do not work. On the contrary, we believe that they work quite well. It is the economist's explanation of these workings that is divided between partial and general models. An approach suitable for state regulators has been recommended by the authors elsewhere.\textsuperscript{28} That solution is to set a ceregulatory agenda and give state regulators the authority to implement it in the face of such traditional policy objectives as universal service. The authors argued in a study of telecommunications in Colorado that competitive conditions are developing in telecommunications markets.\textsuperscript{30} This should be further encouraged.

Notes
7. Ibid., p. 7.
10. For transportation, consider Texas Air/Eastern, in energy Chevron/Gulf, and in telecommunications CoNet/Comsat. Of course, markets for securities are not the same as markets for capital assets themselves. The difference between the two is that securities markets capitalize "goodwill."
was partly for the purpose of shifting "transit" switching for trans-
Atlantic calling from London to Paris.
22. S. J. Brown and D. S. Sibley, The Theory of Public Utility Pricing (Cam-
bridge: The University Press, 1986), p. 39, emphasis in original. This ap-
23. The recent derivations of Ramsey's result use elaborate mathematics to
maximize a line integral with respect to a vector of prices subject to a
cost constraint. C. R. Hulten, "Divisia Index Numbers," Econometrica 41 (November 1973): pp. 1017–25, has shown that such a line integral
takes a multiplicity of values if the line integral is not path indepen-
dent (that is, independent of how we get from today's prices to so-called Ramsey excise taxes). H. Hotelling, "The General Welfare in Relation to
so-called integrability conditions on the consumer surplus line integral in
his classic article. These conditions were shown to be overly restrictive by
P. A. Samuelson, Foundations of Economic Analysis, 4th Athenium print-
24. These assumptions may, in fact, be realistic in state rate cases, especially
in the smaller states. The impracticality of each state conducting a general
equilibrium analysis combined with the overall largeness of the public
utility sector as a share of national income may provide some justification
for an increased federal role. It may also justify further easing of regulation
at all levels.
25. Hotelling, "General Welfare."
26. I. M. D. Little, "Direct vs. Indirect Taxes," Economic Journal (September
1951); reprinted in Shoup and Musgrave, AEA Readings. The Chicago
School version is found in Friedman, Price Theory, chapter 3.
27. The point $C$ can be any arbitrary point on the feasible portion of the ray $OA$. This ray is constructed so that the ratio of the consumption of $X$ to the
consumption of $Y$ is the same as would be observed at point $B$, the
first-best solution.
29. The statement refers to accounting data under Generally Accepted Ac-
counting Principles (GAAP). Problems include expensing R&D and ad-
vertising costs as opposed to treating them as depreciable investments.
Telecommunications carriers utilize the Uniform System of Accounts, a
system which only adds to the difficulties normally encountered in GAAP.
30. Accounting for station connections in the early 1980s is an example. Some
states approved a flash-cut to expensing, others approved the phase-in
approach. Proposed deregulation of inside wire (ISW) will cause different
companies to treat the unamortized ISW account differently when ISW
is deregulated.
31. Cost functions of the form $C(Y; p)$ are given a rigorous treatment in R. W.
Shephard, Theory of Cost and Production Functions (Princeton: Princeton
University Press, 1970), chapter 4. The existence of the classical marginal
cost function $MC = MC(Y)$ implies that $Y$ and $P$ are weakly separable.
32. The foregoing is a general equilibrium result. See H. G. Johnson, Two Sec-
tor Model of General Equilibrium (Chicago: University of Chicago Press,
1971). This argument is also found in W. J. Baumol, Economic Theory and
33. See M. Fowler, A. Halprin and J. Schlichting, "Back to the Future: A
Model for Telecommunications," Federal Communications Law Journal 38
34. That is, toll is an end-use good. The case where exchange and toll are
two intermediate goods is analogous to a multisector growth model with
several types of capital input. See E. Barsema and A. R. Dobell, Math-
ematical Theories of Economic Growth (New York: Macmillan, 1971), for
a treatment of this case.
35. To the extent that telecommunications exhibits joint production, the con-
cept of factor intensity by service is not applicable. Furthermore, factor
intensity is impossible to estimate using balance sheet or accounting data.
Hence, as with much of general equilibrium analysis, application is dif-
ficult. However, the theory is clear and should not be ignored because of
empirical problems. Simplicit cross-subsidy claims do not address the
real world of output and factor markets.
36. I. M. D. Little, "Direct versus Indirect Taxes."
Trebing and Patrick Mann, eds., Changing Patterns in Reputation Mar-
kets and Technology: The Effect on Public Utility Pricing (East Lansing:
Institute of Public Utilities, 1984), pp. 373–90. Also, see R. Morris, "Com-
1986 suggests that the ENFIA discount and economies of scale in trans-
mision and distribution may have been responsible for the shift in relative
earnings capability between AT&T Communications and the OCCs since
1982.
38. A Study of Intrastate Telecommunications Including the Means Available
To Enhance Intrastate Telecommunications Competition (1988), submitted
to the Colorado PUC, see Chapter 13.
39. M. A. Baughcum, B. P. Sullivan, and N. H. Hughes, "A Study of Bypass

Comments

Del C. Shull

These papers have provided us with thoughtful views regarding the dynamic telecommunications industry. Alan Baughcum and Brian Sullivan reviewed a deregulatory agenda with strong state regulatory oversight; John Haring made a case for a new regulatory framework for AT&T; Lee Selwyn questioned the real value of equal access and the potential implications as we move toward a future network architecture; and Alan Shribar suggested that competition and regulation can coexist. In addition, at a recent NARUC meeting, FCC chairman Fowler praised the success of deregulation and hoped for more; Commissioner Vial of the CPUC pleaded for local control of public policy; others praised the merits of legislation in the public policy area; and still others question "where's the beef" in deregulation.

I cite these various views and directions because they help provide an impression of the kaleidoscopic public policy world in which we live. There is no shortage of analyses, views, positions, forces, and tensions coming from an unprecedented array of learned men and women. Considering the breadth of views before
Companies) are required to file an ONA plan by February 1988. In the FCC's view, the plans to be submitted will describe the overall design of a carrier's basic network facilities and services to permit all users of the basic network, including the enhanced service operations of the carrier and its competitors, to interconnect to basic network functions and interface on an unbundled and equivalent basis. In addition, the FCC proposes that "basic service elements" (BSEs) must be available within one year after ONA plans are approved.

No one knows for sure what ONA or BSEs really are. Some issue areas have been described, and forums are under way or planned to develop better understanding. Some areas under discussion are: equal access (equal to BOCs' enhanced services), features and functions at interface, unbundling of basic services, resale capability, technical characteristics, installation, maintenance, and repair, availability, minimization of transport costs, and pricing standards. With so many unknowns around ONA and BSEs, I find it very interesting that some people have already chosen to tag descriptors onto ONA, such as "the future of competition" and "equal access for enhanced services." If these descriptors are relevant, it seems to me that we are required to look at the lessons learned in our "equal access" experience as we move forward in discussions of ONA. We need to apply these lessons as we learn to balance for the future.

History

As I look at the history of equal access, I see three major factors: ENFIA—Exchange Network for Interstate Access—Docket 200999; the Omnibus Docket—78-72 (and, later, the Access Order 82-579), and the MFJ. What have we learned from these three forces? What can we apply as we learn to balance for our future?

Basically, ENFIA enabled Other Common Carriers (OCCs) to interconnect to the integrated public switched network (PSN). It was a precursor to equal access and included discounted charges to the OCCs due to their perceived "less than equal" access. A key learning from ENFIA is that the OCCs were always considered to be interconnected customers (and potential competitors) of the PSN, with virtually no shared responsibilities or business partnerships with the PSN; while the Bell System and independent telephone companies worked together as integrated partners in the
PSN, with many joint responsibilities, close business relationships and noncompetitive franchises. In telecommunications, integrated entities assume understood boundaries (franchises), levels of partnership (cost sharing, joint responsibilities), and certain technical connection/operational arrangements, whereas interconnected entities may be competitors, have little or no joint responsibilities, and may receive (and pay for) "less than equal" access (hence the ENFIA discount).

FCC docket 78-72 helped bring access charges to life in docket 82-579. Economic criteria were used to move cost recovery from the long distance carrier to the supposed "real" cost bearer, the end-user. Of course, this "economically correct" charge created a direct charge to consumers everywhere, and a typical consumer reaction was felt. A key learning from this experience is that as you attempt to change public policy, be sure you maintain a broad perspective while considering all major stakeholders and their issues, not just the so-called experts. Indeed, while access charges' conception and gestation were overseen by clustered economists and regulators in Washington, their first "cry" in real life came about as consumers and congressional representatives quickly slapped the newborn before it exited the delivery room. The $6.00 access charge was halted pending further study, finally culminating in an initial $1.00 charge. I am not suggesting here that access charges are bad, but I am saying that we are remiss if we do not learn from the stakeholder interaction lesson taught in that experience.

The MFJ came not from regulators but from our judicial system. In the MFJ, equal access (access equal to that which the local BOCs provided to AT&T) was mandated, and the greatest technical conversion and attempted market conversion ever seen was initiated per a court approved schedule which preempted all other public policy agendas (state, PUC, FCC). Amazingly, the technical schedule was met. For example, Pacific Bell converted 8.3 million lines in 24 months, at a cost of about $210 million. The attempted market conversion to a multitude of alternative long distance carriers is another story. (It is interesting to note that there are fewer alternative carriers now than existed prior to the MFJ.)

It seems that a few lessons emerge from our MFJ experience. The first is that dramatic change may occur at any time, from any quarter (from regulators, markets, and courts). The second is that we, as an industry, and our employees always seem to solve the seemingly insurmountable technical and operational problems, at whatever sacrifice. The third, and perhaps most important, is that market conversion, through a public policy "mandate," is very difficult to achieve, may produce unforeseen results, and may prove to be very costly.

To underscore this last point, observe what Louise McCarron (Vermont PSC chairperson) and Kenneth Robinson (Policy Advisor, National Telecommunications and Information Administration) said in a recent forum (I am paraphrasing here): "Depending on your estimate, between $3 billion and $18 billion was spent to provide equal access supply, yet end-users produced a paltry demand—few came to the party (even though balloting and forced choice was applied). Supply and true customer demand were not balanced."

What does all this mean? What are the implications? What have we learned from our recent past that can be applied as we approach ONA?

**Summary of Key Lessons**

To summarize, as we look at our environment, we see global concerns regarding the balancing of supply and demand; as we look at telecommunications policy, we see the need to balance various policy factors and interests. Specifically, our equal access history contains several key lessons. (1) the balance between business relationships and types of interconnection/integration; (2) the need to work with various stakeholders and customers, not simply federally sanctioned "experts"; (3) the realization that forces of change in our industry come from all sides but that we typically do a great job of tackling the technical conversion problems associated with those changes; (4) the revelation that market conversion is very difficult to achieve and may produce unintended results with limited customer "benefit"; and (5) the understanding that we always need to consider the appropriate balance between the cost of supply and the consumption produced from true end-user customer demand.

**Toward ONA**

As we approach ONA we see several scenarios. First, potentially, significant change may occur as the nature of integra-
tion/interconnection and business relationships is affected again (unbundling, who can buy). Second, broad public policy issues and stakeholders are affected, such as subsidy, jurisdiction, pricing/costs, virtually all customers, state regulators, legislators, and so forth. Third, potentially great operational and technical effects may occur. Fourth, an attempt to mandate market conversion and structure may take place. Fifth, there may be a high cost to produce ONA "supply," with no clear picture of true end-user demand.

Considering all of this potential, and what we have learned in the recent equal access experience, what is our path forward? I would like to see a path that allowed some services, like voice mail, to be tested as integrated network services to a representative sample of customers as soon as they are technically available. Let us see where the supply/demand relationship is now and is likely to be. As we perform these tests, we can work the various issues with all stakeholders.

Conclusion

With customers' benefit firmly in our minds, I would advocate the following approach. Allow technology tests and market trials. Ask the tough questions now, not after an ONA mandate. Stimulate participation of key stakeholders in regional and national discussions. Probe questions around these kind of issues: Who benefits, who loses, considering levels of unbundling, who can purchase, subsidies for basic service, jurisdiction, and pricing/costs. Retain the local regulator role; is this really an issue which can be resolved solely on a national basis? Can it better be developed on a state basis considering economic conditions, degree of technology, demand, franchise responsibility, subsidies, competition, and so forth. Finally, balancing all of these will best balance the supply/demand equation and the broader public policy questions.

Remember, as a recent headline warns: "Economic Disaster Feared from Global Glut of Goods." We do not want to be forced (in ONA) into an unbalanced situation that creates disaster for our industry, the telecommunications infrastructure, and most important, for the full range of customers we serve. It is on all of us to learn from our past, consider all stakeholders, and best "learn to balance" for the future—a future for all customers which is sustainable and well balanced.
Part Three

Equal Access and Beyond – II
The NTS Bugaboo: A Survey of NTS Cost Recovery Programs for Intrastate Access

Robert W. Nichols

No one has yet resolved the bugaboo of telephone pricing: how nontraffic-sensitive (NTS) costs of the local exchange network should be recovered. This issue has remained a continuing source of concern, even annoyance, for federal and state policy makers for decades. Its significance lies in the fact that a major portion of the costs of the public switched network are generally labeled NTS, that is, they do not vary with usage of the network.

This failure to find an acceptable NTS cost recovery system has not come from a lack of trying. The FCC, Congress, the courts, state legislatures, public utility commissions (PUCs), the Joint Board, telephone companies, and consumer and other interest groups have all been active players in the policy game. No...

Note: This paper would not have been possible without the generous help cheerfully given by Tim Gates, Rebecca J. Bennett, Christy Miller, and Roxane Norenberg.
winning formula has yet been devised, in part because of the complex interrelationships among the economic, political, legal, and technical ground rules.

For example, in our federal system of shared regulatory jurisdiction over the telephone industry, the question of how NTS costs should be allocated between state and federal jurisdictions has historically been linked to the question of how NTS costs should ultimately be collected from end-users. Interstate NTS costs have traditionally been included in usage-sensitive toll rates; at the state level, they have been recovered through flat-rate local exchange charges as well as usage-sensitive toll charges. More recently, both types of jurisdictions have been experimenting with flat and usage-sensitive recovery tools.

The evaluation of various recovery mechanisms is also affected by conflicts over how NTS costs should be defined and measured. Recently, nationwide subscriber line costs (the largest portion of NTS costs) have been increasing at about $2.2 billion (or 10 percent) a year. This continuing growth in the size of the total NTS pool has led some commentators to warn that the effectiveness of existing recovery mechanisms is eroding and to call for close study of NTS cost data filed by local exchange companies.

Also complicating the NTS cost recovery picture are difficult questions about pooling or deaveraging of NTS costs, funds to subsidize high cost companies, lifetime and installation fee plans to aid the needy, phase-in implementation schedules, and the workability of often Byzantine tariff procedures.

Recognizing the existence of this complex web of concerns, this paper focuses more narrowly on the question of rate design: How should NTS costs of the local exchange network be recovered? Rather than review policy options suggested by academics, the focus is on how state PUCs are answering that question. After all, state telephone regulators usually cannot afford the luxury of waiting for a nationwide policy consensus; they regularly must review tariff proposals and determine what prices will be charged for telephone service in their state. It is access charge tariff proceedings which provide the forum for much of the policy debate on NTS cost recovery plans. Therefore, this paper primarily addresses orders of state PUCs concerning those tariffs. Attention is given to federal decisions and policies only to the extent that they appear to be affecting state decision makers.

The Survey

Recent PUC orders relating to access charges in all jurisdictions (50 states plus the District of Columbia) were analyzed in this survey. This document review was often supplemented with telephone conversations with PUC staff and parties to PUC proceedings. It was from these discussions that information about pending dockets and study committee deliberations was obtained.

The data generally reflect the situation in the various states as of December 1986. In certain instances, particularly involving proceedings then pending, the survey has been updated to reflect events occurring through January 1987.

Answers to two general kinds of questions were sought. First, what kind of charge (if any) is used to recover NTS costs directly from end-users. Second, what kind of charge (if any) is applied to interexchange carriers (IXCs) for NTS cost recovery. Related questions were asked regarding whether the relevant rates had changed since their first adoption and whether consideration was being given to changing the rate structure currently in place.

Results are summarized by state in tabular form in Appendix A and in narrative form in Appendix B. The table in Appendix A presents survey results in the form of "yes" or "no" answers to the following questions. (1) Is there a usage-based carrier common line charge (CCLC) imposed on IXCs? (2) Has there been a reduction in the CCLC since its adoption? (3) Is there a subscriber line charge (SLC), that is, a flat-rate end-user fee (also known as a CALC)? (4) Is there a flat-rate IXC charge allocated by relative network capacity? (5) Is there a flat-rate IXC charge allocated by relative market share measured by minutes of use (MOU)? (6) Is there a direct end-user charge billed on a usage-sensitive basis, pursuant to a volume discount ("taper")? These results are summarized and highlighted under a number of topics in the discussion which follows.

Survey Results

Traditional or Alternative Model NTS Plans

The survey revealed there are two general models of NTS cost recovery plans. The first, here called the "traditional model," has the central characteristic of using only a CCLC to recover NTS
costs from IXC's. Other features may or may not be present, including a subscriber line charge to recover costs directly from end-users and a reduction in the CCLC rate since its adoption.

States which use something other than the CCLC to recover NTS costs from IXC's are grouped under the general heading of "alternative models." Included here are flat-rate charges which apportion a fixed NTS revenue requirement among carriers by either a measure of capacity or by minutes of use. The Universal Local Access Service (ULAS) plan is the primary example of this variety of flat-rate plan.

Another alternative model variant is the direct end-user charge billed on a tapered usage-sensitive basis. The plan sponsored by NYNEX, which the FCC rejected on November 25, 1986, is an example. This direct end-user plan differs from other alternative models in several respects, including that it proposes billing both traffic sensitive (TS) and NTS costs for originating access directly to the end-user.

It is important to note that plans which include both a CCLC and an alternative NTS mechanism are included among the alternative models. Each state's NTS recovery plan is placed in one of these two general models in Appendix A and described in more detail in Appendix B.

Specific Findings

The survey results reveal several particular characteristics of state NTS cost recovery plans.

A Large Majority of States Follow the Traditional Model

Seven jurisdictions (Arkansas, Connecticut, Delaware, District of Columbia, Hawaii, New Hampshire, and Rhode Island) of the fifty-one (or 14 percent) do not presently have intrastate access charges, presumably because they are single LATA jurisdictions which do not allow competition. When these jurisdictions are left out, forty-four states have intrastate NTS cost recovery plans in the form of access charges.

As Table 1 shows, a 77 percent majority of the states with NTS plans fall into the traditional model, that is, they use the CCLC exclusively to recover NTS costs from IXC's. Within this model there is some variation on whether steps have been taken to reduce the loading of NTS access costs onto toll rates. A decision to collect more NTS costs directly from the end-user can be reflected in two

<table>
<thead>
<tr>
<th>Model</th>
<th>No. of States</th>
<th>Percent of States</th>
</tr>
</thead>
<tbody>
<tr>
<td>Traditional</td>
<td>34</td>
<td>77%</td>
</tr>
<tr>
<td>Alternative</td>
<td>10</td>
<td>23%</td>
</tr>
</tbody>
</table>

*Percentage of 44 states with tariffed access charges.

Table 2: Traditional Model Plans, 44 States

<table>
<thead>
<tr>
<th>Element</th>
<th>No. of States</th>
<th>Percent of States</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCLC</td>
<td>34</td>
<td>100%</td>
</tr>
<tr>
<td>CCLC Reduction</td>
<td>22</td>
<td>65%</td>
</tr>
<tr>
<td>Subscriber Line Charge</td>
<td>5</td>
<td>15%</td>
</tr>
<tr>
<td>CCLC Reduction and SLC</td>
<td>4</td>
<td>13%</td>
</tr>
</tbody>
</table>

*Percentage of states with Traditional Model Plans.

ways in this survey. First, states may have lowered the CCLC charge on IXC's. Second, they may have adopted a subscriber line charge to pass on these costs via a flat end-user fee.

Table 2 shows the degree to which states have taken action to reduce NTS loading on toll. A significant majority (65 percent) of traditional model states have followed the FCC lead and reduced CCLC rates since their adoption. Just where these NTS costs have been shifted is not readily apparent. Only five states (Alabama, Illinois, Indiana, Mississippi, and New Mexico) have adopted a state SLC to pass on the costs to end-users directly. Because this survey covered only access related orders, it is not possible to say for sure how many states have acted to raise local exchange rates without labeling the increase a subscriber line charge. However, as discussed later, this survey did in fact identify some states in which this type of increase has occurred.

Alternative Plans Have Been Adopted in Ten States and All Are Flat Rate. Ten states have adopted an alternative NTS plan. This means they are using something other than the CCLC to recover NTS costs from IXC's, although they may use a combination of
CCLC and an alternative NTS recovery mechanism. This represents about 23 percent of all states with access tariffs.

As Table 3 shows, all of these currently adopted alternative plans involve the use of a flat-rate charge on IXC. These plans usually have a fixed NTS revenue requirement associated with access services which is not affected by changes in access demand or other business risks. The IXC then pay their NTS charges via a lump-sum (flat-rate) payment determined by their relative market share measured either by network capacity or minutes of use. By contrast, under the CCLC, IXC pays a charge per minute which is the same for all carriers. There are no states in which a tapered end-user plan has been adopted.

Significantly, the great majority of states which have adopted alternative plans hedge their bets: They retain the CCLC and use the flat-rate element as a supplemental feature. In fact, as illustrated in Table 4, only three states have alternative plans which completely replace the CCLC (labeled “Pure plans” in the table). The remaining seven states have hybrid schemes in which the CCLC is used to recover some NTS costs and the alternative plan another portion, usually a residual. One can infer from this that most states still view alternative plans as experimental in nature without a sufficient track record to warrant use as a complete replacement of the traditional CCLC mechanism.

Many States Are Studying Alternative NTS Plans. Despite the fact that only ten states have adopted an alternative NTS plan, many more state PUCs are clearly interested in the topic. As listed in Table 5, twenty-four state commissions are presently studying such plans (or recently have done so). Some already have adopted one (such as Kentucky and Florida), are evaluating their experience, and are considering changes or modifications. Most, however, currently have traditional plans and are contemplating adoption of an alternative plan. This is most often the case in pending or recently concluded access proceedings. Other states (Florida, Maryland, and Montana) have indicated that they expect to hold future proceedings to consider alternative NTS cost recovery plans or evaluate the one they have adopted.

Finally, in five states the PUCs have appointed an industry and staff task force to study alternative plans. As of January 1987, three of these had issued reports, and all recommended continued use of the CCLC mechanism rather than any of the alternative NTS plans. As a result of the North Dakota report, the state commission entered an order reversing an earlier endorsement of a flat-rate plan and required the continued use of the CCLC mechanism. Task force reports were submitted in Arizona and Minnesota in December 1986 and January 1987, respectively, recommending use of the CCLC over alternatives. The Minnesota report is particularly thorough in analyzing the relative merits of various plans according to a number of criteria. Neither the Arizona nor Minnesota commissions has yet taken official action on the reports' recommendations. Study groups are still working in Kansas and Wisconsin.

Recent Events Favor the Traditional Model. Various reasons have been suggested by parties to PUC proceedings for the adoption or rejection of alternative NTS plans. While it is outside the scope of this paper to discuss these arguments in detail, it may be useful...
Table 6. The 24 States Considering Alternative NTS Plans

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<tr>
<th>State</th>
<th>Description</th>
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<tr>
<td>Arizona</td>
<td>An industry committee studied alternative NTS cost recovery plans and recommended retention of the CCLC in a report dated December 2, 1986.</td>
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<td>California</td>
<td>In a pending access charge proceeding, PacBell has proposed a flat-rate MOU plan.</td>
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<tr>
<td>Colorado</td>
<td>A pending proceeding includes a proposal for a ULAS plan and one based on the FCC’s WATS Access Charge Order.</td>
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<td>Florida</td>
<td>The PUC has announced that future hearings will examine alternative NTS cost recovery plans, including ULAS and end-user taper plans.</td>
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<td>Illinois</td>
<td>The PUC has ordered a task force to continue work on an experimental unified tariff submitted to the FCC.</td>
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<td>Kansas</td>
<td>The PUC has ordered a study of alternative NTS cost recovery plans to be submitted by August 1, 1987.</td>
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<td>ULAS has been adopted but the PUC is examining alternative allocation plans (MOUs, BMOOs, and so forth.)</td>
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<td>Maine</td>
<td>A pending docket is considering a proposal to replace the CCLC with an end-user taper plan.</td>
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<td>Maryland</td>
<td>The PUC has indicated that it expects future dockets to examine alternative NTS cost recovery plans which may replace the current flat-rate MOU plan.</td>
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<tr>
<td>Massachusetts</td>
<td>An end-user taper plan is under consideration in a pending proceeding.</td>
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<td>Minnesota</td>
<td>A PUC appointed committee issued a report on alternative NTS cost recovery plans which favored the CCLC on January 30, 1987.</td>
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<tr>
<td>Montana</td>
<td>The PUC has noted the debate on alternative NTS cost recovery plans and indicated they may be the subject of future hearings.</td>
</tr>
<tr>
<td>Nebraska</td>
<td>A flat-rate MOU plan was recently considered but rejected in an access order issued in December 1986.</td>
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(Continued)
CC Docket No. 86-1 regarding WATS access lines ("WATS Access Charge Order"). Among other items, this order reinstated the special access treatment of the closed end of WATS and thereby replaced the CCLC with a flat charge on the closed end. In addition, the commission shifted some NTS costs from the originating to the terminating end of the CCLC for all switched access services.

State PUCs are just beginning to digest the significance of the FCC’s order. Judging from the early reactions, however, it appears that this order will reduce, perhaps significantly, the interest in alternative NTS cost recovery plans. This is because this order is expected to lessen any existing pressures for bypass of the switched network, which is the paramount concern addressed by the alternative NTS cost recovery plans. Also yet to be considered are suggestions by the Joint Board in early 1987 that lifeline plans be improved and a new mechanism to offset high installation costs be considered. Such plans clearly go to another of the reasons advanced for alternative NTS cost recovery plans, that is, that they help preserve universal service.

Evidence of the early reaction to the FCC’s WATS Access Charge Order can be found in the task force recommendations in Minnesota and Arizona mentioned previously and the recent in Washington State. Each of these suggests or permits altering the intrastate CCLC by reducing the proportion of NTS costs to be recovered on the originating end (the end where bypass is more likely to occur).

The SLC Is Not Very Popular with PUCs, Only Six States Having Adopted One. An intrastate, flat-rate subscriber line charge has been adopted by only six states (Alabama, Illinois, Indiana, Michigan, Mississippi, and New Mexico). All but Michigan are traditional model states using a CCLC to recover NTS costs from IXCs. While emphatically rejecting a subscriber line charge in 1984, Michigan recently adopted one. It is used, along with a flat-rate charge on IXCs, to recover any local exchange carrier revenue shortfall (from 1984 levels) caused by a declining CCLC.

Even though few states have actually adopted a subscriber line charge, it is clear (as mentioned previously) that others have shifted NTS costs to end-users in the form of higher local rates without separately identifying the increase as a “subscriber line charge.” Determining how many states have done this is difficult because it requires analysis of more than just access charge orders.

A reading of state PUC orders obtained for this survey, however, reveals that such action has been taken by several states (for example, Arkansas, California, Florida, Montana, North Dakota and Oregon). (See Appendix B.)

Conclusion

A large majority of NTS cost recovery plans for intrastate access follow a traditional model, that is, they utilize the usage-based CCLC exclusively for recovery of NTS costs from IXCs. Most of these states have reduced the CCLC over time, thus reducing the NTS cost burden on toll. Exactly where this cost burden has been shifted is less clear. Few states have adopted a flat-rate SLC, but many have apparently raised local rates without attaching a label of “subscriber line charge” to the customer’s bill.

Only ten states have adopted an alternative model NTS cost recovery plan to date. All incorporate flat-rate charges to IXCs. These flat charges are usually apportioned among carriers on the basis of relative MOUs, but a few use relative network capacity.

More importantly, these alternative plans are in fact hybrid schemes which continue use of the CCLC while supplementing it with a flat-rate tariff element.

Significantly, twenty-four states are now studying one of the alternative NTS plans (or recently have done so). This reflects real interest in refining existing mechanisms to conquer the NTS cost bugaboo. The latest development, however, is that PUCs are just beginning to digest the FCC’s WATS Access Charge Order. This order seeks to prevent bypass incentives by removing the CCLC from the closed end of WATS and reducing the originating CCLC charge for all switched access products below that for terminating minutes. Also yet to be analyzed are even more recent proposals by the federal-state Joint Board to enhance lifeline programs and create a plan to offset high installation costs.

Given the importance of concerns about bypass and preservation of universal service to the impetus for alternative NTS cost recovery plans, it can be expected that these federal developments may affect PUC thinking in the future. Early indications are that these modifications may substantially reduce the interest of PUCs in alternative NTS cost recovery plans.
Notes
4. A fuller treatment of the claimed advantages of alternative flat-rate NTS cost recovery plans can be found in the testimony of Dr. Bea Johnson in a number of state PUC proceedings. For example, Direct and Surrefractal Testimony of Dr. Bea Johnson, Docket No. 1720, Colorado Public Utilities Commission, a proceeding still pending as of January 1987.
6. WATS-Related and Other Amendments of Part 69, 59 R.R.2d 1418 (1986); (Report and Order in CC Docket No. 86-1, released March 21, 1986).

Robert W. Nichols

Appendix A. State NTS Recovery Plans

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Traditional Model

Alternative Model

Flat Rate
A Survey of NTS Cost Recovery Programs

(Appendix A continued)

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SLC—Subscriber Line Charge: flat-rate end-user charge for NTS cost recovery.

CCLC—Carrier Common Line Charge: usage-based IXC charge for NTS cost recovery.

CCLC Reduct.—Has the CCLC been reduced since adoption.

Flat Rate (Capacity)—Flat-rate IXC charge for NTS cost recovery allocated by relative network capacity.

Flat Rate (MOU)—Flat-rate IXC charge for NTS cost recovery allocated by relative minutes of use (MOU).

Taper—End-user charge tapered by volume for NTS cost recovery.

Other—Alternative plans not in other categories.

*No intrastate access tariff.

**Although it is classified as having a traditional model plan, Arizona couples the CCLC with a fixed NTS revenue requirement which has many characteristics of a flat-rate plan.

***The capacity based charge is the same for all carriers per busy-hour minute and is therefore different in this respect than other flat-rate plans.

Appendix B. State-by-State Summaries

Alabama—SLC is in place and varies by local exchange company (LEC) from $0 to $0.85 per month. CCLC mechanism is in place via Docket No. 19556 (effective 8/1/85). CCLC also varies by LEC. There have been two reductions in CCLC rates since they were initially implemented. No apparent consideration of alternative NTS plans to date.

Alaska—This is a single LATA state which does not presently permit competition. There is no current intrastate access charge tariff. A long-standing docket considering competition and access charges is about to be closed and another begun (Dkt. No. 83-63).

Arizona—No SLC is in place. A CCLC is currently in place, and CCLC rates have been reduced since its adoption. The first state access tariff was a simple bulk bill system applicable only to AT&T prior to authorized competition. A second interim tariff was approved in January 1985 and was modeled after the FCC tariff, that is, it included a CCLC. In May 1985, Mountain Bell proposed a new permanent tariff including a flat-rate ULAS plan to collect NTS costs from interexchange carriers (IXCs). This was rejected by the Corporation Commission, which retained the CCLC (Decision No. 54843, Dkt. No. E-1051-84-100, issued January 10, 1986). However, because the NTS revenue requirement is fixed, the access charge has many of the characteristics of a flat-rate plan. This decision ordered Mountain Bell, and other interested parties, to study alternative NTS recovery plans and submit a report. This report was filed on December 2, 1986, and recommended retention of the CCLC mechanism as revised by the FCC's WATS Access Charge Order. A pending docket will consider intrastate competition and access charges (Dkt. No. U-0000-84-058).

Arkansas—No SLC has been adopted. However, the PUC has approved a reduction in intrastate NTS costs on toll from an SPF-based level to SLU over seven years and permitted local rates to be increased as a result (Order Nos. 37 and 40, Dkt. No. 83-42-U, issued December 19 and 31, 1985, respectively). With regard to rate design, the original interim access tariff was modeled after the FCC access structure and contained a CCLC (at about 6.86 cents/minute) (Order No. 7, Dkt. No. 83-042-U, issued December 7, 1983). Subsequently, the commission replaced the CCLC with a flat-rate charge allocated to IXCs on the basis of billed conversation minutes (including both switched and special access) (Order No. 37, Dkt. No. 83-042-U, issued December 12, 1985). Arkansas authorized interLATA competition on December 12, 1985 (Order No. 36, supra.)

California—No SLC has been adopted. The commission has
adopted a plan to reduce NTS costs loaded on intrastate toll from an SPB-based level to SLU by 1992 (Decision No. 85/06/115, Appl. No. 83-01-22 Phase 2B). A CCLC has always been used to recover NTS access costs from IXCs. A pending docket is considering access issues, including a proposal by Pacific Bell to implement a flat-rate NTS charge allocated to carriers based on their proportionate share of total switched MOUs (Supra, Phase 3C). This is basically the same plan Pacific Bell submitted to the FCC, which rejected it (In the Matter of Petitions for Waiver of Various Sections of Part 69, Memorandum Opinion and Order, released April 28, 1986).

**Colorado**—No SLC has been adopted. The current access charge tariff uses a CCLC to recover NTS costs from IXCs. This Mountain Bell tariff (Advice No. 1957) was issued on June 29, 1984, and took effect under operation of law on July 29, 1984. No hearing was held and no decision was issued by the commission. There is a current docket pending in which access charge issues are being considered (Dkt. No. 1720). Mountain Bell has proposed a new access charge tariff which would retain the CCLC essentially in the form presently approved by the FCC (including a lower CCLC on the originating end than for terminating MOUs). The Office of Consumer Counsel proposed the flat-rate ULAS tariff either in its capacity form or MOU variety.

**Connecticut**—This is a single LATA state which has a statutory moratorium on competition until July 1987. Currently, there is no intrastate access charge tariff.

**Delaware**—This is a single LATA state which has not authorized competition and has no intrastate access tariff. A docket regarding authorizing intrastate competition is pending (Dkt. No. 10).

**District of Columbia**—There is only one LATA in the district and no toll traffic that is not interstate. Thus, there is no intrastate access tariff.

**Florida**—There is no intrastate SLC. There are currently two types of charges to recover intrastate NTS costs: a CCLC and a Busy Hour Minutes of Capacity (BHMMC) charge. The CCLC was originally set to mirror the FCC charge and the BHMMC to recover the residual NTS costs (Order No. 1265, December 9, 1983, and Order No. 12765-A, December 22, 1983). The BHMMC charge is the same for all carriers per unit of BHMMC; the charge to each carrier is not determined by an allocation process and is, in that important respect, unlike the other flat-rate charges discussed in this paper. A “leaky PBX” fee is levied on end-users who fail to certify that local calls are not being made over private lines. The commission filed a proposed unified, state, and interstate access tariff plan which the FCC rejected. In late 1985 the commission tentatively endorsed the flat-rate ULAS concept to replace its BHMMC charge (Order No. (K) 15481, Dkt. No. 820537-TP, December 23, 1985). On reconsideration, it withdrew this tentative endorsement and ordered additional proceedings to evaluate a variety of alternative NTS cost recovery plans (Order No. 15963, Dkt. No. 820537-TP, April 7, 1988; the new docket in which these plans are to be considered is No. 860984). The state has a “free & keep” scheme for access charges; there is no pooling. Although repeatedly rejecting a flat SLC, the commission has several times indicated its desire to adopt a usage-sensitive charge for originating access billed directly to the end-user (presumably some kind of tapered charge). The commission’s stated goal is to adopt such a charge for each EAEA (22 commission-created Equal Access Exchange Areas) as each is converted to equal access (Order No. 15481, supra). No such usage-based end-user fee has been adopted to date.

**Georgia**—No SLC has been adopted. The commission adopted an interim access tariff on December 7, 1983, which essentially mirrored the FCC plan (CCLC) but did not include an SLC. Subsequently, the commission considered the flat-rate ULAS proposal but rejected it (Initial Decision, Dkt. No. 3430-U, issued September 16, 1985; became final order).

**Hawaii**—This is a single LATA state where no competition is allowed currently. There is no present intrastate access tariff.

**Idaho**—There is no intrastate SLC; it has been repeatedly rejected by the PUC (Order No. 18525, Case No. U-1500-148, issued December 9, 1983; Order Nos. 20182 & 20277, Case No. U-1500-153, issued December 31, 1985 and February 18, 1986, respectively). Moreover, the commission has adopted a gross allocator of 25 percent of NTS costs to intrastate toll (25 percent interstate & 50 percent local) which increased the NTS allocation on intrastate toll for three of the four largest LECs. The CCLC is in place on an intra-LATA basis, although presently there is no intralATA competition. The commission adopted the flat-rate ULAS tariff
to collect NTS costs from interLATA access. Presently, AT&T is the only interLATA authorized facilities-based carrier and thus the only carrier subject to the ULAS tariff. A pending docket (Dkt. No. U-1500-162) is expected to affect access charges.

**Illinois**—The Commerce Commission has adopted an SLC, currently at $5.52, with a $0.64 increase due in January and July 1987. A CCLC is in place for IXC's on an inter-MSA (“market service area” local name for LATAs) basis. The commission adopted a plan in 1985 (“Alternate Plan”) to reduce NTS cost recovery from IXC's and reduce inter-LEC pooling. As a result, the CCLC has been reduced several times since it was first adopted (4th Interim Order, Dkt. No. 83-0142, November 23, 1983). A proposed experimental unified state-federal access tariff has been filed with the FCC.

**Indiana**—There is an intrastate SLC (Final Order, Cause No. 37200, June 27, 1985; Interim Order, Cause No. 37905, January 8, 1986). IXC's are assessed a CCLC under a tariff that, in structure, basically reflects the FCC plan. No alternative NTS tariff is under active consideration.

**Iowa**—There is no SLC. The Commerce Commission (now the Utilities Board) adopted emergency access rules on September 25, 1983, which mirrored the FCC structure and included an SLC. The SLC was deleted November 4, 1983, before these interim rules went into effect on December 1, 1983. Current access tariffs are governed by rules adopted in February 1984 (Order Adopting Rules, Dkt. No. RMU-83-33, issued February 24, 1984; rules are located at IAC 250 22.14(476) & 22.15(476)). These rules provide for a CCLC which has remained constant at $0.06 per minute for each end. They also impose a fee on certain bypass facilities. There is no pending docket considering alternative access charge plans.

**Kansas**—There is no SLC. The Corporation Commission recently issued an order establishing the basic structure of inter-LATA access tariffs to be effective in 1987 (Order, Dkt. Nos. 127,140-U (Phase IV), 86-SWBT-50-TAR, 86-KILT-86, issued October 10, 1986). This order included a $1.00 shift of NTS costs from access and toll to local and vertical services. The original proposals of both Southwestern Bell and KILT (an association of independent companies) for inter-LATA access included flat-rate NTS charges to IXC's (submitted February 13, 1986). Parties to the proceeding later signed a settlement which proposed continuation of the usage-based CCLC. The commission approved this industry settlement in its October 10, 1986, order. In that order the commission required that an industry report on flat-rate NTS charges to IXC's be submitted to the commission by August 1, 1987.

**Kentucky**—There is no SLC. After giving initial approval to a CCLC-based system (December 29, 1983; January 19, 1984), the commission adopted a combination of CCLC and flat-rate ULAS elements (Order, Case No. 8838, November 20, 1984; Order on Rehearing, February 15, 1985). The intrastate CCLC is set at approximate parity with the FCC level; as this declines, any residual NTS revenue requirement is recovered via the flat-rate ULAS charge. The commission has issued a number of orders concerning implementation of ULAS in Case No. 8838 (that is, orders dated May 1, 20, and 31, 1985). The commission is currently considering different methods of allocating revenue responsibility among IXC's, such as BHMO and IXC billed MOU in this same docket.

**Louisiana**—There is no current SLC. There is a CCLC (Order No. U-15985, Dkt. No. U-15985, January 1, 1984). The CCLC rate has been reduced, although the entire access charge structure has not been fully addressed in an order. A pending proceeding does involve consideration of an intrastate SLC.

**Maine**—No SLC. There is a CCLC mechanism. A current docket will consider the NYNEX end-user taper proposal (Dkt. No. 86-7).

**Maryland**—There is no SLC. The commission originally adopted a flat-rate IXC charge allocated by the relative number of unsubscribed equal access lines (Order No. 67035, Case Nos. 7851 & 7816, May 29, 1986; amended by Order No. 67042, May 31, 1985). In January 1986, AT&T petitioned the commission to change this allocation mechanism to one based on an IXC's relative number of switched access minutes. The commission adopted this revision (Order 67365, Case No. 7936, April 25, 1986). It declined to adopt a staff proposal to allocate on the basis of relative IXC intrastate revenue. The commission indicated that none of the NTS recovery plans was perfect and noted that the issue would likely be revisited.

**Massachusetts**—No SLC. The CCLC mechanism is in place, and there have been no reductions in the level of this charge. In a pending docket concerning costing mechanisms, an illustrative
tapered end-user access plan was filed and is likely to receive some attention, although it was not formally proposed (Dkt. No. 86-33 and 86-134).

**Michigan**—In 1984-1985, Michigan decided to mirror the FCC access charge structure (including a CCLC) on an interim basis except for the SLC, which it specifically rejected (Opinion & Order, Case No. U-7473, July 3, 1984, and June 26, 1985). Under this system, as the intrastate CCLC was reduced (because of mirroring the FCC rate), any revenue deficiency was recovered via a “Michigan Transition Mechanism” (MTM), which is a flat rate IXC charge allocated on relative minutes of use. On May 28, 1986, the commission modified this system by adding an intrastate SLC ($0.22 to $0.37). Currently, any revenue deficiency as a result of mirroring interstate rates is recovered from both the MTM and SLC (Opinion & Order, Dkt. Nos. U-8082, U-8084, and U-8085, May 28, 1986). In this last order, the commission rejected the ULAS proposal.

**Mississippi**—There is no SLC. A CCLC is currently in effect to recover the residual NTS revenue requirement of NW Bell. It has not been reduced. In early 1986, the PUC rejected a ULAS plan but proposed to replace the CCLC with a flat-rate IXC charge based on relative MOUs (Order, Dkt. Nos. P-421/CL-85-555, et al., February 2, 1986). On reconsideration, the Commission retained the CCLC and ordered a report on alternative NTS recovery plans from a staff and industry committee. This report was issued on January 30, 1987, and recommends retention of the CCLC as recently modified by the FCC’s WATS Access Charge Order (that is, reducing the originating end CCLC and retaining current levels at the terminating end). This recommendation is being considered in a pending access charge proceeding (CL-85-559).

**Missouri**—There is a recently adopted SLC. There is a CCLC which has been reduced over time (Order, Dkt. No. U-4839, September 9, 1986). No alternative NTS recovery mechanism is in place or is under active consideration.

**Montana**—There is no SLC, but the commission recently approved local rate increases as a result of moving in two steps to an SUU allocator for NTS on access charges (Order No. 5055g, Dkt. No. 84-4.15, May 23, 1985). In the past, the commission has gone from bulk billing of NTS access costs, to a CCLC, back to bulk billing, and then back to a CCLC. In the May 1986 order, the commission rejected adoption of a flat-rate MOU plan and approved general use of the CCLC mechanism. However, a stipulation between AT&T and one LEC (Northwestern Telephone Systems) was approved so the LEC could bill AT&T via a 20 percent CCLC and 80 percent flat-rate system, with the flat-rate amount allocated among IXCs according to their relative MOUs. Nonpremium access minutes are to be billed under the CCLC by this LEC. The commission also noted that other alternative NTS recovery plans were being debated nationally (such as one-plus, NYNEX taper, and ULAS) and may be the subject of future hearings.

**Nebraska**—There is no SLC. Otherwise, the commission has generally adopted the structure and rates of the interstate tariffs, including a CCLC (Opinion & Findings, Application No. C-465, December 27, 1983). CCLC rates have been reduced since first adopted. In a recent access charge proceeding the commission rejected a flat-rate NTS charge to IIXCs allocated on relative MOUs and decided to retain the CCLC in an order dated December 16, 1986 (Appl. No. C-627).

**Nebraska**—There is no SLC. There is a CCLC which has not been reduced. An access charge proceeding is pending in which proposals for reducing the CCLC and adopting alternative plans are expected to be considered (Dkt. No. 86-711). The commission has rejected the ULAS plan in the past but expressed interest in further study of that and other alternative plans.

**New Hampshire**—This is a single LATA state in which competition is not currently authorized. There is no intrastate access charge tariff.

**New Jersey**—No SLC. No CCLC. The access related NTS costs allocated to IIXCs are recovered via a flat-rate charge allocated among carriers according to their proportionate intrastate switched MOUs (Order, BPU Dkt. Nos. 8311-1035 and 8311-1064, January 3, 1986).
New Mexico—There is an SLC (Final Order II, Dkt. No. 1052, December 16, 1983). Although this is essentially a single LATA state, there is some limited interLATA traffic. A statute enacted in 1986 permits competition intrastate. The Corporation Commission recently gave interim approval to access charge tariffs, effective in January 1987, which contain the CCLC (Interim Order, Dkt. No. 1115, November 15, 1986). This order reaffirmed the commission’s intention that NTS charges in the future should be allocated between access and toll on a market-based approach. No docket is considering alternative plans at present.

New York—There is no intrastate SLC. The commission has, however, determined that NTS costs should be shifted from access and toll and has taken steps to raise local rates partially to offset such reductions (Opinion No. 85-17, November 11, 1985; Opinion No. 85-16, Case 28710, October 3, 1985). Additional increases have been recommended (Rec. Decision, Case 28425, October 30, 1986). The CCLC mechanism is in place, and CCLC rates have been reduced (Opinion No. 85-17, supra.). More reductions have been recommended (Rec. Decision, supra.). There remains a surcharge on intraLATA toll and interLATA access related to maintenance of a state pool at 1984 levels; reduction or elimination of this surcharge and of pooling is under consideration. There is no active consideration of alternative NTS cost recovery mechanisms currently.

North Carolina—There is no SLC. There is a CCLC mechanism, and CCLC rates have been reduced since their original adoption (Order, Dkt. No. P-100, SUB 65, September 15, 1985). There is a pending access proceeding in which a further reduction in the CCLC and the ULAS plan are under consideration (Dkt. Nos. P-100 SUB 65, SUB 72). A decision was expected in December 1986.

North Dakota—There is no SLC. The commission has, however, permitted local rate increases to offset reductions of the NTS loading on access and intraLATA toll (Order, Case Nos. 10,694 & 10,699, October 7, 1986). In this 1985 order, the commission adopted the concept of replacing the CCLC with a flat-rate charge. The commission ordered a staff-industry study committee to evaluate alternative flat-rate plans and report to the commission. On October 7, 1986, the commission reversed itself and ordered continuation of the CCLC mechanism (Suppl. Findings, Case Nos. 10,694 & 10,699, October 7, 1986). The commission relied on the report of the study committee, which after evaluation of a variety of flat-rate plans for use in a multicarrier environment found the CCLC mechanism to be superior.

Ohio—There is no SLC. There is a CCLC mechanism in place. CCLC rates have been reduced several times. Access rates, including the CCLC, have mirrored the FCC rates. Any revenue shortfall (from 1983 levels) in intrastate revenues has been compensated for through a pooling mechanism funded by a “carriers presence charge” (CPC) (Order, Case No. 83-464-TP-COI, May 21, 1984). In early 1986, the commission issued an order phasing out the pool and the CPC (Suppl. Order, Case No. 83-464-TP-COI, February 2, 1986). There is a pending access charge case in which one party is proposing a flat-rate plan.

Oklahoma—There is no SLC in effect. There is a CCLC which has been reduced since it was initiated (Order No. 285023, Cause No. 28309, September 10, 1986). There is a surcharge on the interLATA CCLC and on intraLATA toll and WATS MOUs. A proposal is being considered in a pending docket which would replace the CCLC with a flat-rate IXC charge allocated by relative MOUs and would increase local rates (Stipulation, Cause No. 28309, October 10, 1986).

Oregon—There is no separately identified SLC. However, local service price increases have been approved to offset reductions in IXC NTS charges and intralATA toll rates (Interim Orders, Dkt. Nos. UT-42 & UT-43, December 19, 1985). For calendar 1986, 25 percent of the IXC’s NTS costs were recovered via a CCLC, while 75 percent were recovered by a flat-rate IXC charge allocated by relative switched access MOUs. A pending settlement in a current access charge case reportedly will return to a 100 percent CCLC system for 1987 (Dkt. No. UT-45).

Pennsylvania—There is no SLC. There is a CCLC, which has been reduced since it was first adopted. An August 1985 order affirmed the basic access structure and rejected a proposal to phase out IXC NTS contributions in three years. No revision in access structure is under active consideration currently.

Rhode Island—Competition is not authorized in this single LATA state. There is no intrastate access tariff.

South Carolina—There is no SLC. A CCLC is in place, which has been reduced since it was adopted. Access rates generally mir-
ror those approved by the FCC (Order No. 86-584, Dkt. No. 82-134-C, June 9, 1986, and July 1, 1986). In its 1986 order, the commission adopted time-of-day discounts for access charges and rejected a proposal that IXCs be assessed a flat-rate NTS charge based on capacity or MOUs.

**South Dakota**—No SLC. The CCLC is in place, and there have been reductions since its adoption (Order, Dkt. No. F-3582-12, September 23, 1986). There is no active consideration of alternative NTS plans.

**Tennessee**—There is no SLC. There is a CCLC structure for recovering NTS costs from IXCs (Order, Dkt. No. U-83-7261, et al., March 4, 1985). The commission has reduced the CCLC and intraLATA toll rates (Order, Dkt. No. U-86-7443, August 27, 1986). There is no pending active consideration of alternative NTS cost recovery plans.

**Texas**—There is no SLC. There is a CCLC applied to IXCs, and it has been reduced since it was originally created (Order, Dkt. No. 6200, June 26, 1986). A surcharge on the CCLC (an "ICAC") is in place which funds a pool to provide revenue support to LECs (Dkt. No. 5113 Phase II). The commission has declined to adopt a ULAS proposal or a flat-rate IXC NTS charge allocated by market share or number of customers (Dkt. No. 6200, supra; Dkt. No. 5113). However, the commission ordered its general counsel to begin an investigation of alternative flat-rate NTS plans in its June 26, 1986, order and the counsel recently filed a petition for such an inquiry (Original Petition for Inquiry, filed November 17, 1986).

**Utah**—There is no SLC. Utah currently permits only reseller competition to LECs in this one-LATA state. There is an access charge with a CCLC structure. The commission established an investigation into state-specific NTS costs but has basically relied on interstate rates in the interim (Rept. & Order, Case No. 83-999-11, October 29, 1983). The commission has found that it has reduced the market-based competition is allowed, Mountain Bell would have to assess itself access charges at the same level as it charges other IXCs.

**Vermont**—There is no SLC. The Vermont Public Service Board has basically adopted the federal access charge structure and rates on an interim basis. There is a CCLC in place, which has been reduced since its adoption. In a currently pending access proceeding, New England Telephone is proposing an end-user ta-

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Virginia—There is no SLC. The State Corporation Commission adopted access charges which essentially mirror the FCC structure, including a CCLC (Interim Order, Dkt. No. PUC83020, December 23, 1983). There is no current docket evaluating alternative NTS cost recovery mechanisms.

**Washington**—There is no SLC. Although the Washington Utilities & Transportation Commission originally authorized an SLC up to $2.00 per line, this decision was reversed, and SLCs ended April 30, 1984. The CCLC is currently used to assess access related NTS charges to IXCs. The CCLC has been reduced over time. The Proposed Order in a recent access proceeding would have used a flat-rate IXC charge (allocated by relative MOUs) to recover 25 percent of IXC NTS charges; the remaining 75 percent would be recovered via a CCLC (17th Suppl. Order, Cause No. U-85-23 et al., September 22, 1986). The commission's Final Order rejected this modified flat-rate plan, returned to a CCLC structure and permitted a filing compatible with the FCC's WATS Access Charge Order. This order also required Pacific Northwest Bell to assess itself access charges identical with those it imposes on other IXCs (16th Suppl. Order, Cause No. U-85-23 et al., December 30, 1986, and 19th Suppl. Order, Cause No. U-85-23 et al., January 20, 1987).

West Virginia—There is no SLC. There is a CCLC, which has been reduced since its adoption. There is a pending access charge proceeding in which a flat-rate IXC charge allocated on relative switched MOU has been proposed (Case No. 86-304).

Wisconsin—There is no SLC. There is a CCLC in operation, which has been reduced since its adoption. The commission announced its intention to replace the CCLC with a flat-rate IXC charge based on relative network capacity (ULAS) (Order, Dkt. No. 85-TR-5, Part B, February 20, 1986). It ordered the creation of staff and industry task forces to work out necessary implementation matters. To date there has been no actual filing of a ULAS tariff. Recent indications are that the commission may now be less inclined to attempt implementation of ULAS.

Wyoming—There is no SLC. Although primarily a single-LATA state, there are a small number of communities in a second LATA. Only AT&T is authorized as a facilities-based interLATA

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carrier, but there are authorized resellers. In the intrastate access charge tariff there is a CCLC mechanism (Order, General Order No. 51, Dkt. No. 9343, SUB 37 et al., February 21, 1985). There is no apparent active consideration of alternative NTS cost recovery plans.

An Analysis of Tapered Access Charges for End-Users

D. P. Heyman, J. M. Lazorchak, D. S. Sibley, and W. E. Taylor

Since the unbundling of carrier access services from long distance in 1984, interexchange carriers (IXCs) have been billed for the costs associated with carrier access—the connection between IXCs and their customers in the local exchange. Subject to rate-of-return regulation, carrier access is currently priced using a fully distributed cost methodology comprised of two distinct charges per minute of use: (1) an artificial rate element (the CCLC or carrier common line charge) designed to recover a portion of the nontraffic sensitive (NTS) costs of the local loop; and (2) traffic sensitive (TS) rate elements designed to recover TS costs of switching and trunking in the local exchange carrier (LEC) network. These rates total, today, approximately seven cents for every

Note: Opinions expressed in this paper are those of its authors and not necessarily those of Bell Communications Research, Inc., its owners, or clients.
An Analysis of Tapered Access Charges

originating and terminating minute of use. The NTS rate is
typically averaged, the TS rates are generally specific to the LEC,
and both are billed to the IXC.

These rates, both in level and structure, have been contro-
versial since their inception. Rate levels, for economic efficiency,
should be roughly equal to marginal cost. However, marginal NTS
cost is zero, and recent studies show that marginal TS costs are in
the neighborhood of one cent per minute. Hence, the level of car-
rier access charges may be on the order of seven times its marginal
cost.

In addition, the structure of carrier access charges has been
controversial, particularly in the manner in which NTS costs are
recovered. An efficient structure would recover none of these costs
on a usage basis; the current rate structure places them entirely on
a usage basis. However, simple marginal cost pricing may not be a
feasible rate structure for carrier access services. Historically, this
service has borne an uneconomic assignment of costs associated
with the provision of local loops, and it has proved politically
difficult to reverse this flow of funds from a few large users to many
local subscribers. In addition, there may be economies of scale in
the local loop, in which case marginal cost pricing will not recover
the firm’s cost of providing service. The efficient pricing solution
to both these problems has been some form of Ramsey pricing.
However, for segments of the access market which are competitive,
such deviations from marginal cost may not be sustainable, and
the FCC has been reluctant to extend the monopoly franchise into
carrier access. For parts of the market which may be a natural
(or unnatural) monopoly, some form of Ramsey pricing may be
able efficiently to sustain a subsidy flow. However, the rule
raises a higher proportion of the deviation from marginal
cost pricing from relatively price-elastic services, which in this
case is residential access—the very service for which a subsidy is
sought.

The industry has not been reluctant to offer solutions to this
problem. Among recent filings are two plans which propose forms
of a declining block tariff for carrier access charges. The FCC’s
on the NYNEX proposals has centered on two largely independent
issues: (1) the feasibility and appropriateness of end-user billing
of access charges and (2) the economic consequences of tapered access
charges. Most of the debate involves the first issue, for end-user

billing of access charges raises such important issues as customer
control and contact; the inclusion of TS charges—particularly
transport—in the end-user charges; the effect on national aver-
age interstate toll rates; and the effect on other members of the
mandatory carrier common line pool.

In the next section of this paper, we will provide some per-
spective on these issues. However, like Sherlock Holmes’s dog that
failed to bark, what is most significant in this list is what is miss-
ning, namely, discussion of an economic efficiency standard for pricing.
As noted in the FCC Open Meeting of November 25, 1986, the
issue of paramount concern in devising a system of access charges
ought to be economic efficiency, and very little information in this
debate was directed toward this topic.

In the following section, we consider economic welfare gains
achievable in the carrier access market by a shift to a nonuni-
form price structure such as that suggested in the NYNEX com-
panies’ filings. Of course, declining block rate structures are not
new in public utility economics; they have been a common (and
controversial) rate structure in electricity and gas for years.
In telecommunications, declining block tariffs for usage are familiar
(for example WATS), and such tariffs for carrier access have been
discussed since the beginning of the debate on access charges, pri-
marily as a means of recovering NTS charges on a usage basis
from large users without encouraging uneconomic bypass.

We believe this focus on tapers as a means to prevent by-
pass is misplaced. Even if one chose to ignore bypass or discount
its effects on aggregate welfare, there remain economic efficiency

gains that can be realized from a properly designed tapered tariff.
The analysis below is based on a new view of optional nonuniform
price structures (prices which vary with the amount of the prod-
uct or service purchased), of which declining block tariffs are a
special case. Originating in the seminal work of R. H. Coase, this
view stresses the potential gains in economic efficiency attainable
from a nonuniform price schedule relative to a constant price per
unit consumed. More recent work has demonstrated the possibil-
ity of devising nonuniform prices which not only increase social wel-
fare (relative to constant prices) but also make every consumer—
large and small—better off relative to his position under constant
prices. The major contribution of this paper is actually to calcu-
late such prices in a simplified but realistic setting.
Issues Raised in the Debate

A tapered access tariff billed to end-users is a radical departure from the existing structure of access charges, and the magnitude of that departure can be measured by the virulence of the industry’s response to it. In a rare showing of industry unanimity, nearly every interest group represented in the FCC Comment cycle on the NYNEX companies’ tariffs expressed disapproval. Later we will show that a tapered tariff similar to those proposed by the NYNEX companies improves aggregate welfare, and a closely related tariff can be constructed which makes all users (and the firm) better off. Given these characteristics of the proposed rate structure, the industry reaction appears puzzling; in this section, we will try to summarize the main elements of that debate.

End-User Billing

Billing the end-user for access charges may be very different from current practice, but it is not at all at odds with economically efficient pricing. Access is not a good desired in and of itself; it is an intermediate good—an input into the production of long distance services. And for efficient pricing, it is irrelevant whether those who cause access costs to be incurred pay for them directly or pay for them indirectly in their long distance charges.

A bigger concern with end-user billing per se stems from marketing considerations. If carrier access is purchased by the IXC and provided as part of long distance service (as is now true), then the LECs would have no direct contact with long distance customers. The LECs would, in effect, provide a wholesale service which would be resold to customers by the IXC. If, however, access were sold directly to customers by the LECs, interexchange service would become the wholesale service which would be marketed or resold to end-users by the LECs (assuming changes in the MPJ, which currently proscribes such activity). Thus, end-user billing for access charges is at the heart of a struggle for retail market presence between local and long distance carriers, and the standard of economic efficiency has no relevance in deciding the outcome.

Interstate Rate Deaveraging

If long distance rates in some states include access and in some states do not, it is at least semantically true that interstate toll rates will be geographically deaveraged. However, what is important for consumer behavior is not the rate that the IXC charges; it is the total price of long distance service that the customer is required to pay. Under pure end-user billing, this total price would not be expected to change. In the proposals at hand, the only changes in the total long distance price would be due to the taper in the originating access charges, so the average total long distance price paid would remain the same, averaged across all customers in a study area. In these circumstances, it is difficult to understand how adoption of a tapered end-user access plan would cause average total toll rates to differ by study area.

Settlements with the NECA Pool

Currently, the carrier common line charge is nationally averaged, and earnings on the associated investment are pooled among all LECs. If an exchange carrier were to use an alternative plan while mandatory pooling were in effect, some mechanism(s) would have to be found to interface between the exchange carrier and the pool. While the NYNEX plans speak of keeping the pool “whole,” from an economic perspective, it matters a great deal how that is done. Different interfaces between companies and the pool create different incentives for pool participants and nonparticipants alike. A summary of the issues is given in previous work. There is no suggestion that devising a pool interface is an insurmountable problem.

Bypass

Most of the arguments favoring tapered tariffs (billed to the end-user or not) have proposed them as ways of extracting a contribution (above marginal cost) from large business customers without encouraging undue bypass. It is easy to understand the LECs’ private concern with preventing bypass, but to what extent does this private benefit reflect an increase in social welfare? In our view, bypass and switched access are two substitute inputs into the production of a long distance switched minute. Furthermore, the long distance technology is fixed proportions—a long distance minute of use cannot be produced without (roughly) two access minutes of use, but all forms of access are essentially perfect substitutes. Large customers will find dedicated access cheaper (whether it be private bypass facilities or LEC special access facilities), and
small customers will find switched access cheaper (whether it be aggregated through private access resale and sent through a dedicated facility to the IXC or aggregated through the LEC local network).

Customers at the margin are made no worse off by a change in access prices which induces them to switch methods of access from the LEC to a bypass provider or vice versa. It is the inframarginal customers whose consumer surplus is affected by changes in the relative prices of access provided by the LEC and by private facilities. In general, the appropriate measure of consumer surplus is—even for inputs—the area under the factor demand curve above the price line, and it is these areas which determine the economic efficiency of a given access tariff rather than the equilibrium quantity realized by either of the competing factors of production. This is the calculation we make in the next section.

Efficiency aside, society may wish to avoid investment in facilities required for uneconomic bypass or may wish to maintain a single, integrated national network. A tapered end-user access tariff can extract the maximum surplus from each customer type without encouraging uneconomic bypass. However, no surplus can be extracted from customers for which switched access (-priced at marginal cost) is not the most economic access alternative. For the largest customers, the marginal cost of access is surely zero: these are the customers for which dedicated access (with zero usage costs) is most economical. The marginal (usage) cost of serving these customers is zero, and the LEC cannot economically serve them using switched access. Hence, a tapered end-user tariff cannot preserve the network in its current form without pricing switched access below marginal cost for the largest customer group.

Resale

A minor problem with a tapered tariff is that since they are based on a form of price discrimination (the marginal price paid by different size users is different), they set up incentives for customers to aggregate their traffic before presenting it to the exchange carrier network. Just as the WATS tariff has given birth to WATS resellers, bulk discounts in access should give additional impetus to access resellers. However, if access resale (private aggre-
The Theoretical Setting

Suppose initially that there are two consumer types, Big (B) and Little (L), with demand curves as shown in Figure 1; at any price, Big’s demand $Q^B(P)$ exceeds Little’s demand $Q^L(P)$. Initially, both customer types face a flat-rate price of $P_0$ per unit. The firm earns a normal profit:

\[(P_0 - mc)(Q^B_0 + Q^L_0) - (NTS \text{ cost}) = 0\]  

(1)

Now give the two consumers a choice: Let them continue to buy at the uniform price $P_0$ or buy under a two-part tariff $(E_1, P_1)$ having a flat entry fee,

\[E_1 = Q^B(P_0)(P_0 - P_1)\]  

(2)

and a usage charge,

\[P_1 \text{ where } P_0 > P_1 \geq mc \text{ and } mc \leq P_2 \leq P_1 \leq P_0\]  

(3)

and $E_1$ is given by the sum of areas $a$ and $b$ in Figure 1.

Clearly, Little will stick with $P_0$; the increase in consumer surplus he would derive from the lower usage charge $P_1$ is given by the area $a$, which is more than offset by $E_1$, given in Figure 1 by the edged rectangle $a+b$. Big prefers the two-part tariff because $E_1$ takes only part of the increase in consumer surplus made possible by the lower usage charge, leaving him better off by the lined triangle $\Delta CS^B$. The firm makes a nonnegative profit from the two-part tariff because of demand stimulation induced by the lower marginal price: The increment $(Q^B_0 - Q^L_0)$ in Big’s consumption takes place at price $P_1 > mc$. The rectangle $\Delta PS^B$ represents increased producer surplus for the firm. Thus the firm as well as both customer types are better off facing the two-part tariff $(E_1, P_1)$ than facing the uniform price $P_0$; such a tariff is said to "Pareto dominate" the flat-rate tariff $P_0$.

As we see in Figure 2, what we have done is equivalent to constructing a declining block tariff with usage charges $P_2$ and $P_1$ and a break point at $Q^B_0$. The result is true in general: A declining block tariff can always be viewed as the lower envelope of a set of two-part tariffs from which consumers select their optimal consumption points. On that declining block tariff, the two consumer types select consumption levels $Q^B_0$ and $Q^L_0$.

Now suppose that there are three consumer types: Big, Medium (M), and Little. Their demand curves are consistent with the noncrossing assumption and are shown in Figure 3. We can construct a set of optional two-part tariffs—$(E_1, P_1)$, $(E_2, P_2)$—in the same way we did above:

\[E_1 = Q^B_0(P_0 - P_1)\]

\[E_2 = Q^L_0(P_0 - P_2)\]  

where \[mc \leq P_2 \leq P_1 \leq P_0\]  

(4)

Figure 1.

Now suppose that there are three consumer types: Big, Medium (M), and Little. Their demand curves are consistent with the noncrossing assumption and are shown in Figure 3. We can construct a set of optional two-part tariffs—$(E_1, P_1)$, $(E_2, P_2)$—in the same way we did above:
Using the same arguments as before, it is true that if Medium took \((E_1, P_1)\) and Big took \((E_2, P_2)\), then each would be better off than under \(P_0\), and the firm would make higher profits. However, there is a potential complication: Big might prefer \((E_1, P_1)\) to \((E_2, P_2)\). If he did, then the firm might make less profit from him under the optional tariff than under the flat rate \(P_0\), so that the firm might see higher profits under the flat-rate tariff. To ensure that the set of optional two-part tariffs Pareto dominates the flat-rate tariff, we have to further constrain \(P_1\) so that the lower entry fee that Big would pay under \((E_1, P_1)\) is offset—for his demanded quantity—by the higher usage charge. The decrease in consumer surplus that Big would undergo under \((E_1, P_1)\) due to the fact that \(P_1 > P_0\) is given by the area of the rectangle \((C + D + \Delta 2)\) in Figure 3. The reduction in the entry fee is given by the rectangle \((B + C + D)\). Thus, if \(B < \Delta 2\), Big will prefer \((E_2, P_2)\) to \((E_1, P_1)\).

We refer to this added complication as the incentive-compatibility constraint.

Note that by making \(P_1\) suitably close to \(P_0\), we can always ensure that this constraint will be met. As \(P_1\) approaches \(P_0\), \(\Delta 2\) rises while \(B\) declines. Thus, at some level of \(P_1\), the increased usage charge in going from \(P_2\) to \(P_1\) more than balances the reduction in the entry fee, inducing Big to select the tariff \((E_2, P_2)\) which ensures the firm higher profits from the optional two-part tariffs.
Summarizing the three-consumer argument, if
\[ E_1 = Q_0^m (P_0 - P_1) \]
\[ E_2 = Q_0^p (P_0 - P_2) \]
and the incentive-compatibility constraint,
\[ B = (Q_0 - Q_0^m)(P_0 - P_1) \leq 2(P_1 - P_2) \left[ Q_0^m + Q_0^p - 2Q_0^m \right] \]
is met, then the following happens: Big chooses \((E_1, P_1)\); Medium chooses either \((E_1, P_2)\) or \((E_2, P_2)\); Little stays at \(P_0\) and the firm makes higher profits than at \(P_0\). Relative to the flat-rate tariff \(P_0\), we refer to the set of optional two-part tariffs \((E_i, P_i)\) \(i = 1, 2\) as Pareto dominating and incentive-compatible (PDIC).

As shown in Figure 4, allowing consumers to choose among the set of three optional two-part tariffs---\((0, P_0)\), \((E_1, P_1)\), and \((E_2, P_2)\)—is equivalent to presenting them with a declining block tariff with usage charges \(P_0\), \(P_1\), \(P_2\) and break points \(Q_0^m\) and \(Q_0^p\). Proceeding in much the same fashion, with \(N\) consumer types one could construct \(N - 1\) optional two-part tariffs with the result that no economic agent would be worse off than under the flat rate \(P_0\) and some (including the firm) would be better off. This set of \(N - 1\) two-part tariffs would then be equivalent to a particular \(N\)-part declining block tariff which would Pareto dominate the flat-rate tariff \(P_0\).

**Consumer Welfare under Tapered Tariffs**

We assume a simple demand model that relates access demand for a customer of type \(i\) to the full price to the user of interLATA service, Thus \(Q_i = Q_i(r + P)\), where \(r\) is(159,115),(816,374)

Thus to compare the change in consumer surplus from moving from a flat rate to a tapered tariff, all we have to do is calculate the area under each consumer type’s demand curve above the marginal price he faces, subtract his entry fee, and subtract his consumer surplus under the flat-rate tariff.

For convenience, we assume that the equilibrium input demand function for consumer type \(i\) can be approximated by a simple iso-elastic form
\[ \log(Q_i) = \log(T_i) - e_i \log(P_i) \]
where \(T_i\) is a taste parameter and \(e_i\) is the price of elasticity of demand for customer of type \(i\). We also assume there are six different customer types corresponding to the six steps in the New York Telephone proposed tapered schedule.
To calibrate these demand curves, we require data on the distribution of usage and price elasticities by customer type. In Table 1 we present the current usage distribution for New York Telephone MTS customers along with average monthly usage for customers in each band, noting that this usage was generated by a flat rate IXC access price of approximately 7.5 cents per minute. From the six usage bands, we construct six user types with taste parameters $T_i$ given by

$$T_i = [\text{avg mou}], 0.0756$$

The price elasticities $e_i$ for the different customer types are derived from known long distance service price elasticities in the following way:

$$e_i = \frac{-\partial \ln Q_i}{\partial \ln P} - \frac{-\partial \ln q_i}{P}$$

which is the derived price elasticity of demand for IXC access. Usage elasticities by customer size class were approximated by combining econometrically estimated MTS and WATS elasticities in different proportions for different customer size classes. Given $e_i, T_i$ is easily computed from usage data in Table 1.

It is important to note that this view of access ignores efficiency gains or losses due to bypass; the access elasticity is merely adjusted to account for the fact that the end-user price includes an IXC component. To allow for the possible effects of increased by-pass competition, we analyze two alternative cases: one which has substantially higher price elasticities of demand for each user type at the base price and quantities (Alternative 1), and one which has sharply higher price elasticities for the larger users (Alternative 2). All three sets of elasticities are presented in Table 2, 23

We assume a marginal cost of access for each consumer type of one cent per minute, which represents an average of peak and off-peak marginal costs as reported in the New England Telephone filing. Note that this may overstate the true marginal cost of the largest group, since switched access may not be the most efficient form of access for some of these very large customers. The usage charge is for peak-period originating switched access for MTS services; the rate includes both TS and NTS components. We effectively ignore WATS demand in this analysis. 24

The efficiency effects of the NYNEX tapered tariff are given in Table 3 for the high elasticity case (Alternative 2). Compared to the flat rate of 7.56 cents per minute in the base case, customer types 1 and 2 are mildly worse off; however, together, these types comprise 99.5 percent of the customer population. Substantial welfare gains from the largest 0.5 percent of users generate a significant overall welfare gain. Overall firm profit rises by $0.007 per customer per month as compared with the base case, and total surplus increases by $1.14 because of the increased benefit to the very large users.

Calculation of Optimal Tapered Tariffs

We now compute sets of optimal two-part tariffs which maximize firm profits subject to the two constraints described above. 25
Table 3. Effects of the NYNEX Tapered Tariff, Alternative 2 Elasticities (relative to flat rate $0.0756)

<table>
<thead>
<tr>
<th>Customer type</th>
<th>NYNEX tapered tariff</th>
<th>Change in consumer surplus</th>
<th>Change in producer surplus</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$0.0661</td>
<td>$-0.29</td>
<td>$0.25</td>
</tr>
<tr>
<td>2</td>
<td>$0.0713</td>
<td>$-0.80</td>
<td>$0.89</td>
</tr>
<tr>
<td>3</td>
<td>$0.0444</td>
<td>$10.58</td>
<td>$10.36</td>
</tr>
<tr>
<td>4</td>
<td>$0.0352</td>
<td>$110.61</td>
<td>$90.93</td>
</tr>
<tr>
<td>5</td>
<td>$0.0302</td>
<td>$586.35</td>
<td>$590.93</td>
</tr>
<tr>
<td>6</td>
<td>$0.0209</td>
<td>$5,001.42</td>
<td>$4,134.29</td>
</tr>
</tbody>
</table>

Note: Change in aggregate profit = $0.006 per customer per month; change in consumer surplus = $1.135 per customer per month; and change in total welfare = $1.141 per customer per month.

First, each two-part tariff \( (E_i, P_i) \) must Pareto dominate the flat-rate tariff of 7.56 cents per minute. This is guaranteed by choosing

\[
E_i = Q_i(0.0756 - 0.0756) = Q_i(0.0756 - P_i) \tag{11}
\]

Second, given that \( (E_i, P_i) \) is designed to Pareto dominate the flat rate in this way, each customer type \( i \) must find it optimal actually to select this tariff and not some other \( (E_i, P_j) \), where \( i = j \). In the iso-elastic case, these two constraints are written:

\[
C1: E_i = T_i(0.0756) \tag{12}
\]

\[
C2: \frac{1}{(1 - \epsilon_i)} [P_i^{1-\epsilon_i} - P_i^1 - \epsilon_i] \geq E_i - E_{i-1}
\]

Hence the optimal set of optional two-part tariffs—the optimal taper—is generated by solving the following nonlinear programming problem:

\[
\max_{\{E_i, P_i\}} \sum_{i=1}^{n} [E_i + (P_i - 0.01)T_iP_i^{1-\epsilon_i}] \tag{13}
\]

(where \( d_i \) is the demand share of the \( i \)th type), subject to C1 and C2.

Table 4. Optimization Results, Alternative 2 Elasticities (changes relative to flat rate $0.0756)

<table>
<thead>
<tr>
<th>Customer type</th>
<th>Entry fee ($/month)</th>
<th>Usage charge ($/min)</th>
<th>Change in consumer surplus</th>
<th>Change in profits</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$0</td>
<td>0.0756</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2</td>
<td>$0</td>
<td>0.0756</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>3</td>
<td>$0.52</td>
<td>0.0752</td>
<td>0.82</td>
<td>$12.06</td>
</tr>
<tr>
<td>4</td>
<td>$29.18</td>
<td>0.0674</td>
<td>$0.82</td>
<td>$170.61</td>
</tr>
<tr>
<td>5</td>
<td>$342.17</td>
<td>0.0446</td>
<td>$65.00</td>
<td>$1056.60</td>
</tr>
<tr>
<td>6</td>
<td>$3,695.58</td>
<td>0.0238</td>
<td>$3,350.00</td>
<td>$1,056.60</td>
</tr>
</tbody>
</table>

Note: Change in aggregate profit = $0.50 per customer per month; change in consumer surplus = $0.50 per customer per month; and change in total welfare = $1.00 per customer per month.

For the NYNEX taper (T1) and elasticity Alternative 2, the results of the optimization are given in Table 4. The smallest two consumer types purchase from two-part tariffs which are indistinguishable from the flat-rate charge of 7.56 cents. Consumer types 5 and 6 receive deep discounts on the usage charge, in exchange for substantial entry fees. Recall that a characteristic of this tariff is that profit from each consumer type is no lower than it is under the flat-rate tariff.

Comparing the optimal declining block tariff to our stylized NYNEX tariff, we observe that the optimal tariff yields higher profits to the firm (roughly $0.50 per customer per month). This should come as no surprise, since the optimal taper is constructed by maximizing firm profits subject to the Pareto domination constraint. The NYNEX taper, in contrast, yields significantly higher consumer surplus than the optimal taper ($0.63 per customer per month more). However, it achieves this by not Pareto-dominating the flat-rate tariff of 7.56 cents, and a large number of customers are slightly worse off under the NYNEX tariff (relative to flat rate), while no customers are worse off under the optimal tariff.

In Table 5 we present results for the base case elasticities. The pattern is very similar to that obtained in Table 4. Profit
increases by 1.9 percent over the flat-rate tariff, for a dollar gain of $0.10 per customer per month, which is much lower than in the Alternative 2 elasticity case above. Consumer surplus weakly increases for each customer type, for an aggregate of $0.77, so that total surplus rises by $1.77 as compared with the flat rate. Again, this amount is significantly less than in the previous case. Note also that the optimal taper is much less steep in this case, where the price elasticity of demand for the largest customer type is much closer to that of the other customer types.

Under Alternative 1 elasticities, the same calculations are presented in Table 6. Customer types 1 through 3—i.e., stay on the flat-rate tariff. Types 4 through 6 purchase from two-part tariffs with substantial discounts on the usage charge, which falls to $0.0247 per minute for the largest customer type. The entry fees are substantial, as in the base case. Compared to the flat-rate case, profit goes up by $3.311 and consumer surplus by $2.97, for a total surplus gain of $6.28. Again, note that the higher price elasticity of demand results in a uniformly steeper tariff. Relative to the NYNEX tapered tariff under Alternative 1 elasticities, the optimal two-part tariffs generate $3.41 more profit and total surplus is $3.88 higher.

Conclusions

In this section, we have examined two separate issues in a stylized setting resembling the NYNEX companies’ controversial tapered access tariffs: (1) the extent to which particular tapers are economically efficient, relative to a flat-rate tariff; and (2) the characteristics and economic efficiency of a Pareto-dominating, profit-maximizing taper. We have responded to both issues in this paper, but the reader should be reminded that our calculations are preliminary and illustrative.

With respect to the first issue, it appears that significant gains in total surplus are achieved under a tapered tariff resembling the NYNEX companies’ filings or even under a less steep taper. Even ignoring the possibility of bypass (Base Case elasticities) and using the 12 taper, aggregate consumer surplus rises by $0.25 per customer per month. Under assumptions roughly approximating the NYNEX companies’ tapers and elasticities reflecting the possibility of bypass by the largest customer group, consumer surplus increases by $1.13 per customer per month.

A potential difficulty with our NYNEX-style taper is that customer types 1 and 2 are worse off under it than under a flat-rate tariff, and these customers comprise 90.5 percent of total accounts. Using the analysis described above, a profit-maximizing taper can be calculated which has the characteristic that no consumer type is worse off (relative to the flat-rate tariff), and the firm is better off. Such a tariff is presented in Table 4. It generates less total surplus than the NYNEX-style taper (but more profits) and has the possibly attractive characteristic that no economic agents are made worse off, relative to the current flat-rate tariff.

Note two final considerations in appraising this argument. First, the analysis ignores the fact that large customers are pre-
An Analysis of Tapered Access Charges

dominantly businesses, which respond to a reduction in toll rates by increasing usage, increasing production, and lowering prices of their products and services. Thus when we speak above of small customers being worse off, we are neglecting this important effect. Second, these calculations depend upon estimates of demand equations and usage for customers of different sizes, and these estimates are surely imprecise. However, varying the elasticities significantly has no effect on our basic conclusions that (1) lowering toll or access rates for large users relative to small users can produce significant welfare gains; and (2) for smaller welfare gains, end-user tapered access tariffs can be designed which help some size classes and harm none.

Notes

1. See, for example, New England Telephone's June 29, 1986 Access Tariff (F.C.C. No. 40) Filing, vol. 3, p. 1-22, Figure 1-1.

2. See, for example, the FCC's Third Report and Order in CC Docket 78-72 (released February 28, 1983), paragraphs 110-111, which explicitly rejects a monopoly franchise in carrier access as a market structure solution to the NTS recovery problem.

3. See, for example, the recent alternative NTS recovery plans filed by LECs and discussed in the FCC Memorandum Opinion and Order re: Petition for Waiver of Various Sections of Part 69 of the Commission’s Rules adopted April 3, 1986, released April 26, 1986 (the “Guideline” order).

4. The two NYNEXT operating telephone companies have proposed similar rate structures which bill both NTS and TS access charges to the end-user through a declining block tariff. New England Telephone and Telegraph Company, F. C. C. Tariff No. 40, filed June 26, 1986 (and modified in the October 1986 interstate filing); and New York Telephone Company, F. C. C. Tariff No. 41, U. S. West proposed in its October 1986 interstate access tariff filing to recover local transport costs from IXCs through a taper based on end-user usage.

5. See, for example, the FCC’s Fourth Supplemental Notice of Inquiry and Proposed Rulemaking in CC Docket 78-72 (released June 1, 1982) and the industry filings in response. For InterLATA, intrastate carrier access charges, see the tapered rate structure considered in Florida Public Service Commission Order in Docket No. 82535-TP (issued December 9, 1983), p. 15.


8. Except for the exchange carriers themselves.

9. Since access charges represent marginal costs to the IXCs, a change in access charges will be reflected—dollar for dollar—in the IXC price, assuming the interchange industry is competitive.

10. A study area is a LEC’s territory in a particular state. It is the smallest area for which access tariffs are filed.


12. Thus, very small users (who would be LEC customers at almost any set of relative access prices) would benefit greatly from a reduction in LEC access prices, while large bypass customers—induced by a change in LEC prices to rejoin the network—might be negatively indifferent.


14. Different tapered tariffs were filed by New England Telephone and New York Telephone. Calling our stylized tariff a NYNEXT tariff thus emphasizes that it does not precisely correspond to any filed tariff.

15. In this section, “flat rate” denotes a structure with a constant price per minute of use, independent of the amount of usage.

16. There is probably general agreement that the marginal cost of switched access is roughly invariant to the amount of switched access purchased.

17. Recall that the Public Utility Regulatory Policies Act of 1978 (PURPA) recommended the elimination of tapered tariffs unless they reflected the cost of service.

18. This is a simplified version of a more general result which appears in Willig, “Pareto-Superior Nonlinear Outlay Schedules.”


21. If medium takes (EJ, Pm) instead of (EJ, Pm), he is by definition—better off, and the firm must necessarily make more money than if he remained on (EJ, Pm).


23. Note that price elasticities derived from historical data have two defects if used for our purposes: (1) They represent the price elasticity of demand for switched long distance service, not for switched access, and (2) they were estimated from data in which there was no alternative to switched
access for long distance service. In addition, the constant price elasticity of demand assumption is probably unrealistic when substitution is predominantly driven by bypass.

24. This is technically unrealistic since the TS tapered rates apply to WATS usage as well as MTS and since the price elasticities of demand by band are derived from weighted averages of WATS and MTS own- and cross-price elasticities.

25. Recall that a set of optional two-part tariffs is equivalent to a particular declining block tariff.

26. Note that higher profits need not violate the rate-of-return constraint; the regulator can appropriate this amount for any project in the public interest.

27. But recall that total consumer surplus is still positive and large. This calculation understates welfare of small consumers since it ignores the flow-through effect of lower toll rates to large business customers on customers of those businesses.

The Effect of Technological Change on the TS/NTS Classification, Allocation, and Recovery of Central Office Equipment Costs

James W. Sichter

The telecommunications industry is experiencing rapid technological change. One of the most salient trends, the evolution to digital technology, is particularly evident in the rapid deployment of digital switching by local exchange carriers (LECs). In 1984, only 4 percent of the access lines provided by the Bell Operating Companies (BOCs) were served by digital switches, but by year-end 1986 that proportion may grow to 22 percent. The deployment of digital switching by independent companies has been even more aggressive. While the potential of new technology for both increasing productivity and providing a wide range of new services is well recognized, the effect of technology on the cost structure of the local network as well as on the established costing and pricing procedures in the industry has received less attention. The purpose of this paper is to explore that issue, focusing particularly on the effect (or, as it turns out, the seeming effect) of digital switching technology on the mix of traffic sensitive (TS)
and non-traffic sensitive (NTS) costs in the local network and, relatedly, its implications for jurisdictional separations procedures and access pricing.

The following section will provide the necessary background by describing the current procedures for the classification, allocation, and recovery of central office equipment (COE) costs. The next two sections offer a more critical examination of how digital technology effects and, indeed, undermines these procedures. The last section will explore in greater detail some of the major costing and pricing issues raised.

The Classification, Allocation, and Recovery of COE Costs

Under existing separations procedures, COE investment is subdivided into eight categories. Of particular interest here is Category 6, Local Dial Switching Equipment, which represents for local exchange carriers (LECs) in aggregate more than half, or approximately $12 billion, of the total annual COE revenue requirements. (See Figure 1.) In the separations process, Category 6 COE is further classified into NTS and TS components. Under the FCC’s current Part 67 Rules (the jurisdictional separations procedures), Category 6 NTS investment is allocated to the interstate jurisdiction on the basis of frozen SPF and TS investment on the basis of weighted Dial Equipment Minutes (DEM). The latter measures relative use of the local switch, and the weighting factor is intended to reflect the higher costs associated with toll versus local usage. Both the NTS/TS split and the DEM weighting factor are specific to technology types and size of the central office and were developed through sample studies conducted by the industry. The current factors used by LECs are exhibited in Figure 2.

Under Part 69 of the FCC’s Rules, Category 6 NTS costs are recovered through the per minute of use line termination charge, and the Category 6 TS costs are recovered through the local switching rate element, which also is a per minute charge.

Of particular note is the contrast, under existing rules, between the allocation and recovery of Category 6 NTS costs and the allocation and recovery of NTS loop costs. In its landmark Third Report and Order, the FCC adopted the logic that, because the costs of the local loop are caused by the demand for access and

<table>
<thead>
<tr>
<th>Category</th>
<th>Unseparated Revenue Requirement (Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. MANUAL SWITCHING EQUIPMENT</td>
<td>$407</td>
</tr>
<tr>
<td>2. DIAL TANDEM SWITCHING EQUIPMENT</td>
<td>179</td>
</tr>
<tr>
<td>3. INTERTOLL DIAL SWITCHING EQUIPMENT</td>
<td>447</td>
</tr>
<tr>
<td>4. AUTOMATIC MESSAGE RECORDING EQUIPMENT</td>
<td>401</td>
</tr>
<tr>
<td>5. OTHER TOLL DIAL SWITCHING EQUIPMENT</td>
<td>19</td>
</tr>
<tr>
<td>6. LOCAL DIAL SWITCHING EQUIPMENT</td>
<td>11,797</td>
</tr>
<tr>
<td>7. SPECIAL SERVICES SWITCHING EQUIPMENT</td>
<td>21</td>
</tr>
<tr>
<td>8. CIRCUIT EQUIPMENT</td>
<td>9,091</td>
</tr>
</tbody>
</table>

Figure 1. COE Categories and Industry Revenue Requirements.

### Table 1

<table>
<thead>
<tr>
<th>COE type</th>
<th>Office size (working lines)</th>
<th>Toll minutes of use weighting factor % intraoffice traffic</th>
<th>% Non-traffic sensitive book cost</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>0-50</td>
<td>51-100</td>
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<td>STEP-BY-STEP</td>
<td>0-5,000</td>
<td>2.3</td>
<td>2.3</td>
</tr>
<tr>
<td></td>
<td>Over 5,000</td>
<td>1.5</td>
<td>1.7</td>
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<tr>
<td>CROSSBAR</td>
<td>0-5,000</td>
<td>1.5</td>
<td>1.9</td>
</tr>
<tr>
<td></td>
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<td>1.7</td>
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<td>ELECTRONIC</td>
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<td>1.3</td>
<td>1.4</td>
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<tr>
<td></td>
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<tr>
<td></td>
<td>Over 10,000</td>
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<tr>
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<td>1.6</td>
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<td></td>
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<td></td>
<td>Over 1,000</td>
<td>1.3</td>
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Figure 2. Industry Factors for the NTS/TS Classification and DEM Weightings for Category 6 Central Office Equipment.
than usage-based access (and toll) charges.\(^3\) Correspondingly, the FCC modified the jurisdictional allocation procedures for NTS loop costs by ordering that, over eight years, the frozen SPF allocation factor be replaced with a uniform 25 percent gross allocator applicable to all LECs. When and if fully phased in, individual LECs' SLCs will be proportional to their underlying loop costs rather than reflecting the wide variances in LEC specific interstate SPF's (which range from less than 10 percent to as high as 85 percent). The FCC's decision to maintain the frozen SPF allocator for Category 6 NTS costs and to recover these through a separate rate element (rather than include them in the Common Line NTS cost category) was largely a matter of expediency, pending a reexamination of the NTS/TS classification and allocation of Category 6 COE. To put this into quantitative perspective, Category 6 NTS costs are, on an industry-wide unseparated basis, less than 30 percent of total Category 6 costs and about 15 percent of total industry NTS costs (see Figure 3). Recovering Category 6 NTS costs through SLCs rather than usage charges would require an average interstate rate of $.75 per access line per month.

<table>
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<tr>
<th>Total</th>
<th>Interstate</th>
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<table>
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</tr>
<tr>
<td>TOTAL CATEGORY 6</td>
<td>$9.19</td>
<td>$1.94</td>
</tr>
</tbody>
</table>

Figure 3. Industry Average Revenue Requirement Per Line Per Month (1984)

The Effect of Digital Technology

The rapid implementation of digital switching by LECs has profound ramifications under the current separations procedures. First, and of most immediate concern, is the effect on jurisdictional revenue requirements. As shown in Figure 2, as much as 75 percent of the Category 6 investment in digital offices is classified as NTS, compared to 25–35 percent in nondigital offices. Since Category 6 NTS costs are allocated to the interstate jurisdiction on the basis of frozen SPF, which is typically much higher than the weighted DEM allocator applied to Category 6 TS costs, digital implementation substantially increases the allocation of Category 6 COE costs to the interstate jurisdiction.

A rough approximation of this effect is provided in Figure 4. With an industry average frozen SPF approximately double the average weighted DEM factor, the higher percentage of NTS classification for digital offices increases the composite allocation of Category 6 costs for those offices to 24.5 percent—an increase of 40 percent over the 17.5 percent allocation, typical of nondigital offices.

In addition to its effect on jurisdictional revenue requirements, the deployment of digital switching has even broader implications for costing and pricing. Local switching equipment is a major component of local network costs; as shown in Figure 3, Category 6 revenue requirements are more than half as large as local loop costs. What digital switching technology portends, then, is a substantial increase in the proportion of local network costs that are NTS. In the context of access charges, this development suggests the need to re-examine the method of recovery of Category 6 NTS costs. Specifically, a fundamental premise of the FCC's access charge plan is that NTS costs should not be recovered from
interexchange usage charges. To the extent that local switching constitutes a large and growing category of NTS costs, it becomes important to reconsider whether those costs should be recovered, for example, through SLCs rather than usage-based access charges to interexchange carriers.

The apparent increase in the NTS proportion of local network costs also raises the issue of the economic desirability of local measured service. If, in fact, TS investment is becoming an increasingly smaller proportion of local network costs, any potential gains in economic efficiency resulting from local measured service would also seem to be diminished.

Reappraisal of Separations and Allocation

The implications of digital switching technology are substantial in terms of the current separations procedures for classifying and allocating Category 6 COE costs. Consequently, it is useful to examine the correspondence, or lack of it, between separations procedures and technological reality.

**NTS/TS Classification**

Of greatest interest is the NTS/TS classification of digital switching technology. Although a definitive analysis is beyond the purview of this paper, the available evidence clearly indicates that the apparent implications of digital switching for the NTS/TS proportions of local network costs are subject to serious question.

Most important, the current NTS classification percentages for digital offices, adopted in 1982, were based on earlier vintages of digital switches (most of which were deployed in small, rural exchanges). Those studies included a number of switches no longer being manufactured (such as Vidar). Conversely, some of the most widely used today (such as the No. 5 ESS and DMS 100) were either not yet in production or were not included in the study. Thus, the 75 percent NTS classification used in separations procedures for digital switches is not derived from an analysis of the generation of switches being deployed today. Indeed, it appears that the percentage is considerably overstated. For example, recent research indicates that for the No. 5 ESS the NTS component is 25–30 percent, while for the DMS 100 and GTD-5 it is around 50–60 percent.

Moreover, even if the NTS component in at least some digital switches is greater than in preceding generations, the implications for the overall NTS/TS mix of the local network require further analysis. For example, digital network architecture also alters the characteristics of outside plant. With remote switching units, the length of subscriber loops is reduced, and a portion of what is now the subscriber loop becomes, in many instances, TS trunk plant.

The overall effect of digital technology on the NTS/TS mix of the local network is, then, difficult to assess, at least quantitatively. Moreover, the continued and rapid evolution of technology (for example, ISDN, the digital telephone) could alter even more dramatically—and less predictably—the underlying economic characteristics of the local network.  

For our purposes, however, it is possible to draw two important conclusions. First, the current separations factor for dividing digital switch investment into NTS and TS components seriously lags technological developments. Second, the very classification process for digital switches is becoming increasingly difficult and arbitrary. Examples include distinguishing between the NTS and TS components that digital technology now integrates into a single piece of equipment, the allocation of switch software costs between NTS and TS functions, and the averaging across switches that, apparently, differ widely in their NTS/TS composition (such as the No. 5 ESS and the DMS 100).  

The implications for both separations procedures and access pricing will be explored in greater detail in the following section. Before doing so, however, two other aspects of the current procedures should be noted.

**The Toll Weighting Factor**

The toll weighting factor (TWF) used in the allocation of TS Category 6 costs was originally developed as a surrogate for more refined classifications of COE plant. The TWF is intended to reflect the costs of equipment used either more intensively or exclusively for toll (for example, trunks interfacing the switch with carrier systems). Based on sample studies, a ratio of toll to local costs per minute is developed for various switch types. This ratio—the TWF—is then used to weight toll usage in allocating Category 6 TS costs, thereby relieving LECs of the requirement to perform the detailed studies of each switch that would otherwise be necessary in order to identify the costs reflected in the TWF.
The applicability of a TWF in the allocation of digital switches is questionable, however. The increasing integration of functions characteristic of digital technology is eliminating many of the separate equipment items reflected by the TWF. And, as was the case with the existing NTS/TS categorization of digital switches, the current TWFs for those switches are the product of studies performed on earlier vintages in primarily rural applications. Clearly, the current TWFs for digital switches are obsolete. Moreover, with the increasing integration of functions in the newer generations, the underlying rationale for weighting toll usage is becoming untenable.

**Measurement of Relative Usage**

Another issue that has arisen as a consequence of digital technology is measurement of usage—and relative usage. Historically, the DEM factor has measured the use of the local switch, and the SLU (subscriber line usage) factor has measured the relative use of the local loop. A salient characteristic of these is that they effectively double-count intraoffice local minutes of use. This occurs because DEM and SLU separately measure both originating and terminating usage. Thus, as illustrated in Figure 5, a local intraoffice call of five-minute duration is counted, for separations purposes, as ten local minutes of use—five originating plus five terminating minutes. This methodology overweights local minutes of use in calculating the DEM or SLU measures of relative usage. That is, because local (intraoffice) minutes are counted twice, local usage as a percentage of total usage is higher than would be the case if local minutes were counted only once in the computation of relative use. Correspondingly, toll usage as a percentage of total usage—the DEM factor—is overstated, and proportionately fewer costs are allocated to the toll services.

Put somewhat differently, the current DEM factor imputes a higher cost to a local (intraoffice) minute of use than to a toll minute of use of a switch. This is a result of double-counting the former minutes. To use the example given in Figure 5, a five-minute local call is counted as ten minutes of use and therefore is allocated twice as much cost as a five-minute toll (or interoffice) call, even though both calls engage the local switch for the same amount of time—five minutes.

The apparent rationale for the double-counting was that, in older generations of technology, separate equipment was involved in the origination and termination of a call. For a digital switch, however, call set-up and processing are primarily software functions, and the costs of a call are the same whether it is local (originated and terminated in the same office), or toll, or any other interoffice call. It is more consistent with the characteristics of digital technology to measure usage, and relative usage, by counting a minute of use as a minute of use, rather than double-counting intraoffice minutes. This alternative measure, referred to as SMOU (switched minutes of use), simply measures the actual time the switch is engaged in establishing and maintaining a connection, whether for an intraoffice or interoffice call. Again, in terms of the example given in Figure 5, SMOU would count the five-minute local or intraoffice call as five minutes of use, the same as it would count a five-minute toll or interoffice call as five minutes of use.

The effect of SMOU is to impute the same cost per minute to all usage. From a jurisdictional allocation perspective, SMOU
allocates a larger proportion of local switching costs to the toll services than does DEM, a result that reflects the elimination of the double-counting of local or intraoffice minutes in the computation of relative usage. (To provide some insight into the magnitude of that effect, the interstate SMOU for United Telephone System companies would be approximately 17 percent compared to an interstate DEM of around 11 percent.)

In summary, then, the current separations procedures for classifying and allocating digital switches are of questionable accuracy if not fundamentally flawed. Indeed, those procedures are currently being comprehensively reevaluated by a federal-state Joint Board. Thus, it is relevant to examine policy alternatives for the classification, allocation, and recovery of COE costs.

**NTS/TS Classification, Separations, and Access Charges**

The important questions raised by the evolution of technology include not only its effect on the cost structure of the local network but also the very basic issue of how to measure minutes of use. The remainder of this paper will focus on only one of those questions: the NTS/TS classification, allocation, and recovery of COE costs.

**Separations Procedures and Economically Efficient Pricing**

In adopting its initial access charge rules, the FCC elected to treat Category 6 NTS costs differently than local loop NTS costs, pending a reevaluation of the classification and allocation of COE. While it is evident that the current separations procedures overstate the percentage of digital switches that are NTS, it is also clear that some portion of the local switch is, in fact, NTS.

The obvious implication of that factual observation is that the NTS/TS classification of Category 6 should be maintained, and that Category 6 NTS costs should, like local loop NTS costs, be (eventually) recovered through flat-rate SLCs. Before accepting that implication, however, it is necessary to examine the relationship between separations defined costs and economically efficient pricing.

Two points are pertinent here. First, the "costs" defined by separations procedures are fully allocated, average, embedded costs that do not measure the marginal cost of anything. Second, economically efficient pricing of usage requires that the price of usage be set at marginal cost and that, for a firm subject to rate-base regulation, any residual revenue requirements be recovered through fixed charges (or, more generally, from any source, such as government subsidies, other than usage charges). Such residual revenue requirements are not uniquely NTS in nature and could include TS costs (to the extent that embedded TS costs exceeded marginal costs) as well as common overheads of the firm.

In the context of separations procedures, then, the classification of embedded costs into NTS and TS components neither defines nor is a prerequisite for defining economically efficient pricing. Rather, the NTS cost classification contributes to economically efficient pricing only in the pragmatic sense that it is, or can be, used to define a portion of a firm's costs that will be allocated to the interstate jurisdiction but not recovered through usage rates. There is nothing intrinsically wrong in using the NTS classification or in flat-rate recovery of those costs as a means of reducing usage rates to levels closer to marginal cost.

However, there are two important caveats to this pragmatic use of the NTS/TS categorization. First, again, separations procedures do not themselves measure the marginal cost of anything. Therefore, it would only be by happenstance that pricing usage only on separations defined TS costs (and recovering separations defined NTS costs through SLCs) would even approximate marginal cost pricing. Second, and more important, reliance on historical estimations of NTS/TS splits to drive industry pricing is particularly questionable in a time of rapid technological change. The difficulty of estimating and updating NTS factors for a rapidly evolving technology is amply illustrated by the example of digital switching technology discussed here.

Moreover, even if the NTS/TS split for new technology were accurately estimated and kept current, the fact remains that LECs have in place a mix of old as well as new vintages of technology. The composite NTS/TS split for that in-place plant could, therefore, differ substantially from the NTS/TS split characteristic of the current technology being deployed. Finally, the practice of averaging these factors for all switch types of a particular technology (for example, using one factor for all digital switches) destroys whatever validity separations defined NTS/TS factors might otherwise have in determining the marginal cost of usage. This practice, which was developed to avoid biasing a LEC's choice of switch
manufacturer, obliterates what are apparently significant differences in the underlying cost characteristics of individual digital switches (as indicated, for example, by the comparison between the No. 5 ESS and DMS 100 provided earlier).

In short, if the objective is to set usage prices at economically efficient levels, the reliance on separations defined NTS/TS factors to accomplish that objective is misplaced. Certainly, the preferable approach would be to measure marginal costs directly, independent of the separations classifications and allocations, and set prices accordingly. In the context of separations procedures, this alternative could be implemented by setting usage charges at marginal cost and recovering any residual interstate revenue requirement (regardless of whether those embedded revenue requirements were associated with NTS or TS plant) through SLCs (or flat-rate charges). The conclusion to be drawn from the preceding discussion is that the NTS/TS classification has no underlying economic significance. This is particularly so in the current environment, where it neither has been proposed nor is it politically feasible to recover Category 6 NTS costs through SLCs, and, therefore, whatever Category 6 costs are allocated to the interstate jurisdiction will be recovered through usage charges. From a practical as well as a theoretical viewpoint, then, maintaining the NTS/TS distinction for these costs has no intrinsic merit. Alternatively, eliminating the NTS/TS classification and jurisdictionally allocating all Category 6 COE costs on the same basis, such as relative usage, would have a number of benefits.

First, it would simplify and reduce the administrative costs of separations procedures by eliminating the need to classify plant and continually update the NTS/TS and TWF factors.

Second, it would correct the overallocation of costs to the interstate jurisdiction that results from the use of SPF. Moreover, eliminating the NTS/TS distinction and the disparate allocation of those two categories also eliminates incentives to bias investment decisions in order, for example, to take advantage of the increased interstate allocation of costs associated with a digital switch, even if that investment did not otherwise make economic sense.

Third, a usage-based allocator alleviates the problems associated with the usage-based recovery of costs allocated on the basis of a fixed allocator. The problem is that there is no single fixed allocator (such as the 25 percent gross allocator used for loop plant) appropriate for all LECs because of the wide variance in usage characteristics. For example, even if two LECs had the same underlying costs, their respective access rates, based on a fixed allocator, could vary substantially due to differences in volumes of toll usage. In the case of NTS loop costs, the problems created by the use of a single fixed allocator by all LECs do not arise because of the mandatory nationwide pooling of those costs. (However, if mandatory pooling is eliminated, the use of a 25 percent gross allocator for all LECs might have to be reexamined.) But to the extent that COE costs are recovered through LEC specific rates, a usage-based allocator would have the advantage of at least relating prices to underlying costs.

Finally, it is worth briefly pointing out two further ramifications of eliminating the NTS/TS distinction and the fixed allocator for NTS costs. From a LEC perspective, a fixed allocator has the advantage of discouraging bypass of the local switched network. Because, with a fixed allocator, interstate revenue requirements are determined independent of usage, bypass reduces the denominator (usage) but not the numerator (revenue requirements) of the rate development equation. Thus, an interchange carrier (IC) that bypasses the local switched network would reap immediate savings in switched access charges. But the savings related to the charges recovering NTS costs would dissipate when those charges are recalculated. That is, with a fixed allocator, the effect of a reduction in usage due to bypass is an increase in access rates (when those rates are recalculated) in order that LECs can recover their unchanged interstate revenue requirement from the smaller volume of usage. Presumably, then, ICs will recognize in their economic evaluation of bypass that they cannot permanently reduce the amount of NTS costs they are assessed through interstate access charges.

A fixed allocator also has a disparate effect on interchange competitors. Again, since interstate revenue requirements are determined independent of usage, the effect of stimulation or growth in demand is to decrease access rates. For an individual IC, however, the benefits in terms of access charge reductions from stimulating demand (through, for example, an optional calling plan) are a direct function of its market share; the greater the IC's market share, the lower is its "marginal NTS cost" of a stimulated
minute. Alternatively put, the effect of a stimulated minute of use is to reduce the rate for all usage, with the result that an IC with a large market share will reap greater savings (measured by the reduction in rates times its minutes of use) than an IC with a small market share. Consequently, AT&T, with its dominant market share, enjoys a considerable marginal NTS cost advantage over its competitors in the interexchange market. Allocating NTS costs on the basis of relative usage rather than a fixed allocator, then, has two effects. First, it makes bypass of the local switched network somewhat more attractive since a reduction in usage would result in a reduction in the amount of costs allocated to the interstate jurisdiction, leaving switched access rates essentially unchanged. Second, it would largely eliminate AT&T’s existing marginal NTS cost advantage over its competitors in the interexchange market.

Separations Charges and Jurisdictional Cost Shifts

One further twist to the issue of separations classification and allocation procedures must be recognized. Revisions in separations procedures alter jurisdictional revenue requirements, and to a large degree the adoption of revisions depends on whether the attendant jurisdictional shifts are politically acceptable. Such shifts loom large in the consideration of alternative separations procedures for Category 6 COE. Eliminating the NTS/TS classification and allocating all Category 6 costs on the basis of unweighted DEM would shift, on an industrywide basis, more than $1 billion, or approximately $3.79 per month per access line, to the state jurisdiction. These numbers, it should be noted, reflect only the shift from the interstate to the state jurisdiction. On the intrastate side, additional shifts from intrastate separations procedures are revised to correspond to interstate procedures (or, in states that have not formally adopted intrastate separations procedures, as intrastate access charges are reduced to “mirror” or closely approximate the reduced interstate access charges).

What is of interest here, however, is not only the aggregate or nationwide average effect but also the disparate consequences for individual companies. To take an extreme example, in one particular study area the effect of going to the unweighted DEM allocation is to shift almost $19 per month per access line to the intrastate jurisdiction.

Historically, such anomalous or extreme results from separations changes have not been of primary concern because those changes typically increased the allocation of costs to the interstate jurisdiction. With nationwide pooling, a substantial increase in at least a smaller company’s interstate allocation did not materially affect the pool and therefore met little resistance (least of all from the affected company). Reversing this process—that is, reducing or unloading interstate costs—is another story.

Over the past several years, a number of strategies for managing jurisdictional shifts have emerged. The principal methods employed to date have been to use transitions to spread the effect over a number of years and to provide additional support for companies with high loop costs.

The Joint Board proceeding concerning jurisdictional separations procedures for COE has elicited a number of proposals that go even farther. In effect, they propose that different costing procedures be used for large and small LECs as a means of minimizing or mitigating jurisdictional shifts. Put differently, there exists no single cost allocation methodology that meets the needs and concerns of all affected parties, and therefore the only means of reconciling those divergent interests is simply to use different cost allocation methods for different classes of companies. Specific proposals include adoption of a variant of weighted DEM for companies of less than 200,000 lines (while larger companies would use unweighted DEM); a high cost factor for COE costs; and a high shift factor to prevent large jurisdictional shifts for companies (regardless of their underlying costs). Whatever the merits of these specific proposals, they together raise two substantive points. First, they challenge the “one size fits all” approach to separations procedures, that is, the concept that procedures should be uniform for all companies. Just as many LECs are pushing for the elimination of mandatory pooling, company-specific alternative NTS cost recovery plans, and pricing flexibility, one can anticipate increasing pressure to move away from uniform separations procedures in order better to reflect companies’ widely disparate economic circumstances and cost characteristics. In concept, there is no intrinsic reason for requiring all companies to employ the same separations methodology (at least in the absence of pooling), although nonuniform costing procedures would intro-
duce some added complexity to the FCC's administrative review of tariff filings.

Second, and of broader import, the concern with jurisdictional shifts on a company-by-company as well as industrywide basis contributes enormously to the institutional inertia that renders it difficult to revise existing separations procedures. Even changes in allocation procedures that are widely accepted as appropriate can encounter considerable resistance because of their effect on jurisdictional revenue requirements. Thus, adapting separations procedures to reflect rapidly changing technology would appear to be a hopeless cause. That, however, is not necessarily a negative. For, to the extent that jurisdictional cost changes (that is, changes in the amount or proportion of costs allocated to the state and interstate jurisdictions, as opposed to changes in a company's total cost) play an important role in investment decisions and technology choice, it would be highly desirable to make separations procedures as technology-neutral as possible. The allocation and recovery of COE, as discussed here, clearly illustrate how separations can provide investment incentives unrelated to considerations of economic efficiency. On the one hand, a company (or regulator) primarily interested in increasing the allocation of costs to the interstate jurisdiction, and maintaining low local service rates, has a powerful incentive to convert to digital switching, even if that conversion is not otherwise economically justified. On the other hand, a company that could economically justify implementing a digital switch must filter into that decision the substantial increase in interstate access rates and the increased vulnerability to bypass that are also a consequence of that investment decision.

In this sense, then, divorcing separations procedures from technology-induced changes in the cost structure (such as the NTS/T6 split) of the local network not only may be the one feasible alternative but also the most desirable public policy option.

Notes
1. The five largest independents were 24 percent digital in 1984 and projected to be 48 percent digital by the end of 1986. Telephone Directory and Buyers Guide, 1985-86, p. 684
2. Paul L. Cooper, "Analysis of Alternative Jurisdictional Separations Procedures for Central Office Equipment," prepared for the NARUC Winter Meeting, Phoenix, November 1986. The industry numbers are for 1984 and were derived from the data submitted by LECs to the federal-state Joint Board in the Docket 80-296 proceeding addressing separations changes for COE.
3. Third Report and Order, CC Docket 78-72 (Phase I), MTS/WATS Market Structure, 93 FCC 2nd 241
5. It is worth noting that the separations definition of NTS costs is not entirely coincident with the engineering or economic definition. Part 67.138 (b) of the Separations Manual states: The cost of non-traffic sensitive equipment comprises the cost of those items of equipment used jointly for both exchange and toll services, the quantities of which are determined as a function of the number of subscriber lines terminated and which in no way are a function of the busy hour or total volume of attempts, calls, or messages offered to or switched by the office. To take one example, a line card in a digital switch is, in an economic or engineering sense, NTS inasmuch as it is provisioned on a per access line (or per group of access lines) basis and its costs are unaffected by a customer's actual usage of a line. The separations definition of NTS, however, requires that a portion of the line card be classified as TS to the extent it performs traffic- or usage-related functions. This definition, among other things, enormously complicates the classification process, since, for example, the lowest unit of pricing by the manufacturer is the line card itself, and therefore allocating that cost between NTS and TS functions is an inherently arbitrary exercise.
8. Cooper, "Analysis." The industry data, it should be noted, were for 1984; because of the rapid implementation of digital switching, especially by the BOCs, since that date, it seems likely that the actual effect would be considerably higher. Moreover, it should be stressed that, the effect of the unweighted DEM allocator is used only for illustrative purposes. As
previously discussed, SMOU would be a better measure of relative usage, at least for digital technology. Industry estimates of the effect of SMOU are not, however, available.

Comments

Nina W. Cornell

I have discovered that being a discussant is the least well-defined task anyone is ever asked to perform, and I think I have seen at least three models of how people do it. Some people come with their own paper, and they proceed to say three words about each of the papers on the panel and then discuss their own paper. Some people come, and one particular paper has aroused their ire or elicited a great deal of admiration. These types say three words about the other papers and spend twenty minutes going over the paper to which they have had a strong reaction. The third type tries to weave the threads together that come out of the papers and say something beyond. This may be synergistic or nonsynergistic, but they try to draw some other lessons out of all the papers. I found this a very particularly challenging task for me because all three types, in some sense, were appropriate.

First, I have a paper on the issue of access charge design, and I have left copies in the back of the room. I think this is an issue of great importance that has barely been touched on in this session. But I also have always felt that is a little bit unfair, so I am
primarily going to leave it to the paper that is in the back of the room. Anyone interested can read it. At the appropriate point in these comments, I will tell you what the paper covers, and that is it.

The second model was appropriate because one paper did arouse, I will not say my ire, but a great deal of focus. That was William Taylor's paper. I guess I have a different view of economic efficiency, and I mind a little bit when there is a lot of talk about socking it to the small user. I think economists do have something to say about that issue if you think about economic efficiency a little bit differently than he did. But I also did not want only to discuss my reactions to his paper; that is not quite fair.

Finally, the third model, that of trying to draw some threads together, began to be more and more appealing the more I thought about it. Although I must say my first reaction upon receiving these papers was that they do not have anything in common, except maybe the word NTS, occasionally. But I thought about it for awhile and decided they do have something in common, and that is the larger picture one can draw after one reads them, or at least the picture I drew after I read them, perhaps I should not make it any more general than that.

The first thing that became clear to me is that there is really a bugaboo the way Robert Nichols defined it. There is a great deal of what I would call angst about this issue. What are we going to do about NTS costs? Twenty-four states are examining this issue, saying, "gee, we want to change what we are doing about it, we are worried about it, we care about it, we are anxious about it." That, in itself, says a lot, that there is that much activity and anxiety. But the more I thought about it, particularly about James Schifer's paper, the more I realized what is really needed is a change in how we collect NTS costs, but in how we analyze the issues. We probably can wait for awhile for the NTS cost discussions precisely because sufficient changes at the FCC make it no longer necessary to follow those who think bypass is charging down upon us imminently. I never shared that view, but there has been enough change to take that wind away from the door for a little bit. What is needed is some change in how we start analyzing the issues before we get to how we are going to collect or not collect NTS costs or collect them differently.

I would like to start my focus on Schifer's paper and try to ex-

plain what led me to this conclusion. I asked his permission before, and, thankfully, he has told you I am going to supply conclusions. The copy I got from him had the heading "Conclusions," and that was the end of the paper; there was nothing beyond it. So I felt that I would take the liberty of trying to draw some broader conclusions than the ones he has drawn. I do not quarrel with those, or at least most of them, that I heard him say today, but I think some much broader issues come out of what he has said.

In reading the copy that was sent to me three things began to come together and said to me there is a very big issue sitting out here. One is that Schifer's paper is replete with evidence that the NTS and TS distinction is highly dependent on two things: (1) the choice of technology, and this goes down even to the local loop or something to that extent; and (2) how well it has been measured. I think his discussion about the 75 percent allocation of category 6 for digital switches over, I think, 2,000 lines, is potentially obsolete (and he gave some information about 5 ESSs and DMS 100s and GTEs) and shows how vulnerable these things are to changes in technology and how well we measure them and how differently. One's conclusions, if you are going to take these numbers and try to drive all the way through to some static measure of economic efficiency, are based on those particular numbers. If there has been an error along the way on which technology you measured or how well you measured it, all your conclusions are invalid. Because you cannot be certain that you have done it right.

He put up on a slide for you my favorite quotation: "What you have in the cost side of separation doesn't measure the marginal cost of anything." And that is absolutely correct. So all of this discussion about these costs are the basis for X, Y, and Z in terms of economic efficiency does not yield the marginal cost of anything, so you are not working off of measures of economic cost. If you are going to talk about economic efficiency, you ought to at least, at some point, begin there. You may still have to come back to a revenue requirement.

I would argue the revenue requirement is not economically efficient to anything. But, nonetheless, you ought to have started with real measures of economic cost, and we are right back from where I started. If you are going to measure economic costs correctly, you must first correctly identify the most efficient technology used in
the most efficient way. That is where you must start for measure of economic costs. Of course, the data that we use in this industry do not have any remote resemblance to that number or to that concept.

The third thing that I thought was very insightful in Sichter's paper, and something we should keep in mind, is that none of this is a static process. I do not recall the exact words, but he made a comment about incentives for choosing digital technology because it shifts costs into the interstate arena. In his oral presentation, he commented that some cases could go the other way; that people do not want to choose digital switching because it might put costs into the interstate arena labeled as NTS costs and that could increase by-passes incentives. But the important point is that whatever gets done is creating incentives for the various players in this whole process.

There are incentives for the LECs to make choices of technology based on how you price access, how you engage in the jurisdictional shifts, and how you decide what the LECs have to collect from their own customers—that is, end-users—versus what they can try to pass on to the wholesalers or corporations that use their network, particularly the interexchange carriers. Taylor made the point that in some cases there were also incentives for the interexchange carriers in all of this out of the way you design access charges. He was talking about it in particular, at one point, in terms of incentives for ordering capacity for access to the local exchange. The fact is, both of them are quite correct. All of these prices create incentives for the players, and it seems to me that this very important fact is being missed in much of the debate.

Returning for a moment to Sichter's paper, I would draw another conclusion. As I said before, it is probably not another conclusion, I have already foreshadowed or said it blatantly: The costs we are dealing with that must be recovered in this industry are not economic costs. So when you start to talk about collecting them efficiently, you already have a problem. But, second, because technology is changing, because incentives are changing, and because this is no longer a closed system, you can change what that size is, how much of the incentives are economic, how they get recovered, and so on. So you are not simply looking at the economic costs. Here is a known pile of uneconomic costs, and we will design some optimal tax to recover them, and everything will be fine. We can all go home. I think this is why I want to make a plea, perhaps after listening to Taylor, for a slightly different version of economic efficiency.

I appreciate welfare triangles, as they are called in the trade, I appreciate looking at consumer surplus. But where data analysis is so dependent, as it is here, on a series of assumptions about the shape of demand curves, about the nature of elasticities, and most important about market structure, then any attempt to compute the relative efficiencies of two or more price options is actually a meaningless exercise. This problem with his results is something that Taylor never talked about. The first two—the shape of the demand curves and demand elasticities—we know very little about in this very changing world in which we exist right now. Both the change in technology, which is altering the cost picture—that real marginal cost which should have been on his graph—and the changes in market structure are clearly changing demand curves and elasticities quite rapidly, because when you try to measure elasticity, you are also going to pick up the effect of having choices. Some people's elasticity can be measured, particularly if you are measuring the elasticity of demand for a particular firm's product. It seems to me, therefore, that kind of analysis is fraught with danger.

I applaud what he tried to do. I think he may well be right that there are efficiency gains from multiple part tariffs. I particularly applaud the attempt to make sure that no one is made worse off in the process. I think that occurs too seldom. I think, however, it is premature even to try to engage in any serious policy making based on that kind of analysis. I think what these papers really are arriving at, and particularly the lesson of Sichter's paper, is that much more attention needs to be focused at the policy level on how to analyze the problems, what it is that the policy makers want to have happen to the industry. In that regard I am back to incentives, because incentives matter a lot, and the steps taken by policy makers can have an enormous effect on what outcomes are going to take place and how the firms respond to them. I said I would tell you what my paper is about for those who are at all interested. I have gone through the various models that Nichols talked about and discussed the impact of choosing those models for access charge design on industry structure, on the likelihood of competition surviving in the interexchange market. I
think this is where some of the emphasis ought to lie for policy makers. It is not time to sit down and measure welfare triangles.

I now spend most of my time in front of state regulatory commissions, so I see this particularly from a state as opposed to an interstate perspective. But I would argue the same is true at the interstate level. When I look at what is going on, it is not at all clear to me that the interstate policy makers mean it when they say they like competition, because they surely are not doing what is necessary to have it survive. And I think that is where the emphasis ought to be at this point. We are still sorting out as a nation and as policy makers what kind of industry structure we think is in the best interest of the American people over the long run and what steps need to be taken so the incentives are created for players to have that kind of industry structure reproduce itself or to continue if it is already there. Despite the tit for tat assumption which is equal access and beyond, we have not yet reached equal access and are not going to for quite some time, at least based on what I have been able to see so far. So, in the case of interchange carriers, if it is to be a competitive industry, how these access charges are designed in this transition period is potentially going to determine what is done, and the consequences are likely to determine whether competition can survive in the long run in the interexchange market. And that, as I say, is what my paper talks about.

I think, however, another issue has received less focus and is implicit in the bypass debate. Some of the things said by Taylor relate to what kind of structure we want for what I will call the LEC industry. Is it, in fact, going to be the case that we are going to open up that part of the industry to more and more entry? Should that be taking place in bypass, of course, in some form of competition, at least for large users. I, as a residential user, do not see how bypass helps me, but if I lived in an apartment building and shared tenant services were allowed by my commission in the most efficient way possible (which is not to partition the switch), I could, indeed, have competition, or at least better efficiency in the way I am served for local exchange. Are these things going to 'happen'? Or are they going to be stopped? I think this is a very important question. One issue that lies behind Taylor's paper is that he assumes we have an industry in which those kinds of declining block or multiple part tariffs can survive and most likely under conditions of monopoly. Either there is a natural monopoly, which is to say it is truly an industry in which average costs are higher than marginal costs, so you need to have a declining block structure in order to recover total costs (but given that any other entrant would face that same cost structure, only one firm is going to survive), or there is a legal monopoly because we put up barriers to keep it a monopoly in order to permit this kind of cost recovery when the efficient structure would be simply marginal cost pricing for everyone.

I think my favorite statement in Taylor's paper was his reference to Sherlock Holmes. The interesting thing was the dog that did not bark, that is, what was missing from his paper. He left out what I think is one of the most serious problems currently with the tape red rate proposal, which may well in the long run have some efficiency properties worth looking at. I do not think we are there yet; you cannot use it on feature groups A and B. It has always been particularly ironic to me that it should be NYNEX, with the lowest percentage of FGD access, which proposed this particular plan, because it is the least suitable for NYNEX territories. Having said that, I wrote out a lot of points to be made about Taylor's paper; I think it is highly dependent on the structure of demand, on demand elasticity, and on the assumptions about industry structure that lie behind those curves that he put up in his graphs. If you change the industry structure, you could change the demand curves. If you have measured elasticity wrong, you have, of course, changed the demand curves. It is conceivable that the real world cannot satisfy the constraints that he put up there for economic efficiency, not just economically efficient, but everyone either as well off or no one loses, and some gain. I think we are not at a stage where we can measure those things well enough to know whether any such tariff is feasible in the real world. I think, therefore, it is a very good piece of work in an academic sense, but a dangerous trap for policy makers.

I go back to Sichter's paper as having the most profound lessons for policy makers. We still measure very poorly, very categorically very badly, and we have to deal with book data that have nothing to do with economic costs. In the search for economic efficiency, one should not be turning to very complicated models, as Sichter did in his paper when he discussed a way of dealing with the costs of category 6 and central office equipment. We should be
looking for efficient rules of thumb that do not involve everyone spending a great many resources to put together cost categories and categorizations that may well be obsolete even before the work is done and inaccurate all the way through. I would strongly urge that, in the process, issues such as industry structure, dynamic change, where we want this industry to be in the future, and the best way to provide the services people want should be the ones on which policy makers focus. I think it is premature to measure welfare triangles under demand curves.

Part Four

New Guidelines for Segregating Regulated and Unregulated Telecommunications Services
Cost Allocation between Regulated and Unregulated Services:
The Part X NPRM and Computer III Decision

A. Gray Collins, Jr.

The goal of the Federal Communications Commission (FCC) has been to develop and sustain a fully competitive telecommunications and information services marketplace. However, inefficiencies caused by the structural separation requirement as imposed by the commission's Computer Inquiry II decision hinder realization of that goal and prevent the introduction of new services and technologies which would otherwise benefit the general public in the form of more customer options and improved network efficiencies.

During 1986 the commission provided some very positive signals to the industry that it will allow the Regional Bell Operating Companies (RBOCs) to move closer to the goal of providing an integrated approach for meeting customer needs. These signals reflect optimism with regard to the future direction of the commission and of the industry. For example, substantial progress has been made toward elimination of the Computer Inquiry II structural separation requirement.
FCC Actions

In June 1986 the commission released an order in the Computer Inquiry III docket which allows the BOCs and AT&T to provide enhanced services without the arm’s-length separate subsidiary requirement, subject to certain nonstructural safeguards.1

More recently, the commission eliminated the requirement for structural separation for the provision of CPE.2 In addition, the commission has granted a number of waivers to the telephone companies. For example, Bell Atlantic has obtained waivers allowing the company to provide, without structural separation, Protocol Conversion, Digital Network Channel Terminating Equipment and to act as prime contractor in responding to competitive bids that include CPE.

The commission’s direction has been to establish safeguards to replace the structural separations requirement, and it has stated that the “non-structural safeguards” would have to be in place before that requirement could be removed. While regulators may believe that safeguards are necessary, they should also be concerned about the negative effect of some concerns also exist about the time delay caused by the regulatory process, by way of the development and implementation of these safeguards.

For example, in the June 1986 CI-III decision, some unresolved key definitional issues require more attention, especially with regard to the definition of basic and enhanced services. It is Bell Atlantic’s view that protocol processing should be defined as a basic service when it is provided in conjunction with basic communications services. The commission released a supplemental Notice of Proposed Rulemaking (NPRM) in June 1986 to address additional issues, including these definitional concerns, but there is still no decision.3

Nonstructural Safeguards

The nonstructural safeguards are the key to allowing RBOCs to enter competitive markets without the burden of the separate subsidiary requirement. These safeguards are similar but not identical to the requirements imposed on AT&T in 1985, when the commission allowed AT&T to provide CPE without a separate subsidiary. The commission specified four nonstructural safeguards in the CI-III decision and live in the November 1986 CI-II decision. Four of these are essentially the same. The “fifth” safeguard for CI-II requires the BOCs to file plans describing how non-BOC vendors will be provided an opportunity to market Centrex and other network services.

Following is a brief summary of the four primary nonstructural safeguards.

(1) The rules on Customer Proprietary Network Information (CPNI) define the requirements for the disclosure of customer information and require the RBOCs to make CPNI available to other providers at the customer’s request.

(2) The Network Disclosure requirement specifies at what point in the development of a technical standard the RBOCs must disclose information about network changes.

(3) Another safeguard requires nondiscriminatory access to the network. The FCC proposes to establish guidelines to ensure that network service orders associated with RBOC CPE and enhanced services sales are not given favorable treatment in the provisioning process. The FCC suggests that the current Centralized Operations Groups (COGs) be continued for this purpose.

The CI-III order further requires the development and implementation of Open Network Architecture (ONA) plans, to be filed with the commission by February 1988. This is a condition for full relief of the structural separation requirement for enhanced services. Essentially, this safeguard requires the companies to provide, under tariff, unbundled basic network services and features needed to support enhanced services. That is a very simplified explanation of a very complex process. It is important to recognize that the ONA plans must satisfy the needs of telephone companies and enhanced service providers. As a footnote, until ONA plans are in effect, BOCs and AT&T can offer enhanced services on an integrated basis by satisfying interim Comparably Efficient Interconnection (CEI) requirements.

One of the interim CEI conditions requires that certain CEI components be cost averaged. Bell Atlantic is concerned that the concept may be misapplied. It could result, for example, in smaller and/or new enhanced service providers subsidizing larger, entrenched enhanced service providers. Cost averaging also artificially raises Bell Atlantic’s cost of entry into this market. It not only is uneconomic but also disadvantages our customers and those of other potential enhanced service providers. The remedy to
looking for efficient rules of thumb that do not involve everyone spending a great many resources to put together cost categories and categorizations that may well be obsolete even before the work is done and inaccurate all the way through. I would strongly urge that, in the process, issues such as industry structure, dynamic change, where we want this industry to be in the future, and the best way to provide the services people want should be the ones on which policy makers focus. I think it is premature to measure welfare triangles under demand curves.

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The commission’s direction has been to establish safeguards to replace the structural separations requirement, and it has stated that the “non-structural safeguards” would have to be in place before that requirement could be removed. While regulators may believe that safeguards are necessary, they should also be concerned about the negative effect of some. Concerns also exist about the time delay caused by the regulatory process, by way of the development and implementation of these safeguards.

For example, in the June 1986 CI-III decision, some unresolved key definitional issues require more attention, especially with regard to the definition of basic and enhanced services. It is Bell Atlantic’s view that protocol processing should be defined as a basic service when it is provided in conjunction with basic communications services. The commission released a supplemental Notice of Proposed Rulemaking (NPRM) in June 1986 to address additional issues, including these definitional concerns, but there is still no decision.

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1. The Federal Communications Commission (FCC) requires the requirements for disclosure of customer information and require the RBOCs to make CPNI available to other providers at the customer’s request.

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this concern is the commission’s objective in other areas, namely, cost-causeative rate structures for all customers, not just enhanced service customers.

(4) The fourth safeguard requires the BOCs to implement accounting procedures for allocation of costs between regulated and unregulated activities of telephone companies. The FCC did not specify these accounting procedures in either the CI-II or the CI-III orders. Rather, they deferred treatment of these accounting issues to a separate docket, referred to as either the “Joint Cost Docket” or “Part X.”

Importance of Accounting and Allocation Procedures

The importance of the Joint Cost docket, in conjunction with the removal of the structural separation requirement for enhanced services and CPE, as well as its effect on all future unregulated activities of telephone companies, cannot be overstated. It will provide the basic framework for developing cost allocation and accounting principles which will determine whether telephone companies can move forward toward a more competitive environment. The costing methodology selected will affect market entry, service availability, network and operational efficiency, and perhaps the prices for unregulated services. If the FCC errs in its selection of a costing methodology, it will block the entry of competition in the telecommunications industry.

History of Joint Cost Docket

In order better to understand the Joint Cost docket, it is important to recognize its history and its interrelationships with other regulatory activities. This docket is closely tied to the rewriting of the Uniform System of Accounts (USOA), which requires that a new accounting system be consistent with the offering of both regulated and unregulated services. USOAR has been a topic of commission discussion for the past six years, and the separations changes that are made will affect the implementation of the Joint Cost Order.

In 1985, a Further Notice of Proposed Rulemaking in the Rewrite docket was released which proposed establishing a separate docket for dealing with accounting issues pertaining to unregulated and regulated activities. Specifically, the commission referenced a 1984 Telephone Industry Advisory Group (TIAG) discussion paper. The TIAG had been established to prepare and submit a proposal for a revised Uniform System of Accounts. In this particular discussion paper, TIAG addressed the cost allocation problem and the need to amend the USOA to include rules for allocating joint and common costs.

As the commission began deregulating services in early 1986, specifically, inside wire and interstate billing and collection, it indicated that adoption of generic rules for allocating common costs would be covered in a future proceeding. As previously stated, both the CI-II and the CI-III orders required accounting safeguards but deferred activity to a separate proceeding. All of these dockets reference Part X as being the cost allocation methodology for unregulated services.

Interim Methodologies

The commission recognized the need to develop interim accounting plans to allow unregulated services to be offered prior to implementation of Part X. For Protocol Conversion offerings, the Commission required the methodology identified in a previous docket, 81-893, for unregulated services to be provided without the arm’s-length separate subsidiary requirement. This procedure relied on the use of separate books of account for unregulated services. Based on commission orders, Bell Atlantic has used this methodology for some of its other unregulated services. For newly unregulated services, for example, enhanced services, the FCC has required that accounting and cost allocation plans be modeled after one of the options proposed in the Joint Cost NPRM.

Part X NPRM

The commission released the Part X NPRM in April 1986 to address joint cost allocation issues, affiliated transactions, and accounting. The NPRM encouraged telephone companies to submit cost allocation manuals, based on the commission’s proposals, and invited comments on these proposals as well as on specific issues, such as time reporting, on whether Part X should be applied before or after the jurisdictional separations process, and on at least twenty other issues. This long-awaited, much referenced
docket drew the attention of industry participants, state regulators, and other interested parties. In June 1986, 48 parties filed comments, and 42 parties responded to these comments in July.

Telephone companies, including the seven RHCs, GTE, AT&T, and Southern New England Telephone, filed cost manuals. The record consists of more than 3,500 pages. The FCC adopted an order on December 23, 1986. This order is important to the industry because of the need for certainty from the FCC. Telephone companies need these guidelines in order to develop their plans for future unregulated offerings.

NPRM Cost Allocation Alternatives

The NPRM proposed two methods for allocating common costs, one a separations approach based on historical usage, the other a service cost approach, a service-specific methodology based on projected usage. The separations method is similar to the process used today to allocate costs to the state and federal jurisdictions; the service cost method most closely approximates the approach adopted by many state regulators in ratemaking proceedings.

In the Notice, the commission recognized the infirmities of using separations based (that is, relative usage) allocators in cost studies and proposed the service cost option as an alternative. Specifically, the commission noted:

The separations-type procedures cannot properly capture the costs of nonregulated services, particularly those nonregulated services which use common plant differently from the way that same plant is used in providing regulated services.

Furthermore, despite its multiplicity of detailed cost categories and allocation factors, the Separations Manual does not represent an especially sophisticated or accurate cost allocations system. We do not contend that it assigns "true" economic costs to the jurisdictions, it incorporates unavoidable inaccuracies and intentional policy choices, and individual judgments.

The separations process allocates costs between the state and interstate jurisdictions. Anyone who is vaguely familiar with that process and its relative use allocators understands that once total company costs are taken through the separations process, they bear no resemblance to the economic costs of a service. The costs coming out of the separations process have lost their individuality and their relationship to specific activities.

For these reasons, it is strongly recommended that the Part X costing process precede the jurisdictional separations process in order to uncouple the two and allow the commission to proceed with another of its agenda items—the simplification of jurisdictional separations.

Bell Atlantic agrees with the commission's statements in the NPRM regarding separations and is encouraged by the fact that the FCC put forth the service cost option. Most of the industry supported this option and submitted cost manuals based on it. These companies also commented on the infirmities of the separations approach.

Concerns Regarding Cost Allocation Procedures

Regarding the cost allocation procedures, Bell Atlantic does not believe that a "cookbook" approach, such as the Part 67/69 rules, is the appropriate cost allocation approach to protect ratepayers. Adoption of general rules that provide implementation flexibility can meet the concerns of the commission and also permit companies to provide new unregulated services. There is concern that the commission may establish procedures that result in the assignment of so many costs to a regulated service that prices for that service would be forced out of the realm of competitive reality in order to cover those assigned costs. Customers would be denied new services or would have to pay artificially high prices for the services. This situation would prevent telephone companies from proceeding toward realization of fully competitive telecommunications markets. Cost causation should form the underlying principles of cost allocation.

Appropriate Methodology for Cost Allocation

All parties agree that maximization of direct assignment of costs is the first and foremost step in the cost allocation process. Quite simply, this means that costs directly associated with an unregulated product or service are assigned to that activity. This can be done through time reporting by employees and through identification of other dedicated expenses and investment. For Bell
principles cannot be overemphasized.

Putting aside the jurisdictional disputes, it would be desirable for the industry to have a common set of guidelines for identifying the total costs of unregulated services. To that extent that this framework is based on sound economic principles and not on arbitrary criteria, it would allow a uniform approach for costing unregulated services in both jurisdictions. This provides the appropriate economic incentive for the introduction of new services which would increase usage of the network. The FCC now has the opportunity to develop a basic blueprint for this process. If the FCC establishes guidelines which assign unwarranted and excessive costs to unregulated services, it may prevent telephone companies from entering new businesses, which are important to this country in the global telecommunications market. Telephone companies may also opt for continued use of the separate subsidiary, which may deny the public the benefits of integrated operations.

Another major issue of the Part X NPRM is the FCC’s proposed treatment for affiliate transactions. This is of real concern to the industry since the commission proposes an asymmetrical pricing approach that would require transfers of assets from regulated to unregulated affiliates, in lieu of list or tariff prices, to be at the higher of market value or cost. Transfers from unregulated to regulated affiliates would be at the lower of market value or cost. This approach discourages efficient transactions between affiliates to the detriment of ratepayers. Even if the affiliate were the lowest priced provider, the FCC’s proposal would discourage the sale since it would insist on the transfer occurring at cost. The industry proposes a more even-handed method, simply that transfers going from regulated to unregulated affiliates and vice versa be at market value, which includes list and tariff prices.

As an example, if a computer system were to be sold by a local telephone company to an unregulated affiliate, the commission’s proposed rules require that such transfers use the higher of book value or market value. Given the current regulatory environment that generally encourages depreciation lives to be in excess of economic lives, no transaction would occur in this case; it is simply cheaper for the affiliates to acquire such assets in the open market. Therefore, the local telephone company will continue using this computer system or sell it—still at market value—to a third party.
Bell Atlantic is opposed to transaction rules because the company already has practices in place which satisfy the commission’s concerns. Recent state audits and a recent NARUC audit summary report found that in Bell Atlantic “there is little chance that any significant cross-subsidization is occurring.” The report stated: “If the concept of a model structure for RHCs is relevant, then Bell Atlantic should serve as that model.” These practices were developed based on good business decisions and with the concerns of regulators and ratepayers in mind.

Future Concerns

As costing and accounting safeguards are being developed, it should be recognized that they cannot be so onerous that they do not stimulate new services and usage of the network. Telephone companies should not be penalized because of the myths and misconceptions of regulators, competitors, and the public, such as local exchange companies will use revenues earned by regulated operations to fund unregulated activities, local service will suffer because telephone companies pay too much attention to these unregulated activities, and local rates will rise.

The industry must assure ratepayers and regulators that they are not cross-subsidizing their unregulated activities. In addition, federal and state regulatory oversight, antitrust laws, the FCC’s complaint process, and affiliated interest statutes provide effective means for preventing telephone companies from engaging in cross-subsidization.

Another problem faced by telephone companies is the delay of the regulatory process. It is essential that the FCC proceed expeditiously toward resolution of this docket and others that will determine to what extent regulated telephone companies are able to enter competitive markets. Regulatory delay has prevented the telephone companies from introducing new services to meet customer needs and competitive realities. These companies are eager to work with the commission to resolve the regulatory concerns so the industry can economically implement procompetitive initiatives at both the state and federal level. This will allow telephone companies to stimulate network usage and to bring new services and technologies to more and more customers. Anything else falls far short of the direction of the industry and of the goals of the FCC.

Notes

2. On November 25, 1986, the commission adopted an order in CC Docket 86-79 (Furnishing of CPE by the Bell Operation Companies and the Independent Telephone Companies) which eliminated the CI-II structural separation requirement for the provision of CPE provided that structural safeguards are in place.
6. The FCC released the text of its Joint Cost order on February 6, 1987. The commission adopted a modified fully distributed cost allocation methodology which emphasized the principles of cost causation and economic efficiency.
8. Ibid. at ¶ 10.
10. Ibid.
New Techniques for Segregating Costs between Regulated and Unregulated Services and between Different Common Carrier Services

Mark A. Jamison and David Brevitz

Should regulators concern themselves with developing cost-of-service methods for regulated telephone companies? Some in the industry believe that in a technology-fueled competitive marketplace, regulation, let alone cost-of-service, is of little use. Whether the market becomes competitive in the long or short run seems to be subject to varying opinion.¹

Others who consider development of cost-of-service methods important (a group including the authors) tend to believe that telephone companies will retain substantial market power in the supply of some services, such as local service, despite the development of technology. Since telephone companies will for some time to come be involved in competitive as well as monopoly markets, it is important for the sake of full development of competition in competitive markets, and full protection of consumers of monopolistically provided services, that all costs attributable to competitive services and an appropriate share of corporate overheads be allocated away from regulated monopoly services. Increasingly, regulators must bear in mind and complementary burdens of ensuring that telephone companies derive no undue anticompetitive advantage for competitive markets from possession of monopoly markets, and of ensuring that consumers of monopoly services pay rates which are not inappropriately burdened with costs of competitive ventures. Regulators need to have a holistic awareness of the effect of regulatory decisions regarding cost allocation and pricing on both monopoly service ratepayers and telephone company competitors. In this regard, regulatory and antitrust concerns have merged.

Historically, telephone cost-of-service methods have not been completely developed in state regulatory proceedings. The prime example is the use of residual ratemaking concepts, under which certain services besides local services are separately costed and priced, and the revenue requirement over and above the revenues generated by those services is recovered from local service rates. This places local ratepayers in the position of either benefiting or suffering from any errors in classification or allocation of costs. Given the orientation of telephone company management toward competitive markets and diversified business ventures, it seems that regulators bear an increasingly heavy burden to assure that costs arising from competitive activities are not included in regulated revenue requirements for local service.

Regulators need to consider that competitive market pressures can provide incentives for telephone company management to facilitate or even encourage shifting of costs from competitive markets to monopoly markets, where recovery on a residual basis is “assured” (unless regulators act to prevent recovery). These shifts or cross-subsidies can be subtle and not readily detected using accounting methods. But this makes the shift no less potent or damaging from the viewpoint of monopoly ratepayers or competitors. An example arises from the strategic nature of telephone company investment. Investment practices such as accelerated modernization may in certain cases impose costs on monopoly ratepayers for which little or no benefit is derived.² But investment may make strategic sense as the telephone company seeks to head off com-

¹Note: The opinions expressed are not necessarily those of the Kansas Corporation Commission.
petitive inroads into its market share and facilitate development of new, potentially competitive services.

In order to discourage competitive entry, provide enhanced services, and position themselves for the informational age they believe is to come, 3 Local Exchange Companies (LECs) are rapidly diversifying services, constructing new and more modern local facilities to convert to wideband networks for the provision of enhanced services, and, concomitantly, more quickly retiring older facilities. The U.S. Department of Commerce (USDoC) projects that regulated telephone companies will spend $25 billion in capital expenditures during 1986, an increase of 20 percent over 1984. 4 LEC construction alone increased nearly 20 percent between 1984 and 1985 and was projected to increase 9 percent in 1986. 5 The USDoC has also stated that digital electronic switches are replacing electromechanical switches at a rate of two per day. 7 According to USTA figures, LEC investment in plant since 1975 has grown at a rate two to four times higher than the growth rate of access lines. 8

This modernization to digital technology which yields the benefits of accommodating computer applications is occurring despite LECs' networks being used predominately for voice communications for which the older analog network has worked well. The demand for many of the services for which the digital network is being designed either has not yet materialized (and there exists the possibility that it may not) or is isolated to a relatively few large customers. Services for which demand is still conjectural include home shopping, banking, and other transaction services; electronic mail; utility meter reading; and residential voice over data applications.

An example of an existing service designed for a relatively few large customers would be digital centrex, a service many BOCs see as their flagship product as they move toward full ISDN and as their best means of keeping market presence with large customers, absent being permitted to provide digital PBXs and other enhanced services. Using digital centrex as a flagship product, however, has resulted in central offices being more quickly changed from analog technologies to digital (or in excess capacity under colocation scenarios). Through "digital synergy," then, the remainder of the network can be more rapidly converted to digital technology. This would be appropriate if the cost of the network upgrade were supported by the enhanced services being offered and projected to be offered. But without careful regulatory consideration of LEC costing and investment strategies, the increased ratebase and depreciation expense that occurs as a result of modernization may be thrown into a pool of common costs and spread to all services. This would cause the general body of ratemakers to be asked to pay for modernization as the "cost causers," even though their demand for simple voice transmission has not prompted the build-up in plant.

Accelerated network modernization increases the ratebase by definition. More construction means more plant, which means more ratebase. Accelerated investment also decreases service life, which can lead to increased depreciation rates. Since depreciation is often a major portion of LEC expense, 6 and requested increases in depreciation rates are also significant, local exchange ratemakers could be asked to cover costs which properly should be attributed to other services. Formulas which divide revenue requirement between services or classes of services (this includes separations) often work upon the assumption that all services are equally responsible for network costs and so divide those costs based upon relative use. Such measures do not identify cost causation, with the result that some costs can be inappropriately recovered through local exchange rates.

This problem can be made worse if local ratemakers are also to be responsible for funding the elimination of depreciation "reserve deficiencies," which are also related to accelerated modernization. Southwestern Bell estimates it has a $106 million deficiency in Kansas and hopes to recover that over four years. The deficiency would cost ratemakers $3 per month. 9

To the extent that the statements above seem academic and conjectural, or even to be casting aspersions on the honor and goodwill of telephone company management, an analysis of relatively recent history shows that monopoly markets may indeed be abused. 10 The power of otherwise rational incentives on managers can cause actions which benefit management and stockholders but which harm competitors and consumers in monopoly markets. These incentives should not be ignored or underestimated. Given the large proportion of joint plant utilized in provision of telephone services and the "arbitrariness" of any allocation of those costs among services, disputes over cost of service are subject to no final
Revenues Requirements Concerns

LEC s present an overall revenue requirement proposal to a commission when a rate case is filed. It includes a variety of costs and expenses. The LEC also submits proposed rates designed to recover that revenue requirement. This section address some concerns which should be considered in deciding whether certain costs are justifiably included in revenue requirements and, if so, where. The next section addresses more completely the analysis of rate proposals using cost methodologies.

Within the proposed revenue requirement, some costs require greater attention to identification and analysis, as compared to others. Some are and some are not identifiable within telephone company accounting systems. There are several examples.

Telephone companies are required to implement equal access for interexchange carriers. This requires upgrading and replacing various facilities at significant expense. For purposes of jurisdictional separations, a narrow definition of the equal access category has been ordered by the FCC, with a fairly broad allocation of those costs chosen. But from an intrastate cost-of-service perspective, this allocation may inappropriately leave local ratepayers responsible for paying certain costs under standard separations procedures. For instance, telephone companies are placing "equal access tandems" which also give those companies other abilities. These tandems can allow the provision of operator services and transmission and switching of high-speed data. Since the costs of these tandems are not included in the equal access allocation, but are only allocated to the interstate jurisdiction insofar as standard separations procedures require, further consideration needs to be given in state ratemaking proceedings to appropriate cost recovery. There may be a serious mismatch between the reason for incurring the costs of tandem switching (provision of equal access, operator services, and high-speed data handling) and the assignment of costs under separations procedures.

A second and related area is modernization of plant and its effects on rate base, depreciation rates, and depreciation reserves. It should be noted at the outset that there is nothing inherently wrong with modernization. The network has undergone continual improvement. Modernization becomes problematic when it is driven by competitive goals but costs monopoly ratepayers. In a competitive industry risks and incentives are appropriately aligned because consequences of a modernization program, either positive or negative, redound to shareholders and management, based on management and technology performance and on customer choice. Since telephone customers for local service do not have realistic options, it is up to regulators to discern when modernization has become excessive and prevent excess costs from being included in monopoly rates. This will involve analysis of LEC forecasts and rationale for investment.

A third area which will require study is the move to Open Network Architecture (ONA). ONA is fundamental in the FCC's Third Computer Inquiry to competition among enhanced service providers. It represents "equal access" to the network to those providers. Its development is likely to cause significant costs. These should be isolated and assigned to enhanced service users and providers. To the extent that significant current expenses are incurred, they should be capitalized as "organizational" costs for the new enterprise and recovered as revenue streams develop.

A fourth area is in regard to assessing the effect of competitive ventures on LEC cost of capital. A related issue is recognizing risk differentials between services for purposes of setting rates. LEC rate cases have been marked by requests for higher returns on equity due to increased business risk from competition. It is implied that this competition affects the existing portfolio of LEC services only. But the LECs are diversifying using a holding company structure, beyond telecommunications services into other ventures such as real estate, insurance, computer retailing, and advertising. It is the holding company's stock which is publicly traded. This stock generates market data regarding dividends and growth expectations which are used as the basis for determining
return on equity in regulatory proceedings. The market data by
definition reflect an ongoing assessment of holding company risk
vs. a vs. the market. To the extent that required rates of return in
regulatory proceedings have increased over the past several years,
it is reasonable and necessary for regulators to ask why. It is rel-
levant to question whether diversification has caused an increase
in the overall cost of capital and changes in capital structure, and
whether increased business risk (or competition/new technol-
ygy) uniformly affects all service categories. For example, are local
service revenues as subject to competitive attack as toll or access
revenues? The answer certainly seems to be “no.” If this is the
case, some risk differential should be reflected in the return figure
applied to the ratebases for those service categories for purposes
of determining revenue requirements.
A fifth area is in costs associated with affiliate transactions.
These transactions are wide-ranging and depend on the organiza-
tional structure of the LEC. Some LECs have more affiliated
subsidiaries than do others. Therefore, the transactions will vary
from “standard” sorts (such as Yellow Pages and Bell Communica-
tions Research) to more unique types (for example, procurement
functions and advertising). Some “transactions” occur which are
not costed. A prime example is transfer of management personnel
(with associated knowledge and expertise) to unregulated, com-
petitive subsidiaries.
For specific affiliate charges to the regulated LEC operations,
“cost causation” needs to be assessed. Research by the California
Public Utilities Commission into charges by affiliates has yielded a
list of several factors which should be considered in assessing cost
causation. (1) Would the function performed by the affiliate be
necessary if there was no holding company? (2) Does that func-
tion benefit the local regulated utility? (3) Does the local regulated
utility perform a similar function? (4) Does the function benefit
each regulated and non-regulated subsidiary equally? (5) Does the
function require the same amount of time to perform for each sub-
сидиary? (6) Does the function’s cost have a causative relationship
to any factors? Analysis along the lines suggested here will in-
dicate whether the LEC holding company’s chosen allocator for
assessing affiliate costs overcharges regulated operations.
The California and New York commissions have also developed
similar mechanisms for recognizing uncompensated benefits that
accrue to unregulated subsidiaries by virtue of affiliation through
the LEC holding company to the regulated entity. The above ex-
ample of personnel transfers can be augmented to include the rep-
utation, credit standing, and revenue and earnings stability of the
regulated entity. The mechanism is to impute revenues in a rate
case in the form of a “royalty” or “affiliate payment,” whether or
not those revenues are actually received.
These steps are particularly justifiable in light of regulators’
past experience. The Kansas commission has for many years
limited license contract expenditures of the Bell Operating Company
to one percent of revenues. The evidence in rate cases during those
years “showed that time after time the monopoly ratepayer was
asked to inappropriately fund Bell System image building, good-
will and its research, development and marketing for competi-
tive services, many of which Applicant will now offer through its
separate competitive subsidiaries.” In the divesture rate case,
the Kansas commission found evidence “that history will repeat
itself” in the operations of the newly formed Bell Communications
Research organization. Although Southwestern Bell “sim-
ply failed to appropriately describe the great majority of those
(BCR) projects in which it will participate,” it was nonetheless
clear that “some of these projects . . . will undoubtedly benefit
and support (SWB’s) unregulated activities.” Accordingly, the
Kansas commission disallowed a significant portion of BCR ex-
 pense and set out requirements for the applicant regarding future
claims for BCR expenses.
A sixth area of expense which requires scrutiny is marketing
and sales, whether direct or indirect. Given the orientation of LEC
management toward competitive services, activities ranging from
basic market research and strategic planning to direct sales pre-
sentations and proposals are becoming more important. As LECs
move into new lines of business, it is only logical to expect sales
and marketing expenses to be incurred in support. This is not
problematic in and of itself, but from a regulatory standpoint cost
causers should be cost payers in this regard. Analysis of LEC bud-
gets and organization, along with accounting information, should
be adequate to determine whether any adjustments to expense
allocation are warranted.
Criteria for Evaluating Costing Methodologies

Cost studies can be used for several purposes, but for the regulator, the purposes fall into two main categories: designing rates of individual services and attributing revenue requirement to services or groups of services. In the former, since costs of individual rate elements are sought, the studies are necessarily detailed, and existing plant and practices are generally taken as given. However, even though individual rate elements may appear to cover their costs as estimated by this type of study, that does not mean that the service as a whole is recovering all the costs that may properly be attributed to it. Determining that is the domain of the latter type of cost study, which is the topic of this paper.

Before describing the properties such studies should have, a word of caution is in order. Cost studies should not be the final word on rates. First, although some may be very good, there is always an element of imprecision. So it is appropriate and perhaps even necessary for the regulator to interject his or her judgment. Second, as follows in the discussion, there are often multiple and even conflicting goals which the regulator must consider in setting rates. Control of natural monopoly is not the only reason for regulation. Other goals, such as readily available service of reasonable quality and at reasonable rates, may be of equal significance and may not be achieved by a competitive market.

Subsidy-free Costing

An important property that should be looked for in a costing methodology used to attribute revenue requirement to services is that it should be free of cross-subsidization. That is not to say it may not be desirable in some instances for services to be “subsidized.” For example, S.C. Littlechild showed that local exchange rates for different classes of customers should be set so as to equate the customers’ net private benefits of having local exchange service with the social benefit of them having service. However, although it may be appropriate to design rates which are not free of cross-subsidization, cost studies should be free of subsidies so that any rate cross-subsidization is known and explicitly chosen.

The economic criteria for subsidy-free costing is well established in the economic literature. Simply stated, the amount of revenue a set of services is to recover should not be greater than their stand-alone cost, nor less than their incremental cost. Stand-alone cost provides the revenue ceiling, and incremental cost provides the revenue floor. The stand-alone cost of a set of services is defined as the total cost for the company of providing those services. Incremental cost, in this case, refers to the difference between the total cost for the company, given it provides the set of services in question in conjunction with its remaining services, and the total cost for the company if it were not offering the set. It is based on total service cost and should be viewed in the long run, the period in which all inputs may vary, so that the cost of the standards and all facility changes that this set of services has imposed upon the network are counted in the cost. Incremental cost, in this sense, is not the same as marginal cost nor the same as avoidable cost. Marginal cost refers to the extra cost of producing the last unit of a service, and setting price equal to marginal cost does not ensure that no cross-subsidies exists. Avoidable cost generally means short-run variable cost, which by definition is less than incremental cost. So the use of avoidable cost also does not ensure against cross-subsidization. The concept of subsidy-free costing brings up several aspects of cost studies, both theoretical and practical, that should be considered. (1) Studies should be performed for all services, not just nonregulated services, and methodologies should be consistent. (2) Market forecasts used for estimating costs and setting rates should be closely reviewed. (3) The relative risk of services should be explicitly considered. (4) Regulated operations should not serve to recover unproductive nonregulated investments nor to test competitive ventures. (5) Reasons for incurring cost should be identified whenever possible.

The first of these is that studies should not isolate costs for competitive services and residually cost monopoly services. Per-
haps equally important is that methodologies used for costing different services should be consistent. For example, basing loop costs for one service on last year’s cost or vendor’s cost plus installation, but using embedded costs for other services, could cause different costs to be identified for the same plant. As a result, one service could inappropriately subsidize the loop costs of another.

The second point (review of forecasts) is related primarily to studies used to set rate elements but merits mention for two reasons: the aggregate cost of providing the service is a function of the projected demand, and cost study results are often expressed on a per-unit basis to support some proposed rate. The timing of LEC investment may be affected by the market forecast. Since timing also affects costs, the market forecast may be critical to the estimated cost of services. Also, many forecasts are generally made based upon some assumption of price and, therefore, can turn into a self-fulfilling prophecy. For example, a service projected to cost $50 per month per central office would cost $5 per subscriber if the market forecast were ten subscribers, or $5.00 per subscriber if the market forecast were one hundred subscribers. A market forecast based on a rate of $5 might reasonably forecast ten subscribers, but a forecast based on a rate of $0.50 might reasonably forecast 100 subscribers. So the rate assumed in the forecast drives the subscriber forecast, which in turn drives the rate. This is an important consideration since which forecast (optimistic or pessimistic) is used by the LEC might be a function of the LEC’s desire to provide the service instead of the desirability of the service from a policy perspective.

The third aspect mentioned above is that the relative risks of services should be explicitly considered in a cost-of-service study. Higher risk presumably causes a higher overall cost of capital, if the service(s) is significant to the firm. If this is true, services which increase risk, primarily competitive services and new ventures, should increase cost of capital. That increased cost is part of the incremental cost of those services and should be explicitly incorporated into the cost of service. There are at least two methods of estimating the increased cost of capital. One is to quantify a risk premium for the riskier services, and the other is to use different capital structures for different services. (The two approaches could even be combined.) The latter is based upon the assumption that riskier ventures generally require a lower debt-equity ratio.

Regarding the fourth point, firms with monopoly services may attempt to insulate shareholders from some of the risk of competitive ventures by moving inefficient assets acquired for the competitive ventures into the regulated ratebase, or by using the regulated operations as testing grounds for new ventures. If a competitive firm embarks on a new venture which fails at least in part, the shareholders of the firm stood to reap the benefits and, therefore, must take the loss. A competitive firm does not have excess profits in other ventures that may be used to insulate the shareholders. The same is not true for regulated firms. Absent careful regulatory scrutiny, the regulated firm has the ability to take useful investment made for nonregulated services and add it to the regulated ratebase. This type of cross-subsidization may be prevented by requiring company investment analyses to see if the assumptions made and the scenarios studied were appropriate, and to see if the least-cost alternative, from the view of the monopoly customers, was chosen. (This type of investigation will be discussed at greater length below.) The other possibility, that monopoly operations might be used to test services to be provided in a competitive market, might be more difficult to detect but would still constitute cross-subsidization. Whenever a new service is to be offered, it is probable that hardware and software “bugs” would need to be resolved and that personnel would need to be trained. If that service were used by the regulated operations before being offered in the market, the costs of finding and correcting bugs and of training personnel would be born by the regulated services unless those costs were tracked and attributed to the competitive venture.

The last aspect mentioned above is the tracking of what services are driving what investment decisions. As stated earlier, LEC strategies affect their investment decisions, which in turn affect ratebase and depreciation. To find the cost of a service properly, then, the services which are being accommodated by the investment decisions should be identified and their effect in some way quantified. In doing this, several questions should be considered, including: (1) Why were the facilities placed and how are they projected to be used over time? (2) What service considerations have driven the engineering standards used for network design? (3) Would the costs have been incurred if some of the nonregulated or competitive services were not provided? These questions
are not exhaustive, but they do indicate the type that should be asked.

This tracking of the services or strategies driving LEC investment decisions is growing in importance given the increasingly competitive nature of some segments of the industry (while other segments remain monopolistic) and the rapid changes in technology that have occurred with the merging of communications and computer technologies. The reason is not simply the increased importance of preventing anticompetitive pricing, but also the greater incentive for and ability of LECs to subsidize competitive services with monopoly profits. With increasing threat of entry, monopolists may attempt to maintain their market dominance through price discrimination, cross-subsidization, creation of entry barriers, and diversification into service substitutes or potential substitutes for the monopoly products. The diversification can be done in a number of ways, including upgrading facilities and recovering at least a portion of the cost of the upgrade from monopoly customers; investing in integrated facilities, which makes it more difficult for regulators to identify costs for individual services; and using the monopoly position in one market to create barriers to entry in fringe markets to (1) regain monopoly profits lost because of regulation and (2) protect the monopoly market from competitive entry if cross-subsidization is occurring.

The incentives to use such strategies are sufficiently strong that the monopolist may tend to diversify into fringe services even in the presence of superadditive costs—the condition where separate firms could provide a monopolist’s services separately and at less total cost than the integrated monopolist. Research has shown that this has occurred with electric and gas utilities and perhaps also with the old Bell System and telecommunications in general. John Mayo found that electric and gas utilities have merged, even in the presence of diseconomies of scope, in order to decrease competition. David Evans and James Heckman were not able to find subadditivity of costs (the converse of superadditive costs) between local and toll in the Bell System from 1958 to 1977 and concluded that the Bell System had failed optimally to decentralize itself during those years. Melvin Fuss and Leonard Waverman found similar results for Bell Canada. This tendency of monopolists is troublesome and adds impetus to the need to identify costs since that may be the only ex ante means to protect the captive customers.

Other Criteria

Besides identifying subsidy-free costs, a costing methodology should (1) distribute the cost savings of joint production to all services; (2) not permit an innovation which decreases the cost attributed to one service to increase the amount of cost attributed to other services; and (3) send appropriate price and cost signals to the telephone companies.

Using stand-alone cost as a revenue ceiling and incremental cost as a revenue floor does not mean that allocation of the common costs is not significant. Indeed, establishing rates that would result in stand-alone cost would mean that those services were receiving none of the benefits of joint production and that the services priced to recover only incremental cost were receiving all of the benefit. It seems intuitive that all services should recover a portion of the cost savings that are presumed to occur with joint production, but an economic solution to the allocation of that saving appears to be lacking from the literature that identified the appropriate revenue ceiling and floor. Absent further research, an equal division of the savings between stand-alone cost and incremental cost appears to be appropriate.

Another general criterion for appropriate costing methodologies is that innovations designed to decrease the cost of one service should not increase the costs attributed to other services. If so, company managers might be inclined to make decisions not conducive to cost minimization. For example, if an innovation decreased a service’s use of a quasi-public input by 25 percent, the natural tendency would be to decrease the cost of the input attributed to the service by 25 percent. Given that, it would appear to the manager that the innovation would be profitable if its cost were less than the 25 percent. However, if on a total company basis the savings in cost of the input was actually equivalent to a 10 percent decrease, the innovation should be invested in only if the cost of the innovation were less than the 10 percent. Otherwise, the total cost of the company would increase with adoption of the innovation.

The last criterion to be mentioned for appropriate costing methodologies is that LECs should be permitted to seek devel-
Marginal cost, avoidable cost, and EDA do not meet the criteria for several reasons. Setting price equal to marginal cost does not prevent cross-subsidization. This is true in theory whenever there are economies of scale. It appears that it would be true more often in practice because of the departure of MC in practice from MC in theory. Marginal cost in theory is the change of the total cost to the producer in the long run if output increases or decreases by one unit. The theory does not lend itself to direct calculation because of assumptions, such as divisibility of inputs and certainty with regard to productivity of inputs, which either do not fit or are not known in the situation at hand. Applied MC tends also not to fit MC theory because the application is often short run rather than long run, is selectively applied, and includes only direct costs rather than the costs of all inputs that may be productive. In practice, setting price equal to MC also ignores the allocation of cost savings due to joint production and would not necessarily encourage cost minimization on the part of the LEC. Avoidable cost and EDA methodologies also fall short of meeting these criteria. Avoidable cost presupposes that the costed service is subsidized by other services. EDA inappropriately attributes all loop costs to local exchange service and identifies some costs as common which should be directly assigned. Many costing methodologies fall into the category of FDC, so it is difficult to make general statements. However, given the nature of these methods, that is, they attempt to distribute joint and common costs to all services, they do at least have the potential of being subsidy-free and of meeting the other criteria. But each method would have to be evaluated on its own merit.

New Methods Being Tried and Developed

A relatively new way to attribute cost that is gaining support is the stand-alone method. This primarily grew out of economic work on market structures at New York University, Princeton University, and Bell Labs in the 1970s and early 1980s, but its roots may be found in early FCC separations proceedings. The purpose of the study is to identify the stand-alone and incremental costs of groups of services (for purposes of developing subsidy-free costs) and equitably allocate the common costs to various services. Not all stand-alone cost studies have taken this last step, but it ap-
pears to be a natural one for the methodology and an area that merits further research.

Stand-alone costing may be one of the most important tools available to regulators today for allocating costs between regulated and nonregulated services. It is designed to identify cross-subsidization, allocate costs on a cost-cause basis, and distribute the benefits of joint production.

Despite its theoretical soundness, the method is not without its critics. It was argued a few years ago that it is not possible to perform stand-alone cost studies. That criticism is no longer valid since, as will be discussed below, stand-alone studies have been performed and others are in progress. Another criticism is that stand-alone costing is based on hypothetical systems which do not exist and which may not be viable. It is true that hypothetical systems, which exist only on paper are used to identify the nature of stand-alone and incremental costs—the costs necessary for identification of cross-subsidization. That hypothetical systems may not be viable is not important unless attributed cost equals stand-alone or incremental cost. However, properly used, a stand-alone study would not recommend that attributed cost equal stand-alone or incremental cost unless such an allocation were necessary for the most efficient collection of services to be economically viable. If that were the case, any cost allocation method would necessarily have to reach the same conclusion or cause the LEC to operate inefficiently. It has also been argued that stand-alone costing is inappropriate because it does not address individual customer situations, does not recognize scale economies, is long run in nature, and does not calculate marginal cost. These criticisms result from a lack of understanding of stand-alone costing. Given its purpose, to attribute revenue requirement to various services, it would be inappropriate to attempt to address individual customer situations or estimate marginal cost with a stand-alone study. Also, it is generally scope economies, not scale economies, that are important in allocating costs between services, and stand-alone costing explicitly addresses scope economies. Its long-run nature is a strength, not a weakness. In an industry changing so rapidly as telecommunications, the long run is not a particularly long time. Given that and the growth of the industry, the long run is generally the appropriate period to address. If revenue requirement were allocated on the basis of short-run costs there would be great difficulty establishing which costs were variable and which were fixed, and if LECs were permitted to recover all costs, cross-subsidization could occur.

Stand-alone studies in telecommunications have been done recently, and others are under way. The first was performed in Kansas in 1982-1983 for the Kansas Corporation Commission and ten other state commissions. The purpose was to serve as a prototype for future stand-alone studies and to develop a procedure for testing the hypothesis that toll subsidizes local exchange service. Four Southwestern Bell central offices in Kansas were examined—a No. 1A ESS, a No. 2B ESS, a Step-by-Step, and a No. 5 Crossbar—and the stand-alone and incremental costs of local exchange service and long distance service were calculated for each. Although most of the study results cannot be generalized, it was concluded that allocating costs on the basis of relative use confers greater benefits on toll service than on local exchange. Relative use would be an appropriate method of cost allocation only if (1) services made approximately equal use of plant and (2) standards of service were basically homogeneous.

A more recent stand-alone cost study was performed for the Wisconsin Public Service Commission in 1985 and presented in evidence in Docket No. 06-TR-5 (Part B). It was a category-cost-of-service study and looked at the stand-alone and incremental costs of local exchange, message toll (MTS and WATS), local private line, interexchange private line, and vertical services (custom-calling features and mobile telephone). Four central office types were studied: No. 1A ESS, No. 1 ESS, DMS-10, and No. 2B ESS. It was concluded that no service was collecting revenues above its stand-alone cost, but only local exchange and message toll were collecting revenues above their incremental costs. In other words, private line and vertical services were both being subsidized by local exchange and message toll services.

Several other stand-alone cost studies are being done or are to be done in the near future. In a recent Cincinnati Bell rate case the Public Utilities Commission of Ohio ordered Cincinnati Bell to file a stand-alone cost study with its next application for a rate increase. In Pennsylvania telephone companies are required by statute to submit stand-alone cost studies whenever requesting a percentage increase in local exchange rates greater than the overall requested percentage increase. The Public Utilities Com-
mission of South Dakota recently ordered a stand-alone cost study be done to aid in evaluation of some proposed legislation relating to telecommunications.40

A final note on stand-alone costing is in order. Commission staffs should be clear on the stand-alone theory before advising commissions on its use. Misapplied, the theory may be used as a defense for allocating greater costs to local exchange service, a conclusion that correct application of the theory would probably not support.41 That misapplication would generally come from two errors. First, it could come from extrapolating the results of a two-service case to cases with more than two services. In the two-service case, the range of subsidy-free rates is from the stand-alone cost of the service to the service cost of the service. However, when more than two services are considered, the range of subsidy-free rates is narrower, meaning that if a service does not collect revenues in excess of its own stand-alone costs it may be subsidizing other services.42 Second, the importance of allocating common costs might be ignored. It is often stated that allocation of common costs is arbitrary and perhaps even trivial. That may have been true at one time, but recent advances in economic and accounting theory have shown that the allocation of common costs is important from both economic and equity perspectives. Allocation of common costs can have significant effects on encouraging efficient operations by a firm. Also, since all services are equally responsible for the cost savings that have resulted from joint production, allowing all services to benefit from these savings would seem to be the only equitable solution for allocating common costs.

All stand-alone cost studies to date have assumed that all services are equally responsible for technology standards, plant replacement, depreciation, capital costs, and personnel costs, even though the authors of the studies have generally argued that the assumption is not correct. The use of that assumption has tended to bias the studies against the local exchange ratepayers since it is the more advanced services and the competitive services that are responsible for the standards, modernization, depreciation rates, risk, and so forth. It appears that at least one reason the assumption has been made is that sufficient studies and methodologies for identifying and quantifying those costs, and attributing them to the appropriate services, has been lacking. In response to that need, the Kansas Corporation Commission has initiated an investi-


tigation into LEC engineering economy models—computer models used by LECs to determine what construction to undertake and when to undertake it. The investigation is also to examine what LEC services tend to carry more risk than others and develop a methodology for attributing capital cost on the basis of that risk.

The rationale behind the engineering economy portion of the study is fairly straightforward. LECs undertake construction projects for basically four reasons: replace old plant, accommodate growth, reduce maintenance costs, and modernize. In almost all cases the decision to construct plant is supported by one or more economic studies. These are designed to answer the questions: (1) Why undertake construction? (2) Why do this type of construction? (3) Why do the construction now?43 By examining the studies the LECs have performed for their construction plans it should be possible to identify specifically what service and strategy concerns have prompted the LECs to undertake construction projects and what the difference in cost is between the new construction and the status quo. Since the economic studies are used for most construction, providing them to regulators is not particularly burdensome.

Another method of allocating cost of service is being investigated by the National Regulatory Research Institute (NRRI) with the cooperation of Southwestern Bell Telephone of Texas and the Texas Public Utilities Commission. This method would allocate embedded intrastate costs (as defined by separations) between various customer classes and services according to a peak responsibility method. The theory is that telephone company engineers base busy-hour usage for planning capacity for the telephone network. Given that, it should be possible to allocate capacity costs between services and customer classes based upon their peak and off-peak usage.44

The NRRI study is to result in a cost-of-service manual which will set out cost categories based on the Uniform System of Accounts and specify how those costs are to be allocated between services and customer classes. A draft of that manual has been published by NRRI. In it, telephone company services are segregated between private line service and message service. Private line services are divided into four categories according to interstate and intrastate, and interLATA and intraLATA. Message service is divided into fourteen customer classes and approximately thirty
service categories. The message service customer classes consist of four residential classes ranging from one-party flat rate to customer FX; seven business classes, including single-line flat rate, trunks, Centrex, customer FX, and official company use; and three miscellaneous classes consisting of public and semipublic coin and coinless, WATS, and mobile. The message service categories consist of services offered directly to end-users by the LECs themselves, including local exchange service (further divided into EAS, intraexchange, and intraswitch), intralATA long distance, 800 service, and operator services; interexchange carrier services consisting of the various feature group services; and operator services for which the LECs contract with AT&T.

The NRRI study is unique in its application of peak-load pricing theory to telephone services, although that application may be somewhat problematic. The theory assumes that the appropriate measure of cost causation is peak demand. That might be true if the technical standards for all telephone company services were homogeneous, but they are not. Standards and construction needs can vary and may not correspond to peak usage. The methodology may have application in allocating costs that are truly determined by demand for capacity, but other studies may be needed to identify what those costs should be.

The Colorado Public Utility Commission is developing a fully distributed category-cost-of-service methodology. It is being developed from a Bellcore model called Revenue Cost Analysis System (RCAS), which is a variant of EDA. By using the USOC codes of individual pieces of equipment, Colorado is directly assigning as many costs as possible. For those that cannot be directly assigned, it is identifying the function of each piece of equipment, identifying which services need those functions, and then allocating the costs between or among the appropriate services. Colorado intends to use NRRI's peak-demand methodology for making that final allocation, but the computer software will be left sufficiently flexible to permit other allocative criteria.

Other methods of attributing costs recently examined or under study include one being led by the California Public Utility Commission which involves NRRI, Ohio State University, Rand Corporation, and Berkeley. The study is using both econometrics and engineering studies to attribute costs to various services and should be completed in 1987. The staff of the Public Service Commission of the District of Columbia used econometrics to estimate the marginal costs of various telephone services, but the study was rejected by the commission because the model needed more development and testing.

Conclusion

The roles of the regulator and the LEC have become more complex with the arrival of competition in telecommunications. Whereas previously the LEC had only one type of market—captive customers whose preferences were expressed to the LEC via the regulator—it now operates in two types: competitive markets where the LEC must discern the preferences of potential customers in order to attract business, and monopoly markets where captive customers still exist and where preferences are still expressed via the regulator. Whereas previously the regulator oversaw the LEC's entire scope of operations, that scope is now reduced, but the part overseen is affected by, and in turn affects, the remainder of the LEC's business. So the regulator must consider the needs of and incentives of the LECs in both markets—the competitive and the monopoly—and act in a way that best serves the interests of both markets.

The regulator does not have the luxury of simply letting market forces work and assuming that customers will then best be served. A firm which operates in both monopoly and competitive markets has the same profit motives that a purely competitive firm does, but does not have the benefit of Adam Smith's Invisible Hand to direct it to act in the public interest. Only a part of the market mechanism called the Invisible Hand is at work for the LEC because of the heterogeneous market structure in which it operates. It is up to the regulator to be the missing part of that hand and to select regulatory tools that permit LECs to operate at their full potential, consistent with not unduly harming competitors or the monopoly ratepayers. The modernization of the LEC's network and the development of new services that have been prompted by present and future competition should not be hindered if they are cost effective. However, if they are not, both the competitive and the monopoly markets would best be served by their slowing.

The regulatory tools currently being used for allocating costs are not adequate to prevent the cost of the modernization and
the development of new services from being spread to ratepayers who are not the beneficiaries of the more modern network, or to send proper price and cost signals to LECs. Marginal cost, avoidable cost, embedded direct analysis, and accounting rules are not adequate for preventing cross-subsidization, especially where the technical needs of services are not homogeneous. Fully distributed cost has the potential of being adequate, but not without proper identification of what services are causing what costs and the allocation of those costs to the appropriate services.

Possibly the most effective tool regulators have for both preventing cross-subsidization and for sending the appropriate price and cost signals to LECs for construction and service development is stand-alone costing. Properly done, a stand-alone cost study identifies the appropriate revenue for services so that both monopoly and competitive services are not burdened with excessive costs, and it identifies the appropriate revenue floor for services so that no service is subsidized without the subsidy being explicitly chosen by the regulator. Stand-alone costing also provides economically rational methods for allocating common costs, although the authors would like to see further research done in that area.

Notes
1. One point of view of the long- or short-run nature of the development of competition is expressed in "Back to the Future," Federal Communications Law Journal 38, Number 2 (1986). The tone and content of the article indicate a general belief that "the proper long-term vision for domestic telecommunications" is "a competitive industry paradigm." "Fiscal deregulation is proposed in the interim. To the extent that some services are still regulated in the interim, measures are required "to ensure that the providers of those services do not engage in anti-competitive conduct. This task could be accomplished through the continued application of various nonstructural safeguards, including most prominently the employment of minimal cost allocation measures and accounting safeguards to prevent cross-subsidization of competitive services by those services characterized by short-run or long-run market power. This would ensure that neither taxpayers nor ratepayers will bear a disproportionate share of any joint and common costs of regulated and unregulated services" (p. 198, emphasis added).

2. Or investment may not be made where ratepayers would indeed benefit (as in some rural areas), since company strategic objectives require investment elsewhere.

3. Other reasons might exist, especially for small LECs which have few aspirations in the information age. However, even for those, the desire to provide enhanced or custom calling services appears to be an important factor in their decisions to upgrade.

8. For example, depreciation expense in 1985 for Southwestern Bell was 26.5 percent of total operating expenses.

9. Commissions may intend to fund extensive modernization for purposes of economic development. If a "reserve deficiency" amortization is chosen to do this, it is still relevant for rate design purposes to inquire which classes of customers and which group of services benefit from modernization, and whether the benefits are disproportionate among customer classes or service groups. Perhaps the entire "deficiency" should not be currently amortized or spread to local ratepayers on a blanket basis. Care should also be taken to define the extent to which modernization aids economic development, along with the scope and timing of necessary modernization.

10. Judge Greene's August 24, 1982, Opinion in United States versus American Tel. and Tel. Co. (552 F. Supp. 131 (1982)) was directed to "a determination whether a consent decree proposed by the parties is in the 'public interest' and should therefore be entered as the Court's judgement," rather than a determination and finding of fact regarding the antitrust charges against AT&T. Several statements in the Opinion do not represent findings that AT&T violated antitrust laws but are nonetheless significant. "A key feature of the proposed decree is the divestiture of the Operating Companies from the remainder of AT&T" (552 F. Supp. 160).

"In its complaint and in documents filed thereafter... the government asserted that AT&T monopolised the intercity telecommunications market and the telecommunications product market in a variety of ways in violation of the Sherman Act. The evidence that was produced during the AT&T trial indicates that, at least with respect to several of the government's claims, this charge may be well taken. It would be inappropriate for the Court at this juncture to draw definitive conclusions with regard either to the sufficiency of the evidence to sustain a finding of liability or to the validity of AT&T's various legal and factual defenses. The Court is not called upon, in this public interest proceeding, to render a final judgement on this case; indeed, not all the evidence that may bear on the issues has yet been adduced. It is not improper, however, for the Court to consider whether the state of proof at trial was such as to sustain this divestiture as being in the public interest" (552 F. Supp. 160). "Without
making definitive findings on any or all of the issues, it is certainly clear that—to the extent that the proposed decree is offered by the government on the premise that it will destroy the basis of past anticompetitive behavior—the Court would not be justified in rejecting it as constituting a remedy for non-existent anticompetitive acts" (552 F. Supp. 163).

11. MTS and WATS Market Structure and Amendment of Part 67 of the Commission’s Rules, CC Docket Nos. 78-72 and 80-286, FCC 86-6 (released January 7, 1986). The equal access cost category was limited to (1) the cost of converting end offices which serve competitive interex-
change carriers or (2) the cost of converting offices in response to bona fide requests for equal access. Excluded are such costs as tandem switching, the financial costs of advancing projects to meet equal access deadlines, and ongoing maintenance costs for generic software. Jurisdictional equal access minutes were selected as the allocator.

12. Several industry analysts have expressed concern over the BOEs’ and independent telephone companies’ abilities to compete profitably outside the telephone business. If this concern results in a perception of increased risk for the companies, the cost of capital for the companies should increase, and the amount of the increase should be attributed to the competi-
tive ventures. For a more complete discussion of the affects of competi-
tive ventures on local exchange companies, see David Cressler, Bryan K. Clark, and Li-Kung Feng, Unregulated Enterprises of the Bell Regional Holding Companies, National Regulatory Research Institute, Publication Number NRRI-85-22, March 1986.


17. Ibid., pp. 45-46. “During cross-examination it was discovered that com-
petitive studies, market assessment, basic market research, new product concepts, project data and video services research and radio satellites sys-

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to the monopoly services.

25. For example, during the early days of the telephone industry AT&T strengthened and protected its monopoly position by controlling long distance lines, controlling patents for basic telephone equipment, and investing in potential substitute technologies such as radio. See Gerald W. Brock, The Telecommunications Industry: The Dynamics of Market Structure (Cambridge, Mass.: Harvard University Press, 1981).


29. Baumol, p. 188.


31. A quasi-public input is one which, once procured, is available costlessly for the production of services making use of that service. The level of investment in the quasi-public input is determined by all the services that use it but is less than the sum of all their needs. An example would be the local loop, which, once constructed, is available costlessly for local exchange service, long distance service, and so forth.

32. William J. Pollard et al., Cost-of-Service Methods for Intrastate Jurisdictional Telephone Services, NRRI Report 84-13, National Regulatory Research Institute, Columbus, Ohio, April 1985, pp. 129-42. Fourteen of the 19 state commissions responding did not prescribe a particular cost-of-service study method to be used in ratemaking proceedings, but studies submitted to those commissions by LECs were generally EDA, MC, or avoidable cost studies. Of the five commissions which did have policies on costing methodologies, two used FDC, two used MC, and one used EDA in conjunction with a bottom-up study.


35. Brown and Sibley, Public Utility Pricing, p. 59. Another methodology which receives some attention is Ramsey pricing. Although not often explicitly advocated as a means of allocating costs, it is implicitly advocated under other guises. For example, those who favor end-user charges have done so largely on the basis of welfare gains. It is claimed that people tend not to drop local exchange service in the presence of increased rates, but a decreased carrier common line charge would stimulate long distance traffic, which would benefit society as a whole. Several problems with Ramsey pricing make it impractical as a cost allocation scheme. First, it does not always reward more efficient production techniques that decrease a firm's total costs. Second, it assumes that there are no consumption externalities and assumes equal welfare weights. Third, marginal cross-owned price elasticities of demand, and cross-elasticities of demand for all services must be known. They generally are not. Also, the elasticities should be for comparable market structures. Mixing service price elasticities for some services which are sold in monopoly markets with company price elasticities for services which are sold in competitive markets would not give comparable measures of welfare gains and losses. Fourth, there is no guarantee that Ramsey pricing would not result in cross-subsidization. There is nothing to keep the inelastic markets from paying more than their stand-alone costs or the elastic markets from paying less than their incremental costs. For more complete discussions of Ramsey pricing, see H.P. Young, "Producer Incentives in Cost Allocation," Econometrica 53, (July 1985); David R. Kamerschen and Donald C. Keenan, "Caveats on Applying Ramsey Pricing," in Danielens and Kamerschen, eds., Current Issues; and Brown and Sibley, Public Utility Pricing.

36. With respect to that, it is interesting to note that the LECs have not hesitated to use hypothetical bypass and bypass systems as evidence of the need for greater end-user charges, or to use hypothetical customer-owned private line circuits for their strategic planning.

37. Gabel et al., "Local Exchange Plant."


42. Basically, cost complementarities between services would have been ig-
nored, which would lead to services within a group each being individually charged their stand-alone costs, when the group as a whole could have a considerably lower stand-alone cost.

44. For a more complete explanation of the theory behind the NRRI study, see Pollard et al., *Cost-of-Service Methods*.

The Unbundling of Traditional Measures of Rate of Return by Regulated and Unregulated Services

*Ronald W. Metcalf*

The determination of a fair rate of return on debt and equity financial capital is an essential element of rate base/rate-of-return regulation. Regulated firms should be allowed to earn a rate of return that will be sufficient to maintain existing investor capital and attract new financial capital in order to finance plant, equipment, and working capital investments. However, to the extent that deregulation allows regulated firms to diversify into unregulated areas, the rate-of-return regulatory process becomes increasingly more complex. This paper explores methods for unbundling allowed rates of return by regulated versus unregulated services or activities.

The traditional regulatory equation is frequently expressed in the following form:

\[ R = E + (V - D)r, \]
where:

\[ R = \text{allowed operating revenues}; \]
\[ E = \text{operating expenses plus depreciation and taxes}; \]
\[ V = \text{value of plant, equipment, and working capital}; \]
\[ D = \text{accumulated depreciation}; \]
\[ r = \text{allowed rate of return}. \]

The rate-of-return variable, \( r \), reflects a weighted average cost of long-term debt and equity funds. That is, the regulated firm is allowed to cover the cost of its embedded debt funds plus be able to provide common stockholders with a fair rate of return on their invested capital. In addition to the component costs, the mix between debt and equity funds is important in determining the weighted average \( r \). In equation form, we have:

\[ r = kd(\text{wd}) + ke(\text{we}), \]

(2)

where:

\[ kd = \text{embedded cost of debt funds}; \]
\[ \text{wd} = \text{proportion or weight of debt funds to total investor capital} \]
\[ (\text{debt plus equity funds}); \]
\[ ke = \text{cost of equity funds}; \]
\[ \text{we} = \text{proportion or weight of equity funds to total investor capital} \]
\[ (\text{debt plus equity funds}). \]

In general, the allowed rate of return, \( r \), is viewed as being equal to the firm’s weighted average cost of capital and is the view used in this paper. It is common practice to estimate an overall (companywide) weighted average allowed rate of return, \( r \). As long as all (or nearly all) activities are regulated, a utility’s overall cost of capital reflects an appropriate allowed rate of return. This would hold even though the utility may have services, activities, or divisions with different degrees of riskiness and thus different costs of financial capital. In essence, the weighted average of these individual capital costs will form the utility’s overall cost of capital. However, if a substantial portion of the firm is comprised of unregulated activities that are more or less risky than the firm’s regulated activities, a use of the companywide cost of capital will missate the cost of capital for the regulated activities.

This paper explores the rate-of-return unbundling issue by first reviewing basic methods used in estimating the overall cost of common equity capital. Attention then focuses on divisional cost of capital concepts and the implication for separating regulated and unregulated activities. The last section considers capital structure factors in the unbundling process.

Methods for Estimating the Cost of Common Equity Capital

The basis for establishing a fair rate of return for regulated firms within the context of a risk-return framework is typically associated with the Bluefield and Hope cases. In brief, a fair return should be commensurate with that achieved by comparable risk firms. Furthermore, it should be adequate to maintain existing financial capital as well as allow the regulated firm to compete effectively for new financial capital.

Financial markets for debt and equity securities are perceived as being relatively efficient in a risk-return setting. Investors expect to be compensated for taking on higher investment risks. In other words, the expected return on any risky security is comprised of a risk-free component, and a risk premium component. It is reassuring to know empirical results show that investors do receive added compensation, on average, over the long run, for making riskier investments. For example, Ibbotson Associates, Inc. (1985), show that investors in corporate bonds have realized higher average rates of return than have investors in U.S. government bills or bonds. Furthermore, corporate common stock investments have produced higher average returns relative to corporate bond investments.

Several issues must be addressed in assessing a utility’s overall cost of capital. These involve determining the embedded cost of debt and preferred stock capital, estimating the cost of common equity capital, and identifying the proper capital structure mix. While the costs of debt and preferred stock are important, their
determination is generally straightforward. Consequently, the remainder of this section focuses on estimating the cost of common equity capital for the total firm. Capital structure mix implications will be discussed in a later section.

Three basic methods are used to determine the cost of common equity capital for regulated firms: comparable earnings, discounted cash flows, and risk premiums. The traditional application of the comparable earnings method focuses on accounting rates of return and begins by identifying firms of similar risk. Accounting rates of return for these firms then provide the basis for imputing a fair rate of return for the regulated firm. The basic problem with this approach is that investors base their decisions on market returns (cash dividends and stock price appreciation) and not accounting returns. Recent modified comparable earnings approaches have attempted to overcome some of the traditional method's shortcomings by focusing on market returns for firms of similar risk.

Basic DCF Approach

The use of the discounted cash flow (DCF) method began receiving wide usage in rate-of-return regulatory proceedings in the mid-1960s and continues today to be the one most used for estimating the cost of common equity capital. In brief, a security possesses an economic value because it is expected to produce a stream of future cash inflows in the form of cash dividends and price appreciation over time. However, the cash inflows will not be received immediately, and there is some uncertainty whether they will be received at all. Consequently, the present value of these expected cash inflows must reflect investor compensation for both the prevailing time value of money and the riskiness of the cash inflows.

The basic DCF model has been derived and described by many authors. Under conditions of a constant growth rate assumption, the model can be expressed as:

\[ ke = \frac{CD1}{MPO} + g, \]

where:

\[ ke = \text{cost of equity funds}; \]

\[ CD1 = \text{cash dividends expected in time period 1}; \]

\[ MPO = \text{current stock price (time period 0)}; \] and

\[ g = \text{constant cash dividends growth rate}. \]

The most difficult part of applying the DCF model is the need to estimate the long-run constant growth rate for cash dividends. Expert rate-of-return witnesses have recommended estimating growth rates on the basis of (1) historical growth rates in cash dividends and earnings per share, (2) internal growth rates based on the product of the return on equity and the percentage of earnings retained in the firm, and (3) financial analyst forecasts of earnings and dividend growth rates. Often some combination of these is used in practice to forecast future growth rates.

Table 1 shows a quick DCF approximation of the cost of common equity capital today for 15 firms operating in the telecommunications industry. Estimates are based solely on data contained in The Value Line Investment Survey. A couple of cautions are in order. First, dividend yield reflects a current yield and not necessarily one based on expected dividends. Second, the growth rates reflect Value Line estimates of growth in dividends and earnings over three to five years. An average of the two growth rates is used here for illustrative purposes.

The dividend yield currently averages 5.5 percent for the industry, with an average expected growth rate (average of dividend and earnings growth estimates) of 5.9 percent. This produces an average DCF-based cost of common equity capital of 11.4 percent for the telecommunications industry. In equation form we have:

\[ ke = 5.5\% + 5.9\% = 11.4\%. \]

This estimate serves only as a base for later discussion of financial capital costs by regulated and unregulated activities.

Risk Premium Approaches

The general form of the risk premium method is stated as follows:

\[ E(R_i) = R_f + R_p, \]

(4)
A specific version of the risk premium method is referred to as the capital asset pricing model (CAPM), used in rate cases since the beginning of the 1970s. The CAPM states the risk premium relationship solely in terms of systematic or market risk. In essence, this indicates the degree to which the return on a firm’s common stock covaries or moves with broad stock market returns. This index of systematic risk is termed the stock’s beta. The expected return on risky security $i$, $E(R_i)$, is expressed as follows:

$$E(R_i) = R_f + E(R_m) - R_f \cdot B_i,$$

where:

- $R_f$ = risk-free return;
- $E(R_m)$ = expected return on the market; and
- $B_i$ = beta or systematic risk for security $i$.

In brief, investors expect to be compensated according to how their investments are affected by changes in the overall stock market or macroeconomy. The larger the beta, the greater is the risk and the higher the expected return. Further discussion of market or systematic risk is contained in Melicher (1979).

Table 2 also shows a quick CAPM approximation of the cost of common equity capital today for the 15 telecommunications firms. Estimates are based on betas reported in The Value Line Investment Survey, a 7.4 percent long-term government bond rate, and a long-run compound average stock market risk premium of 6 percent. The long-term government yield is the average yield on 20-year U.S. Treasury bonds for the June-August 1986 period as reported in the November 1986 Federal Reserve Bulletin. The 6 percent market premium represents the approximate difference in the compound (not arithmetic) average rates of return between long-term government bonds and common stocks as calculated by Ibbotson Associates, Inc. (1985). An average cost of common equity capital of approximately 12.2 percent is indicated for firms in the telecommunications industry based on the above assumptions. In equation form, with an average industry beta of .80, we have:

$$E(R) = 7.4\% + [(6\%) \cdot .80] = 7.4\% + 4.8\% = 12.2\%.$$
Table 2. Approximate CAPM Estimates of the Cost of Equity Capital for the
Telecommunications Industry

<table>
<thead>
<tr>
<th>Utility</th>
<th>Common equity ratio</th>
<th>Beta</th>
<th>Expected Return</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLTEL Corp.</td>
<td>45.3%</td>
<td>.85</td>
<td>11.3%</td>
</tr>
<tr>
<td>Ameritech (RHC)</td>
<td>63.0</td>
<td>.85</td>
<td>12.5</td>
</tr>
<tr>
<td>Bell Atlantic (RHC)</td>
<td>62.0</td>
<td>.80</td>
<td>12.2</td>
</tr>
<tr>
<td>BellSouth (RHC)</td>
<td>62.5</td>
<td>1.05</td>
<td>13.7</td>
</tr>
<tr>
<td>Central Corp.</td>
<td>53.0</td>
<td>.75</td>
<td>11.9</td>
</tr>
<tr>
<td>Cincinnati Bell</td>
<td>67.0</td>
<td>.45</td>
<td>10.1</td>
</tr>
<tr>
<td>Comsat Corp.</td>
<td>46.0</td>
<td>.80</td>
<td>12.2</td>
</tr>
<tr>
<td>GTE Corp.</td>
<td>43.0</td>
<td>.90</td>
<td>12.8</td>
</tr>
<tr>
<td>NYNEX Corp. (RHC)</td>
<td>61.0</td>
<td>.85</td>
<td>12.5</td>
</tr>
<tr>
<td>Pacific Telesis (RHC)</td>
<td>57.5</td>
<td>.90</td>
<td>12.8</td>
</tr>
<tr>
<td>Rochester Tel.</td>
<td>55.0</td>
<td>.75</td>
<td>11.9</td>
</tr>
<tr>
<td>So. New England Tel.</td>
<td>60.5</td>
<td>.70</td>
<td>11.6</td>
</tr>
<tr>
<td>Southwestern B. (RHC)</td>
<td>53.5</td>
<td>.85</td>
<td>12.5</td>
</tr>
<tr>
<td>United Telecom.</td>
<td>41.5</td>
<td>.96</td>
<td>13.1</td>
</tr>
<tr>
<td>US West (RHC)</td>
<td>60.0</td>
<td>.80</td>
<td>12.2</td>
</tr>
<tr>
<td><strong>Average:</strong></td>
<td><strong>55.3%</strong></td>
<td><strong>.80</strong></td>
<td><strong>12.2%</strong></td>
</tr>
</tbody>
</table>


Note: RHC indicates the utility is one of the seven regional holding companies formed with the breakup of AT&T. Expected returns are estimated using beta, a 20-year U.S. Treasury bond rate of 7.4 percent, and an average market risk premium of 6 percent.

These quick CAPM approximation results are reasonably close to the ICP-based estimates. These equity cost approximations will be used for illustrative purposes throughout the remainder of this paper.

Divisional Cost of Capital Implications

Up to this point we have focused on estimating a firm’s overall cost of common equity capital, but many firms are comprised of a number of different divisions or activities. To the extent that some of these are riskier than others, the firm’s overall cost of capital reflects the weighted average of the divisional costs of capital.¹⁵

An Illustration

We can illustrate this concept with an example using the CAPM approach. For simplicity, let us assume a firm with an all equity capital structure (no debt) that is comprised of Division A (a low risk division with a beta of .60) and Division B (an average risk division with a beta of 1.00). Furthermore, the divisions are equally weighted (50 percent each) in terms of their effect on the overall firm. If we use a 7.4 percent risk-free rate and a general stock market risk premium of 6 percent, we can estimate the cost of equity capital for each division as follows:

Div. A: \[ E(R) = 7.4% + [6% (.60)] = 7.4% + 3.6% = 11.0% \]
Div. B: \[ E(R) = 7.4% + [6% (1.00)] = 7.4% + 6.0% = 13.4% \]

If these were separate firms, common stockholders would expect to earn an 11 percent rate of return for investments in Firm A and a 13.4 percent return on investments in Firm B. However, since they are divisions of the same firm, the market-determined cost of common equity capital will be for the total firm. The firm’s (A + B) equity costs could be determined as follows:

Firm (A + B): \[ E(R) = 7.4% + [6% (.60)] + [6% (1.00)] \]
\[ = 7.4% + 1.8% + 3.0% = 12.2% \]

In actual practice, there would be only one market-determined beta for the firm (A + B), and it would be .80 [that is .60(.5) + 1.00(.5)]. Using the CAPM framework we would have:

Firm (A + B): \[ E(R) = 7.4% + [6% (.80)] = 7.4% + 4.8% = 12.2% \]

Figure 1 depicts the firm’s overall cost of equity capital as a horizontal line at a 12.2 percent rate. A second line begins at the risk-free rate of 7.4 percent and increases as beta risk increases. Notice that the Division A and Division B costs of equity capital are indicated on this risk-return curve. Company managements often follow the practice of using risk-adjusted hurdle rates for
of business. This requires careful matching of services and products. Once these are identified, their betas are used to represent the division’s beta. For example, the low risk Division A discussed above would not have a directly calculable beta. Instead, one or more proxy companies might be identified, and their stock market betas of, say, .60 could be used to estimate Division A’s cost of equity capital as follows:

\[ \text{Div. A: } E(R) = 7.4\% + [6\%(0.6)] = 7.4\% + 3.6\% = 11.0\%. \]

Examples of the CAPM approach using proxy companies with applications to divisions of actual companies can be found in Van Horne (1980) and Harrington (1988). Furthermore, Fuller and Kerr (1981) collected pure-play betas for divisions of multinationals. They found that properly weighted proxy company betas closely approximated the overall market determined beta for these firms.

The second technique is based on the calculation of accounting betas. This method has appeal when it is difficult to match closely a division’s line of business with a publicly traded company. Instead of measuring a company’s stock price movement with a broad stock market index, movements in a division’s rate of return on assets are examined relative to an index of average asset returns for a large number of companies. By using accounting data, an accounting beta is calculated instead of a stock market beta. This accounting beta is then used as a proxy for the division’s stock market beta. However, studies show that accounting betas provide only approximations of market betas. As a consequence, this method must be used with care and caution. If, for example, we calculate an accounting beta of .60 for Division A, we would use the same CAPM approach that was used above to estimate the cost of common equity capital to be 11 percent.

Unbundling Regulated and Unregulated Activities

The divisional cost of capital concept applies equally well when discussing how to unbundle regulated and unregulated activities. For the sake of illustration, let us assume that 50 percent of a firm’s business is regulated and low risk, the other 50 percent unregulated and higher risk. Instead of using the firm’s overall cost of capital of 12.2 percent based on a stock market beta of .80
as the allowed rate of return, the cost of capital for the regulated activities should be used.

In a CAPM framework, we might be able to identify a group of publicly traded regulated firms that have all, or nearly all, their activities regulated. We then could compute an average beta for these proxy “pure-play” regulated firms and use it to determine the cost of equity capital for the regulated activities or division. As before, if this imputed beta is .60, we have:

\[
\text{Regulated Div.: } E(R) = 7.4\% + [6\%(.60)] = 11.0\%.
\]

We then could find the implied unregulated division beta (UnregB) by working backward from the firm’s overall equity capital cost of 12.2 percent and a market beta of .80, as follows:

\[
\begin{align*}
12.2\% &= 7.4\% + 3.6\%(.5) + [6\%(\text{UnregB})](.5) \\
12.2\% &= 9.2\% + 3.0\%(\text{UnregB}) \\
3.0\% &= 3.0\%(\text{UnregB}) \\
\text{UnregB} &= 1.00.
\end{align*}
\]

Thus, in the event that we cannot find proxy companies for imputing a regulated division or activities beta, we could try to estimate a pure-play beta for the unregulated division and then derive an implied beta for the regulated activities by using the approach presented above.

As the push for further diversification into unregulated areas continues in the telecommunications industry, it may become increasingly more difficult to find proxy companies. This may necessitate the use of accounting betas if analysts wish to focus directly on the regulated activities. Of course, as long as the unregulated activities are a small portion of the total firm and are not unusually risky, the cost of equity capital of the regulated activities will remain close to the overall firm’s cost of equity.

Although we have focused on divisional cost of equity capital concepts in terms of the CAPM, many can be applied to the DCF method. However, we would be forced to work directly with the DCF cost of equity capital estimates for a group of proxy pure-play firms because there is no specific DCF-related risk measurement.

For example, if the firm’s DCF-based cost of equity capital is 11.4 percent, and if regulated and unregulated divisions each represent 50 percent of the firm’s activities, we could derive the equity cost for one division and then solve for the other. For example, if the unregulated division is riskier and has an estimated cost of capital of 12.8 percent, then the equity cost for the regulated (Reg) division could be determined as follows:

\[
11.4\% = \text{Reg}(.5) + 12.8\%(.5) \\
5.0\% = .5\times \text{Reg} \\
\text{Reg} = 10\%.
\]

Another alternative might take the form of a generic cost of equity capital for regulated activities similar to the generic DCF-based cost of common equity capital being suggested by the Federal Energy Regulatory Commission. Because it is becoming more difficult to identify pure-play publicly traded regulated firms, it might be necessary to derive a generic equity capital cost based on a combination of telecommunications firms, electric utilities, and gas distribution companies. This generic figure then would be modified where warranted for unique utility operating or financial risk characteristics.

**Capital Structure Implications**

The allowed rate of return used in regulatory proceedings reflects not only the cost of debt and equity capital but also the mix of capital. Many analysts believe that optimal weights exist between debt and equity capital which will result in minimizing the firm’s weighted average cost of capital. Thus, it is also important to consider the capital structure issue in conjunction with the unbundling of regulated and unregulated services.

The CAPM provides a basis for examining the possible effect of capital structure differences on the cost of common equity capital and the weighted average cost of capital. Hamada (1969) recognized that the risk premium in the CAPM is a function of both financial risk and showed that the model could be rewritten as follows:

\[
E(R_t) = R_f + [E(R_m) - R_f] \times BU + [(E(R_m) - R_f)(1 - tr)(D/S)] \times BU,
\]

(6)
where:

\[ BU = \text{the firm's unlevered beta, which indicates only business risk}; \]
\[ \tau r = \text{the income tax rate, because debt interest is deductible for tax purposes; and} \]
\[ D/S = \text{the debt to common stock ratio for firm } i. \]

The other variables are the same as previously defined.

It has been further shown that the observed market-based beta \( (B) \) is actually a levered beta \( (BL) \) reflecting both business and financial risk and can be stated as follows:

\[ BL = BU \left[ 1 + (1 - \tau r)(D/S) \right]; \]

(7)

solving for the unlevered beta we have:

\[ BU = BL / \left[ 1 + (1 - \tau r)(D/S) \right]. \]

By first unlevering the betas of publicly traded proxy companies, it is then possible to revere the beta to reflect specific capital structures for different divisions within the firm.\(^{15}\) Table 3 shows a rough approximation of the unlevered betas for the 15 telecommunications firms. Value Line's estimates of the levered beta, the firm's income tax rate, and the common equity ratio are used. Although some of the firms used small portions of preferred stock in their capital structures, preferred stock was considered as debt for calculation purposes.

The average unlevered beta for the telecommunications industry is approximately .54, which indicates the industry's business risk relative to the overall stock market. If we again use a risk-free rate of 7.4 percent and a stock market average risk premium of 6 percent, the estimated cost of common equity capital associated solely with business risk is:

\[ E(R) = 7.4\% + [6\%(.54)] = 7.4\% + 3.2\% = 10.6\% \]

To the extent that most of the business risk of these publicly traded telecommunications firms comes from regulated activities, the 10.6 percent also would be indicative of the business risk for regulated activities. Furthermore, if we were trying to estimate the cost of equity capital for a regulated division of average business risk with a target common equity ratio of 55 percent and an imputed income tax rate of 42 percent, we would first revere the beta as follows:

\[ BL = .54[1 + (1 - .42)(.45/55)] = .54(1.475) = .80. \]

Now that we have a beta reflecting both business and financial risk, we can estimate the division's cost of equity capital as follows:

\[ E(R) = 7.4\% + [8\%(.80)] = 7.4\% + 4.8\% = 12.2\%. \]

<table>
<thead>
<tr>
<th>Utility</th>
<th>Debt-to-equity ratio</th>
<th>Income tax rate</th>
<th>Observed levered beta</th>
<th>Estimated unlevered beta</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLTEL Corp.</td>
<td>.238</td>
<td>.450</td>
<td>.55</td>
<td>.38</td>
</tr>
<tr>
<td>Ameritech (RHC)</td>
<td>.587</td>
<td>.450</td>
<td>.55</td>
<td>.64</td>
</tr>
<tr>
<td>Bell Atlantic (RHC)</td>
<td>.512</td>
<td>.430</td>
<td>.50</td>
<td>.59</td>
</tr>
<tr>
<td>BellSouth (RHC)</td>
<td>.600</td>
<td>.430</td>
<td>1.05</td>
<td>.76</td>
</tr>
<tr>
<td>Centel Corp.</td>
<td>.887</td>
<td>.425</td>
<td>.75</td>
<td>.50</td>
</tr>
<tr>
<td>Cincinnati Bell</td>
<td>.493</td>
<td>.400</td>
<td>.45</td>
<td>.35</td>
</tr>
<tr>
<td>Coastel Corp.</td>
<td>.1174</td>
<td>.440</td>
<td>.80</td>
<td>.46</td>
</tr>
<tr>
<td>GTE Corp.</td>
<td>.256</td>
<td>.350</td>
<td>.90</td>
<td>.46</td>
</tr>
<tr>
<td>NYNEX Corp. (RHC)</td>
<td>.639</td>
<td>.420</td>
<td>.85</td>
<td>.52</td>
</tr>
<tr>
<td>Pacific Telesis (RHC)</td>
<td>.739</td>
<td>.440</td>
<td>.90</td>
<td>.54</td>
</tr>
<tr>
<td>Rochester Tel.</td>
<td>.518</td>
<td>.450</td>
<td>.75</td>
<td>.52</td>
</tr>
<tr>
<td>So. New England Tel.</td>
<td>.653</td>
<td>.425</td>
<td>.70</td>
<td>.53</td>
</tr>
<tr>
<td>Southwestern Bell (RHC)</td>
<td>.802</td>
<td>.400</td>
<td>.85</td>
<td>.57</td>
</tr>
<tr>
<td>United Telecom</td>
<td>.1410</td>
<td>30.0</td>
<td>.95</td>
<td>.48</td>
</tr>
<tr>
<td>US West (RHC)</td>
<td>.667</td>
<td>.420</td>
<td>.80</td>
<td>.58</td>
</tr>
<tr>
<td>Average</td>
<td>.341</td>
<td>41.3%</td>
<td>.80</td>
<td>.54</td>
</tr>
</tbody>
</table>


Note: RHC indicates the utility is one of the seven regional holding companies formed with the breakup of AT&T. The debt-to-equity ratio was calculated as long-term debt plus preferred stock to common equity.
Finally, if the embedded cost of debt funds is, say, 8 percent, we would estimate the regulated division’s weighted average cost of capital in the following fashion:

<table>
<thead>
<tr>
<th>Percentage</th>
<th>Component</th>
<th>Weighted</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>weight</td>
<td>cost</td>
</tr>
<tr>
<td>Debt</td>
<td>45%</td>
<td>8.0%</td>
</tr>
<tr>
<td>Equity</td>
<td>55</td>
<td>12.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Thus, the allowed rate of return, \( r \), as referred to in Eq. (1), would be 10.3 percent.

Of course, as firms in the telecommunications industry continue to diversify into unregulated areas and services, it will become increasingly more difficult to assess the business risk of their regulated activities. One technique would be to identify a small group of publicly traded proxy (pure-play) companies and use their observed levered market betas for the regulated division beta and then apply the CAPM to estimate the division’s cost of common equity capital. In the event that the target debt ratio (or common equity ratio) for the regulated division is not similar to the average debt ratio for the proxy companies, the observed levered beta could be first unlevered and then relevered in accordance with the division’s target capital structure.

An alternative would be to develop a generic cost of common equity capital using proxy regulated firms in some combination from electric utilities, gas distribution companies, and telecommunications firms. This generic cost of capital could be adjusted to reflect possible differences in the regulated division’s target capital structure from the average capital structure mix implied in the generic rate of return. If the CAPM approach is used, the betas could first be unlevered and then relevered. In contrast, the DCF method would require a more subjective adjustment because no formal mathematical link has been established between the constant growth model results and the degree of financial leverage. While the DCF results reflect both business and financial risk, it is difficult to separate out the specific effect of each type on the cost of equity capital.

One further point deserves some discussion. Since it is the total risk (business and financial) that matters, a pure regulated firm with relatively low business risk could take on more financial risk by utilizing a higher debt ratio than could a pure unregulated firm with a relatively higher business risk. Thus, a regulated firm which has been diversifying into riskier unregulated activities might move to a more conservative (higher equity) capital structure in order to maintain a given amount of total (business and financial) risk. A direct estimate of the cost of common equity capital for this firm would reflect both the higher business risk and lower financial risk due to the firm’s unregulated activities.

The overall firm cost of equity capital should be used to estimate the regulated division’s cost of equity only if the unregulated activities are not unusually risky and represent only a small portion of the firm’s total business operations. Otherwise, it may be more appropriate to use the cost of equity capital estimated from either a group of pure-play regulated firms or a derived generic rate of return. This could be accomplished with either DCF or CAPM estimations. Furthermore, if the unregulated activities are unusually risky or comprise a large portion of the firm’s business operations, it may be necessary to substitute a target capital structure in place of the firm’s overall capital structure for purposes of estimating an allowed rate of return, \( r \), for the firm’s regulated activities. This could be accomplished by using an average capital structure for a group of publicly traded pure-play (or nearly so) regulated firms.

**Concluding Comments**

This paper has examined some of the issues involved in attempting to unbundle traditional measures of rate of return by regulated and unregulated services. As regulated firms continue to diversify into unregulated areas, the unbundling issue will undoubtedly increase in importance.

First, by focusing on firms in the telecommunications industry, the traditional discounted cash flow (DCF) and capital asset pricing model (CAPM) methods were reviewed. Second, coverage was given to financial management approaches used to estimate divisional costs of common equity capital. Discussion then followed concerning possible application of these divisional cost approaches to regulated divisions or services of firms comprised of both regulated and unregulated activities. Finally, possible capital structure considerations associated with the unbundling of equity
capital costs by regulated and unregulated activities were examined. Without question, the rate-of-return regulatory process becomes increasingly more difficult as regulated firms diversify into unregulated areas.

Notes

2. In the event that the regulated firm has preferred stock outstanding, the embedded cost of preferred stock dividends is also covered. However, for sake of simplicity, this paper will focus only on debt and common equity funds.
3. Under conditions of exceptional management efficiency or inefficiency, the allowed rate of return might be set above or below the cost of financial capital.


5. For example, over the 1926–1984 period, arithmetic mean annual returns were 3.3 percent on long-term government bonds, 4.6 percent on long-term corporate bonds, and 11.7 percent on common stocks. Standard deviations of annual returns were: 7.4 percent for long-term government bonds, 7.6 percent for long-term corporate bonds, and 21.2 percent for common stocks. As would be expected, the year-to-year volatility (standard deviation) of returns was much greater for the riskier common stock investments.

6. The Federal Energy Regulatory Commission has been actively trying to develop a generic DCF approach for determining rates of return on common equity for electric utilities. For discussion see "Generic Determination of Rate of Return on Common Equity for Electric Utilities," Federal Energy Regulatory Commission, Order No. 420 (May 20, 1985), Order No. 442 (December 20, 1985), and Order No. 442-A (June 11, 1986).

7. For further discussion of the use of analysts' growth forecasts to estimate common stock rates of return, see Harris (1986).

8. One factor that has hindered wider usage of the general risk premium approach is that risk premiums tend to be unstable over time. See, for example, Brigham, Shomo, and Vinson (1985).

9. The CAPM is a single period model, but by using a long-term compound stock market risk premium, we approximate expected returns over the long run. Alternatively, some analysts use the one-year U.S. Treasury bill rate and an arithmetic average one-year stock market risk premium. This latter method, of course, emphasizes short-run conditions.

References

Unbundling Traditional Measures


Comments

Gerald P. Vaughan

I find myself in a very comfortable position. Not too unlike my job at the FCC, as a discussant, I am requested to read and listen to various positions, analyze, weigh, question, and on occasion reach conclusions on those issues. Finally, on rare occasions, I get the opportunity to craft or plant new ideas. We have heard from four distinguished individuals, and I would like to touch upon several aspects in their presentations. My remarks will in no way be conclusionary in a definitive sense, but rather are offered for the purpose of continued thought. As always, my remarks do not necessarily represent the views of the commissioners nor the staff of the FCC.

I think most of you know that the commission contemplates considering a report and order in Docket 86-111 in the next few weeks. Irrespective of what that decision ultimately says, it will not be the final answer to cost allocation. Rather, as with most major policy statements, that decision will be the opening salvo in a long and interactive process. Nevertheless, I believe it will be the blueprint by which future regulation and competition will be
measured. It is paramount to keep in mind that Docket 86-111 is only the third step in a series of efforts under way at the FCC that, in my opinion, will radically reshape regulatory policy, the regulatory process itself, and indeed regulatory law. The unbundling of the measures of rate of return for regulated and unregulated services is not a new concept. As Ronald Melicher indicated, it has been used in varying degrees in other industries as well as in telecommunications. However, with the removal of structural separation, the explosion of technology, and the expansive demand for telecommunications, this issue will become a focal point of increased effort and the rallying cry for heated debate far beyond anything we have seen to date.

The FCC has once again entered the arena of determining the measure or measures of a “proper rate of return.” In Docket 84-800, as in Melicher’s paper, the commission divided telecommunications in two—a “jurisdictional” approach if you will. The commission examined this subject from an interstate versus an all other perspective. Even though Phase III has been completed, staff is gearing up for a Phase II reexamination for the 1985 prescription process. However, as Melicher’s presentation indicated, a great deal of work has to be done and soon. For simplicity’s sake, he assumed various beta’s, target equity ratios, capital and subcapital structures, and so forth. It is, however, these assumptions that are of most concern to regulators. The necessary data and the precise analytical tools to determine their values will be paramount in the years to come if nonregulated services continue to grow and possibly dominate the infrastructure of telecommunications. Unfortunately, too little has been done to develop carefully defined tools or prerequisite testing capabilities. As such, regulators continually call for extensive testimony from experts who disagree—often drastically—and thus leave the decision makers in a void somewhere between the opposing theories. While all the speakers at this session, I think, would agree, nonregulated activities today are small in comparison to regulated operations, this situation will change and change rapidly. Thus, the errors in judgment made today are smaller and easily corrected, but not so small or easy three to ten years from now.

I enjoyed Melicher’s paper from two perspectives. First, I learned a little more on a subject in which I have little expertise. Second, it addresses an issue which is important, is growing, and if not resolved adequately will become a major problem in the future. But we have time, and the real experts here and elsewhere can expand the debate to resolve definitional issues, narrow their differences, and present regulators with an adjusted tailor-made theory and the common data supporting that theory for final acceptance. Without expanded debate, education, and the narrowing of differences, too much will be left to rhetoric and personal ideological opinion.

I can give an example of that. Not too long ago a commissioner was about to hire a regulatory policy expert for his staff, and just before he interviewed the candidates, he wrote four numbers on an easel, 4, 3, 2, and 1, and drew a line. The first candidate happened to be an accountant, and halfway through the interview the commissioner turned to the accountant and said: “Would you please look at the easel and give me the answer.” The accountant looked at the easel, counted on his fingers (accountants cannot add without using their fingers as calculators), walked over, and said “Ten.” The second person who came in happened to be an economist and again, midway through the presentation, was asked to look at the easel and give the answer. The economist studied it for quite a while and then said, “Commissioner, I am sorry, I cannot give you an answer, there is insufficient data. I have to know where we got the numbers, how valid were the assumptions, etc.” Finally, the third candidate, a lawyer, was asked the same question. Without glancing more than a tenth of a second, the attorney looked the commissioner right in the eye and said: “For the kind of money you are paying me, what would you like that answer to be?”

As is true with most conceptual papers, Mark Jamison’s and David Breitz’s paper contained statements I liked, agreed with, questioned, and to be candid—disagreed with. One of the statements I agreed with is that cost studies should be performed on all services, not just nonregulated, or toll, or private line, but on all services. I think this will be a necessary and major requirement in the future, wherever costs, risks, or prices are significantly different or where approved defined subsidies are present. They go on to say that the methodologies used in the cost study should be consistent. I would be more demanding and state that they must be identical in collecting costs for an allocation pool and distributing a specific pool to services. I could not agree more with their
condemnation of the current use of residual ratemaking concepts. In this same vein, their statement that an important property in a costing methodology is that it should be free of cross-subsidization is, in a word, outstanding. Now this may sound strange coming from a member of the FCC that has as part of its rules the Separation’s Manual, which we all know is anything but cross-subsidization free, but the point is, it should be. Moreover, I also agree that it is equally desirable, in some instances, for services to be subsidized. Our job as regulators, however, is to define and identify costs, allocate those costs, and present that result to the social policy makers. They, in turn, decide what services are to be subsidized and how.

The major area I question in this paper is the statement that the stand-alone costing method may well be one of the most important tools available to regulators today. I say “question” because of the hypothetical nature of the study. That is the degree of flexibility inherent in such a study; the historical inability of such studies to pass the test of time; the test of new policy makers; and most important to pass the test of comparison and reconciliation with current facts. Nevertheless, my state colleagues have convinced me that this tool could have value if properly used, and thus I will ask staff to take a closer look at the method and various states’ results for possible use in staff research.

Without belaboring the point, one area in which I strongly disagree with Jamison and Brevitz has to do with their statements regarding costs associated with affiliate transactions, specifically their implied agreement of imputing revenues in the form of a royalty or of affiliate payments for such things as personnel transfers from regulated to nonregulated activities, corporate reputation, or earnings stability. I think this is wrong and a very dangerous road for any regulator to take. First, people are not owned by the company, much less the public. We as regulators are mandated to provide a reasonable opportunity for a company to earn its authorized return—nothing more. The fact that a company did earn this return, did so in an highly efficient manner, and so forth, does not accrue any future, public right or vested value to the public beyond what it has received from the service.

Obviously, all regulators do not agree, but I wonder if equity would dictate the opposite is equally true. Would a regulator allow a company, for ratemaking, to pay x number of dollars to an affiliate for hiring someone away from them or impute an added revenue requirement to a regulated operation which did not have as good a reputation as its nonregulated operations. I think not.

Turning to Gray Collins’s presentation, I find myself, as usual, agreeing with most of what he said. However, just as usual, the parts I disagree with or question were the important subissues.

Collins focuses on the use of nonstructural safeguards, primarily accounting and cost allocation, as a replacement for structural separations. He goes on to state that the costing procedures should be based on cost-causative principles. Up to this point I am in agreement. Yet, I am cautious, for it must be remembered that the commission has looked at cost causation in the past and, in fact, adopted those principles as a requirement—with dismal results. Nevertheless, in Docket 86-111 the commission proposes an untrenched in cost causation. Thus, it is not in the principle that difficulty lies but in the application, definition, and form, which must be crafted carefully. To paraphrase Mark and David, it is in the area of definition and application where regulators must interject judgment in order to minimize imprecision and truly level the playing field. Unfortunately, my reading of the company’s comments in Docket 86-111 generally gives a picture of minimization and flexibility; flexibility in the sense of do not tie their hands or create too many hoops, thereby creating inefficiencies to the ultimate detriment of the ratepayer; minimization in the sense of do not change unless absolutely necessary, do not make the companies create new data sources, mechanisms, and so forth, not already in its systems. In my opinion, this is short sighted and the first step to dismal results. In this case, however, dismal results will not simply mean a change in the pricing of one regulated service versus another but could mean the reinstitution of structural safeguards, a situation universally opposed by the companies and contrary to my commission’s procompetitive goals. Nevertheless, just as cost causation was once adopted, then rejected, and now once again is before us, so can structural separations reappear.

I say this not necessarily as a warning but as an exercise in “skepticism,” for policy and principles do not make things work. If, indeed, as many believe, the industry is on a fast track to major competitive offerings, the accounting and costing tools of today may not be sufficient to respond to regulators’ and legislatures’
questions regarding the public interest.

Collins goes on to support the adoption of a service cost approach, using cost-causative principles, and stresses opposition to the inclusion of "any arbitrary allocations." Bell Atlantic in its filings in Docket 86-111 argues for incremental costing in combination with "above-the-line" accounting treatment for all nonregulated services, thus contributing to overhead as the marketplace permits. Services which could be sold well above incremental cost would make a large contribution, while services which are subject to intense competition might make little or no contribution. Said a hundred ways, it boils down to the statement: Will the FCC prescribe an incremental or fully distributed cost methodology (FDC)?

If there is any doubt about the answer, let me remove that doubt. FDC is the basis of the commission's ratemaking and will continue to be that basis for at least several years to come. That is not to say it is the end, simply the beginning. Judgment, flexibility, and new methods will play major roles in commission deliberations, yet until something better—something proven better—comes along which can answer to the public interest in a monopoly environment, the bottom line is FDC.

Just as I questioned the "benefit test" in judging employee transfers or corporate reputation, I also question seriously the application of cost-causative principles with an opposition to inclusion of arbitrary allocations. Taken to an extreme, an extreme, by the way, I do not believe Collins supports, it would nonetheless create a structure which could change drastically the economics of corporate decision making not only as political and social policies change but also as the perception of services evolves. The inherent flexibility in such an approach is just as dangerous as building in cross-subsidies in a costing mechanism. I am not advocating rigidity nor am I opposed to flexibility, my concern is flexibility, like decision making, must be scaled and rigidly controlled. Technical staff and reporting requirements must not have the same degree of flexibility as decision makers, and thus the ground rules must be defined and drawn precisely. If these rules are not, we may all find ourselves sitting in a commissioner's office answering the question on the easel.

Comments

Lawrence P. Cole

Let me say at the outset that what I miss most from my college teaching days is that freedom of expression we know as "academic freedom." Professors can say the most outrageous things in public without risking much more than embarrassment to themselves. But when one works for a regulated firm, one has to behave much more "responsibly," lest one affect the livelihoods of tens of thousands of employees and the fortunes of equally numerous stockholders. Therefore, my remarks today will be rather restrained.

With respect to Gray Collins's presentation, I naturally share his concerns that the outcome of the FCC's Docket 86-111 proceeding is likely to be a proliferation of cost allocation rules. More Interim Cost Allocation Manuals (ICAMs) are precisely what the industry does not need now, in my opinion.

Recall what the FCC offered in its Notice of Proposed Rulemaking a choice between two methods of cost allocation as a replacement for structural separation requirements. That is the old tactic of asking a customer whether he wants chicken soup with rice or chicken soup with noodles and not giving him the opportunity to order some other kind of soup or a salad instead. Well,
at GTE we definitely do not want soup, especially any kind of
government-approved chicken soup, so we proposed transaction
charges similar in nature to the service costs that Collins dis-
cussed.

What we are dealing with here, of course, are transfer prices for
transactions between the constituent parts of a multiproduct firm,
some of whose entities are regulated and some not. There is an
extensive economics literature on transfer pricing in unregulated
firms and only a small body of work on transfer pricing in the
context of regulation, some of which I have contributed in the
past couple of years, but I know of none which recommends cost
allocation as an appropriate mechanism.

For the record, I should point out that I belong to that school
which regards cost allocation as the microeconomics branch of
voodoo economics. But I am not merely uttering that school's
view in saying that the cost allocation advocates are committing
a logical error when they assert that because total costs have to be
recovered they have to be fully allocated before prices can be set.
After all, what Ramsey prices do is recover the joint and common
costs by "allocating" them ex post, as it were.

From my viewpoint, then, it is simply incredible that the
FCC—after describing the excruciating detail involved in im-
plementing the separations process and acknowledging that the
outcomes produced by the small army of specialists which en-
geage in this cost-inventing exercise are not economic costs in any
cost-causative sense, and after reciting the dismal history of the
ICAM—proposes more of the same for the industry in a period
when it is experiencing growing competitive entry. If this is un-
regulation, then please spare us from complete deregulation.

As I understand what Collins is saying, there is the possibility
that the costs of maintaining structural separations will be less
than the costs of implementing and complying with the anticipated
cost allocation rules, in which case the telcos should opt for
the former. Furthermore, drawing on his example of the allocation
of the costs of vehicles as part of general overheads, for example,
to services for which the vehicles are not used, the prescribed cost
allocations may result in prices for some services that are not sus-
tainable in the market, in which case the telcos will not be able
to offer them. Presumably, that is not an objective of regulation,
but it could be a very real byproduct of it in this docket.

With respect to Ronald Melicher's paper, I must admit to
knowing next to nothing about finance—corporate, public, or per-
sonal. Therefore, I will not have much to say, except that his paper
is in the mainstream of the academic finance literature, and he is not
grinding any axes. It turns out that some of the approaches he
describes are already applied to GTE in some states in which we
operate and, hence, are not a radical departure from current prac-
tice. An informed discussant would probably be able to comment on
the relative difficulties one would expect to encounter in try-
ing to implement the various methods Melicher has demonstrated,
but since I am not, I will not even try.

The paper by Mark Jamison and David Brevitz is recent vin-
tage Melody-Gabel regulatory "economics," which means I cannot
possibly comment on all the things in it with which I dis-
agree. There is the usual reference to "the New York Univer-
sity/Princeton University/Bell Labs think tank," which is a vari-
ation on the old "tune," "The Princeton-Holmdel Axis"; there is
also the usual undocumented assertion that "recent advances in
economic and accounting theory have shown that the allocation of
common costs is important from both economic and equity
perspectives," which is very like an assertion made by William
Melody in his unpersuasive to the judge testimony on behalf of
MCI in its civil antitrust suit against AT&T. But these are rela-
tively minor infractions which just give one a flavor of the paper;
there are more serious concerns, and I want to treat two of them
in some detail.

The first has to do with the basic thrust of the paper, which begins by asking: "Should regulators concern themselves with de-
veloping cost-of-service methods for regulated telephone compa-
nies?" My answer, of course, is no. What regulators should be
doing is requiring companies to do and submit economically com-
potent cost studies; if necessary to get that accomplished, they
should replicate the process utilized in getting the electric util-
ity industry to perfect methods of marginal cost estimation which
were both consistent with economic theory and acceptable to in-
dustry and regulatory analysts. EPRI played a role in this, as did
a number of state commissions. On the basis of what we have
seen so far, cost-of-service rules and manuals for telephone have
been cost allocations thinly disguised to make the prices of certain
services come out the way the regulators or other proponents of
the particular cost-of-service methods want them to. If that is the real bottom line with regulators, then the honest thing to do is to set ceiling prices on those sensitive services and get out of the business of pervasive rate-of-return regulation, which is what the proponents of the Social Contract approach are proposing.

That is not what these authors discuss here, which is not to say they oppose that idea. What they do dwell on is all the incentives and opportunities the telcos allegedly have to mistreat monopoly ratepayers in order to behave anticompetitively in unregulated markets and, hence, all the steps regulators must take to prevent them from doing so. To me, this manifests "the regulatory imperative." In this case it takes the form of micro management of the companies by the regulators to achieve their social agenda; it is not regulation attempting to achieve the outcomes a competitive market would produce if it were viable. The latter is what I understand to be the official rationale for regulation in this economy.

Of particular concern to Brevitz and Jamison are the exchange carriers' investments in new technologies which both lower costs of delivering existing services and provide the capability of offering a wide variety of new services that at least initially will be of use primarily to large business customers. Their concern is that monopoly ratepayers are going to pay more than their "fair share" for this modernization, which is not entirely driven and justifiable by cost reductions that will benefit all users. They are also concerned that revenues from those same monopoly ratepayers will be used to cross-subsidize the competitive activities of the telcos beyond paying for more of the investment costs than should be attributed to the traditional, garden variety voice monopolistic services.

They say, for example, that "in order to discourage competitive entry, provide enhanced services, and position themselves for the information age they believe is to come, Local Exchange Carriers (LECs) are rapidly diversifying services, constructing new and more modern local facilities to convert to wideband networks for the provision of enhanced services, and, concomitantly, more quickly retiring older facilities." This is worrisome to them because it does not accord with their view of the LECs' mission, which is to concentrate almost exclusively on providing POTs to ordinary ratepayers at least cost. In my view this fixation on POTs is a prescription for the railroadization of the LECs, a concern that was on the minds of many state regulators when the divestiture was first announced. We all remember the predictions that the LECs would end up being providers of dial tone and AT&T would get all the action. Thus, Judge Greene gave the LECs Yellow Pages so that the monopoly profits earned in directory publishing would continue to underwrite local rates, and state regulators pronounced it good. Evidently, some diversification is okay.

With respect to the quote about modernization cited above, let me say that if the LECs do not prepare for the information age before the demands for new services materialize unambiguously, there is a good chance some other firms will already be occupying the high ground when state regulators who behave as Brevitz and Jamison want them to decide it is time to let the LECs join the fray.

With respect to the cross-subsidy issue, it seems to me there are two relevant facts to consider. LECs get the vast bulk of their regulated revenue from access charges to interexchange carriers and from basic monthly service charges. If the former are set too high, the IXC's will bypass the LECs and that revenue source will diminish. The latter has not been compensatory for two or three decades. So where are the deep pockets with which to cross-subsidize competitive ventures?

The second area I want to focus on is the analytical cost method recommended in their paper, the stand-alone cost study. In general, I think this is a constructive suggestion, but there are serious flaws in the way the authors think these studies should be conducted. There need not be, because the authors have cited practically all the relevant economics literature on stand-alone costs as tests for subsidy free prices, including the literature containing the generally accepted economic definition of subsidy free prices. Frequently, those advocating the use of cost allocations to prevent cross-subsidy do not cite any such definition, which is convenient for them because they really just want to use cross-subsidy as a hobgoblin anyway. But these authors are not guilty of that bit of demagoguery.

To see the problem in what they recommend, it is necessary to recall what the stand-alone cost test is. As correctly stated by the authors, the prices for a set of services offered by a multiproduct firm are subsidy free if the revenues received for no subset of those
services, including single product subsets, exceed the stand-alone cost of providing them, and if total revenues do not exceed total costs. To understand precisely what this test entails, consider the example of a local exchange carrier which produces three services: network access, local switched usage, and local private lines. For simplicity, I am assuming that the LEC does not provide intralATA toll calling and that one can regard that part of a toll call which goes from the customer’s premise to an interexchange carrier’s POP as a local call. The stand-alone cost test has to be applied to each of the three services individually and to each of the three pairwise combinations of services, that is, the cost of standing alone together. If the LEC produced more than three services, the test would have to be applied to all possible triplets, quadruplets, and so forth. The number of tests gets large in a hurry for a real firm. But that is only the beginning of the difficulties.

Consider just what it means to conduct a stand-alone cost study of an LEC that offered only local network access and private line service. It means estimating the cost of building and operating a hypothetical company to do what probably no telco does, and at specific levels of the two outputs. To do that, one starts by getting engineers to design such a network that has no switching capacity, then gets an estimate of the cost of the plant, equipment, materials, and supplies needed, next an estimate of the cost of installation, and finally an estimate of the various costs of operating. These are the same steps necessary to produce the paper Leonard Waverman wrote in the 1960s about how large an MCI-type competitor of AT&T had to be to enjoy most of the economies of scale inherent in microwave transmission.

As described in the foregoing, stand-alone cost studies are not conducted by going to the books of the existing company, determining which costs can be directly attributed to individual services or sets of services, and allocating the remainder. Rather, they are done by building the firm from scratch, even if for a past period. This is not what was done, evidently, in the so-called stand-alone cost studies cited by the authors as having been performed and entered in evidence in several jurisdictions. Hence, their conclusions are meaningless.

What I think can be salvaged from this proposal is utilization of the fact that an equivalent test for subsidy-free prices is the incremental cost test, which goes as follows: If total revenues do not exceed total costs, and if the revenues received by all subsets of services are at least equal to their incremental costs, then no sets of services are being subsidized by any other sets of services. The incremental cost studies may be easier to do on a going-forward basis, insofar as new services are concerned. That is an empirical matter, and time will tell. What will not tell us anything economically useful is a hybrid that mends stand-alone cost or incremental cost up to a point and cost allocations thereafter.
Part Five

The Role of Regulation in Planning Least-Cost Power Supply
Economic Incentives and Commission Control in Least-Cost Planning by Utilities

Stephen Wiel

The electric utility industry has been regulated almost since its inception. It was born on October 21, 1879, when Thomas A. Edison devised a practical incandescent lamp at his laboratory in Menlo Park, New Jersey. The Pearl Street Electric Power Station, built by Edison in New York City, began operation on September 4, 1882. In 1907, Georgia, New York, and Wisconsin established regulatory commissions with jurisdiction over public utilities, including electric companies, and other states soon followed. From that first state regulation until prices began to rise in 1970, state commissioners presided over decisions of how customers should share the benefits of lower prices. That changed in the 1970s.

The first response to the rising prices of the 1970s was a flood of rate cases filed by the electric utilities with their commissions. These were panned, one on top of another, as companies filed for new rates before a decision had even been rendered on a previous request. Then fuel adjustment clauses were instituted to protect
the utility company from rapidly changing fuel costs. By the end of 1974, almost all state commissions had approved a fuel adjustment clause. Some states changed their ratemaking laws to base rates on projected future test years instead of the previously universal historic test years. Some states allowed companies to start recovering new plant construction costs before the facilities plants became operable.

Some states, including North Carolina and California, began to get involved with the utilities’ planning by developing independent forecasts for demand growth. Some states, California and Wisconsin, for example, mandated conservation and load management by the utilities in an effort to increase electric efficiency and avoid the use of expensive fuel and the construction of new plants. This regulatory activity has left utility companies across the United States with an array of incentives and disincentives for investing in conservation and load management.

Utility companies and regulators are still searching for a comfortable balance among economics, risk, and social equity as they preside over the evolution of their regulations and practices. The tug-of-war among these three factors can be readily seen in a single enlightening example.

Reno Lightbulb Sheds Light on Social Issues

Let us look at the effect of screwing in a light bulb in Sierra Pacific Power Company’s service territory. Sierra Pacific (which services Reno, Nevada, and most of the surrounding area) was chosen only for convenience: the issues are the same throughout the country. Furthermore, let us compare the effect of screwing in a standard 60-watt bulb with that of a 15-watt Mitsubishi Marathon bulb that is designed to provide equivalent light.

Figures 1 and 2 compare costs of continued use of the two bulbs from a customer’s and from a utility company’s point of view. The comparison assumes an average residential use of about four hours per day. When the purchase cost of each light bulb is compared, the 15-watt Marathon bulb costs $1.35 per year to keep in place, assuming no installation costs, but it saves 45 watt-hours every hour it is on; at Sierra Pacific’s kilowatt-hour of 8.5 cents rate, it saves $5.38 per year.

When a utility executive sees a standard bulb replaced with a Marathon bulb, he is likely to say: “Oh my god, there goes

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<td>LIFE OF A 15 WATT “MARATHON” BULB:</td>
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<td>RETAIL PRICE OF A 15 WATT “MARATHON” BULB:</td>
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<td>ANNUAL COST OF A 15 WATT “MARATHON” BULB:</td>
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<td>OPERATION COST</td>
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<td>ANNUAL ENERGY CONSUMPTION OF A 15 WATT “MARATHON” BULB:</td>
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<td>ANNUAL OPERATION COST OF A 15 WATT “MARATHON” BULB:</td>
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<td>OPERATING CUSTOMER SAVINGS (UTILITY REVENUE LOSS):</td>
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| LEFT SAVINGS TO CONSUME (PER PEAK UTILITY REVENUE LOSS): | ($3.39) /YEAR |

Figure 1. Sierra Pacific Power Company, Comparative Cost Analysis of a 60-watt Inconceadent Bulb and a 15-watt High Efficiency “Marathon” Lamp.
my revenue. In fact, there does go some of his revenue. There also goes some of his cost. As shown in Figure 1, he loses $5.38 in revenue per year. Figure 2 reveals that the utility only gets rid of $2.56 per year of its costs, about three-quarters ($1.92) of which is fuel not used and one-quarter ($0.64) avoided power plant construction.

All these cost effects are summarized in Figure 3. The customer pays an extra $1.35 to the light bulb store each year but $5.38 less to the utility company. The latter pays $2.56 less per year to the fuel company and to construction companies. It is not responsible, however, for the difference between its $5.38 reduction in revenue and its $2.56 reduction in cost. That $2.82 shortfall in contribution to the company's fixed overhead and profit must be provided by its 100,000 other customers. In the long run, the utility company is somewhat neutral to this process.

Is the effect of the switch to the Marathon bulb good or bad? That depends on one's perspective.

**Perspectives**

- **Nominal Effect**
  - $4.03 per year saving
  - $0.000028 per year cost
  - Long term: neutral
  - Short term: neutral or $2.82 loss, depending on state regulation
  - $2.56 per year savings
  - $2.11 per year lost revenue
  - Indeterminate (depends on extraction and production costs of utility fuel, power plants, and light bulbs)

The utility's point of view is of prime interest here. Is it motivated to encourage customers to screw in a Marathon bulb instead of a standard bulb? Does it benefit them to pay customers to do so? Is it in regulators' interests to make it happen? There are no pat answers to these questions.

From a regulatory commission point of view, the utility and its customers, as a whole, are saving a net $1.21 per year if the Marathon bulb is used. That is good—so long as concerns about risk and equity are also satisfied. Clearly, the utility company...
should promote the more efficient bulbs but should not spend more than $1.21 per year per bulb on its program to get Marathon bulbs installed. First and foremost, the effort should be made only if it is the utility's most cost-effective option, providing the most efficient production and use of energy.

Some people claim that the Marathon bulbs should not be promoted so long as any one customer will have to pay more, even if only $0.000023 per year. They would reject a program to promote Marathon bulbs based on the economics described above, claiming it failed the equity test. Others would make the argument that the light bulb promotion should only be rejected for these reasons if there are not enough new customers to contribute more than the $2.82 shortfall. They argue that if there are enough, rates will not go up, and no one will have to pay more. I prefer to judge equity as the Nevada Commission instructed Sierra Pacific to do in a 1986 Opinion and Order.

Furthermore, the Commission disapproves of Sierra Pacific's Nonparticipant test as applied in this plan. Sierra Pacific used this test to eliminate from consideration potentially cost-effective demand-side measures (see Exhibit 5, table 6-3). Even worse, Sierra Pacific used the test to eliminate existing programs without commenting on its rationale and ignoring the fact that it had collected two years worth of data during the trial program (Exhibit 5 pp. 10-130 and 10-131). The Commission agrees with the OCA that the use of this test to eliminate demand-side measures in this way must stop. However, the Commission does not agree to abolish the Nonparticipant test. NAC 704.934(2)(e) requires the utility to take into account equitable considerations such as requiring one subgroup of ratepayers to subsidize another group. It is appropriate for Sierra Pacific to consider the nonparticipant. Sierra Pacific should use the Nonparticipant test in resource planning to evaluate the distribution equity of the entire package of demand-side measures. In the future, Sierra Pacific could recommend an adjusted mix of demand-side measures in order to redistribute the benefits from the selected package of demand-side measures more equitably, but Sierra Pacific should always present for reference the least-cost package which has failed the Nonparticipant test and which it no longer recommends.

We saw above that utility executives have no direct long-term financial interest in the choice of a light bulb. In a few jurisdictions they have no financial interest in the short run, either; that is not true in Nevada. Sierra Pacific Power Company participates in an historic test year ratemaking process, and consequently it is going to lose $2.82 per year until its next rate case. At that time rates will be adjusted so that any effect from the light bulb that is reflected in the test year will be included in the new rates. If the company times its rate case properly, it will once again annually recover the entire $2.82, but in the short run it is losing $2.82 per year. In our neighbor state of California that would not be true, since an annual revenue adjustment mechanism ensures that utilities recover their fixed costs exactly, no more and no less.

In Nevada, the utilities were concerned over the risk of recovering their resource planning expenses, a risk minimized by allowing
them to recover their planning costs through a balancing account. Later, the utilities decided they needed pilot projects to test, for example, how the market would react to a rebate for light bulbs or to other inducements to switch bulbs. The utilities were concerned about whether they would recover these costs, and it was agreed to include pilot project costs in the balancing account recovery.

Now the utility companies say they are worried about how the commission would treat investment in light bulbs in their next rate case. The commission has not provided special rate treatment for what it calls "full implementation" because it wants to avoid biasing the selection among demand-side and supply-side measures. Full implementation is defined to occur after the utility has the measure "on the shelf," when it is reasonably sure of the level of savings it will achieve. That is simply considered an investment. At present, the utility not only lacks direct financial incentive to make such an investment but also feels it would be taking a financial risk. The uncertainty, not the basic economics, is causing caution and reluctance to invest. Should half a billion dollars spent promoting light bulbs be considered an expense in a rate case, or should the company put it into its ratebase and recover it over the life of the bulbs or some other period? We have not answered that question yet, but some states have.

Survey of Controls and Incentives

We in Nevada conducted a survey of all states to see (1) how they treat the recovery of investments in light bulbs and (2) what controls they have over investments. Table 1 shows how the commission in each state that responded to the survey treats investments by utility companies in conservation and load management. For example, Nevada has balancing account treatment, as I mentioned, for its planning and pilot projects and not for its implementation of conservation and load management programs. Some states offer a balancing account for full program investment, others offer rate basing or normal expensing, and still others offer a rate-of-return incentive. Table 1 indicates the variety of approaches among the states.

Table 2 lists where the same states have power to review and presumably stop an investment in a power plant. One-third of the states responding now require preapproval of a long-range plan. Some states have site permitting and others have construction permitting as the commission's first opportunity to assess need. The latter the first assessment, the more difficult is the commission's decision. In my opinion, conducting a prudence test during a rate case after a power plant is built is too late in the process to decide whether the plant should have been built. Everyone is penalized, and we have not found the new efficiency for which we are looking.

There is no one right answer for all states. Despite the variety of regulation, many utility companies across the nation are finding the best recipe for their investments. I personally prefer long-range planning with commission preapproval. If, in the process, commissions share the responsibility to some degree, I think that is okay. In that sharing and that review, society finds a more efficient way to generate, transmit, and distribute electricity.

Notes

2. In fact, there are several noneconomic differences between the bulbs which will undoubtedly influence the customer's choice.
3. Each of Sierra Pacific's 100,000 customers would pay $2.82/100,000 per year. Granted, the customer who switched to the Marathon bulb would pay his own share, but that is negligible compared to his $5.38 per year lower utility bill.
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**NOTES TO TABLE 1**

(1) **TERM:** CAPITALIZED AT THE END OF THE RATES CASE IN WHICH THE LWP MANAGEMENT PROGRAM WAS PROPOSED.
(2) **PREVIOUS:** NO DATA WERE AVAILABLE OR AUTHORIZED FOR INVESTMENT IN LWP MANAGEMENT PROGRAMS.
(3) **EXCHG:** PLANNED AS SPENDING TO BE MADE IN A MORTGAGE RATES RATES CASE OF INVESTMENT IN LWP MANAGEMENT PROGRAMS.
(4) **ENERGY:** NO FORMAL DETERMINATION OF FUEL COSTS INCREASES TO INVESTMENT IN LWP MANAGEMENT PROGRAMS.
(5) **MATERIALS:** NO FORMAL DETERMINATION OF FUEL COSTS INCREASES TO INVESTMENT IN LWP MANAGEMENT PROGRAMS.
(6) **LABOR:** NO FORMAL DETERMINATION OF FUEL COSTS INCREASES TO INVESTMENT IN LWP MANAGEMENT PROGRAMS.
(7) **OTHERS:** NO FORMAL DETERMINATION OF FUEL COSTS INCREASES TO INVESTMENT IN LWP MANAGEMENT PROGRAMS.

**P.I.D.:** MEANS FUTURE TEST YEAR
**E.I.:** MEANS EXPECTED TEST YEAR
**R.P.O.D.:** MEANS BACK TO BUDGET
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<th>Table 1: Comparison of Various Incentives in Power Plants</th>
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Note: Table 1 shows a comparison of various incentives in power plants across different states. The table includes columns for pre-approval, state, and carbon incentives. Each state is listed with its respective incentives for pre-approval and carbon incentives.
Regulatory Monitoring of Electric Capacity Planning: An Assessment of Wisconsin's Experience

Mary Lou Mants

January 1, 1987; Anita Sprenger, Director, Office of Conservation and Energy Efficiency; and Terry Nicolai, Bureau Director of Electricity Rates, for their dedication to the success of our planning process and for their helpful comments.

History and Legal Framework

The power plant siting law passed in 1975 was a major achievement during the administration of Governor Patrick J. Lucey, an activist governor in the tradition of the LaFollettes. He had appointed new blood to the Public Service Commission, which led to the landmark Madison Gas and Electric rate design case in 1974. In this case, the commission adopted marginal cost pricing as the appropriate benchmark for the design of electricity pricing and decided to phase in flat rate and peak-load pricing structures instead of the traditional declining-block rate structure. These policies were intended to provide a fairer apportionment of cost than the traditional embedded cost approaches and to promote a more efficient allocation of resources through rate design which encouraged conservation and load management. This decision reflected the commission’s growing concern about the cost consequence of the utilities’ need to double their capacity every ten years.

At the same time, a more environmentally aware legislature passed Wisconsin’s Environmental Policy Act in 1971, the Wisconsin version of NEPA, and was drawn into a variety of environmental issues. The controversy over proposed nuclear plants was spilling into the legislature. For example, as a result of public outcry, legislative committees held hearing in 1973 on a proposed nuclear plant. The scene soon shifted to the struggle over the power plant siting legislation.

The stage had been set for the legislation by Governor Lucey’s first budget, in 1971, in which the sharing of utility taxes with local communities was drastically reduced. With loss of the tax inducement for communities to accept a power plant, the utilities were in dire need of an override of local zoning if they were to site the seven nuclear plants on their agenda. At the same time, environmentalists were looking for ways to stop the nuclear plants and wanted the commission to have a planning process which would look critically at load forecasts and at alternatives to the nuclear plants, such as conservation.
The first version of the bill failed in 1974 over the issues of whether the advance plan should be a contested case process and whether there should be an environmental impact statement. The bill passed in 1975 after a compromise was reached: The utilities accepted a modified contested case, and the environmentalists settled for an environmental assessment rather than an environmental impact statement.

The strong statutory framework of the Power Plant Siting Act has provided the flexibility to meet evolving circumstances, beginning with the initial issue of the proposed nuclear plants to the present focus on integrated least-cost planning. Our law established a demand forecast period of 20 years; generation plans are developed for 15 years, while transmission plans are only ten years forward. However, the commission recently determined that a 15-year study is appropriate for transmission. Under any circumstances, to compare alternatives fairly, an adequate representation of the full life-cycle cost and effect must be developed for each option.

The breadth of the law is significant and will stand us in good stead if generation or transmission capacity is proposed by someone other than a traditional utility. The statute’s planning requirements apply to “any person” who owns, operates, or plans to own or operate in the next decade a generator of 12 or more megawatts capacity or a transmission line of over 100,000 volts and one mile in length. The authority granted by law is critical to effective joint planning of the utilities in the western part of the state, where the major generation and transmission cooperative is located, since electric cooperatives are not otherwise regulated by the commission. Any entity, including nonutility entities, must receive a certificate of public convenience and necessity prior to construction of such a facility. These criteria have worked reasonably well, although transmission planning inherently requires consideration of 69 kV and lower voltage systems for full benefit.

Our statute permits utilities to file joint plans, and from the beginning our utilities have formed into eastern and western groups to do so. Improvement of the coordination within and between planning groups has been an ongoing effort of the commission over the last ten years. We find the most troublesome issues to be the interface between utilities. Currently, these problems are becoming more aggravated by increasing competition between utilities for wholesale municipal utility customers.

The most important power given to the commission was the ability to approve, reject, or modify plans based on a broad set of factors (engineering, economic, safety, reliability, efficiency, and environmental factors and consideration of alternate methods of generation or sources of supply). The power to modify is the most important tool to shape future utility plans.

An “advance plan” submission is required from the utilities every two years which contains their long-range forecast and plans for future generation and transmission and alternative plans that have been considered. By now, four advance plans have gone through the time-consuming review and hearing process. Each has had its own character and accomplishments. It appears in retrospect that the commission considered more than one or two major issues which have lasting effect.

**Advance Plan 1**

Advance Plan 1, filed in 1976, was a major battleground on the issues of long-range forecasting and coal versus nuclear generation. The utilities were planning to construct seven new nuclear units totaling 6,500 megawatts of capacity in the state, including three units for which there were active applications before the commission. (Note that our total generating capacity then was about 8,800 megawatts and is now about 10,800 megawatts, with adequate capacity until the late 1990s.) The commission determined in its August 1978 order that nuclear power “is likely to be more costly than coal (in terms of total fixed, fuel, and operating costs) when considering present uncertainties in fuel, decommissioning and waste disposal costs” and directed the utilities to cease planning on the basis of nuclear power. This is the only instance to my knowledge in which an administrative body functionally stopped new nuclear plants without specific legislation. The commission specifically allowed planning for two units to continue since they were already applied for and had substantial sunk costs associated with them. The commission finding on forecasting, however, required further submissions related to the need for one of the plants, and both plants were abandoned within the next two years. One plant was denied on the basis of need. For the other, the post-Three Mile Island handwriting was on the wall.
and the utility agreed to withdraw the application in exchange for current return on the unamortized balance of the write-off.

The commission heard much testimony on the forecasts for electric demand and on forecasting methods. It declined to select one, preferring instead a variety of methods to compare and contrast. Trend-fitting, statistical, econometric, and end-use modeling approaches were part of the discussion. Nineteen separate forecasts (at least two for each utility involved) were submitted in the proceeding, and the commission adopted a range of between 3.2-3.9 percent average annual growth rate for the eastern Wisconsin utilities and of 3-4 percent for western Wisconsin. These were to drop in half by 1986 in Advance Plan 4.) To deal with the uncertainties of the demand forecasts, the commission required that the utilities develop alternative plans showing what they would do if the forecasts were either too high or too low. This set the direction for the concept of building flexibility and robustness into system design and selected options.

Transmission planning was only in its infancy in this initial planning process (1976-1978). In the first plan order (1978), the utilities were directed to file an analysis of coordinated planning between the eastern and western utility filing groups for future generation additions. The utilities also received general instructions to proceed with implementation of feasible load management strategies as soon as possible, to promote the use of alternative energy sources by the consumer, to investigate and adopt reasonable alternative utility generation strategies, and to develop incentive rates for cogeneration. It is interesting to look back at these general policy directions, because little came of them in the short run. This led the commission to conclude that more specific orders with milestones are necessary for results.

**Advance Plan 2**

Advance Plan 2 was decided in December 1980. Having resolved the coal versus nuclear issue, attention turned to several supply and demand issues. The utilities argued for large central coal-fired generation (500 mW range), while some commission staff and intervenors advocated smaller dispersed generation strategies, based on reliability analysis. These included small coal units (less than 200 mW) equipped to burn refuse and located in communities where they could provide district heating and/or process steam. A detailed analysis of cogeneration and district heating potential was performed as well as an analysis of using wind generation to reduce load. No specific choice was made on the large central versus smaller dispersed generation issue. The commission did require, however, that any future application for a conventional generating facility must contain evidence showing cause why the need could not be met by generation based on alternative, nondepletable sources of energy, or technologically improved or advanced methods of generation using coal. The utilities were also directed to pursue, and implement where feasible, alternative sources of energy. They were specifically required to commence pilot programs for wind generation and to perform and submit studies on hydroelectric generation feasibility in Wisconsin for the next advance plan.

The forecast issues continued to be controversial. Conservation, rate design effects, and natural gas availability were all explicit adjustments to all forecasts and were not necessarily consistent with assumptions in the base forecast. The commission ultimately approved a growth rate range of 2.4-3.2 percent annually for the eastern utilities and 2-4 percent for the western Wisconsin utilities, down from Advance Plan 1, as each successive plan has continued to be.

**Advance Plan 3**

In Advance Plan 3, issued in May 1983, the central issue was the alternate electric power supply study done by commission staff. This analyzed conservation and renewable resources as a means of supplying new needs for electricity instead of using conventional supply.

The utilities argued that all cost-effective conservation was already in their forecasts and that no more could be relied upon in lieu of planning for additional conventional capacity. They argued that data were inadequate to prove the existence of more conservation potential and that the cost of programs to achieve the potential was not known. The commission ultimately determined that the conservation/renewable technologies existed and were cost-effective compared to conventional generation technologies, although it was acknowledged that program costs required to induce cost-effective conservation/renewable technology measures could not be predicted given the sparsity of appropriate program
data. The Advance Plan 3 order gave the utilities the goal of not building additional conventional generation until after the year 2000 and directed them to develop a parallel plan which did not rely on conventional generation.

In some ways the results of this requirement in the Advance Plan 3 order were disappointing because the utilities did not, in fact, submit parallel plans and developed very few specific proposals for additional conservation. However, the parallel plan concept gradually gave way to utility-commission agreement on integrated least-cost planning as the desired mode during the review of Advance Plan 4.

The order in Advance Plan 3 also required the utilities to implement a number of programs deemed so obviously cost effective as to warrant their immediate implementation. These "baby steps" included a program to supply appliance energy efficiency rating information to customers, a plan for expanding conservation programs for commercial and industrial customers, and a plan for making water heater blankets and flow restrictors available to all customers with electric water heaters. Within our staff there was disagreement as to how far the commission should go in the advance plan context in ordering that specific conservation programs or measures be undertaken.

This was the first advance plan in which conservation was evaluated as an integral part of the forecast rather than being treated as an adjustment to it. Commission staff developed the method and produced demand scenarios built up from end-use data. The commission order required that utilities develop standardized end-use sectors and file end-use sector forecasts in subsequent advance plans, recognizing the need for end-use methods to evaluate conservation options properly.

Virtually no action had occurred on direct load control except by one utility in response to the previous two advance plan orders. The commission determined that some quantitative enforceable standard needed to be established to ensure that load management would be implemented prior to the application for the next power plant. The commission, therefore, required that prior to applying for a new fossil-fueled power plant, at least 30 percent of the electric water heaters served by the participating utilities must be subject to direct load control. Before the commission would grant such an application, at least 50 percent of the electric water heaters would have to be so controlled. In addition, the commission required utilities to submit an analysis of the benefits and costs of accelerating the installation of direct load control ahead of the schedule required for generation capacity deferral.

The other significant issue pertained to transmission system analysis. The commission ordered that, prior to accepting an application for a high voltage transmission line, an analysis of system alternatives must be completed which investigated the feasibility of alleviating or deferring system problems. Among possible options suggested were increasing capacity on existing lines by reconductoring or rebuilding, modifying or replacing limited terminal equipment, installation of capacitors, operator actions, and load management, among other options. The commission also specified a series of additional filing requirements to provide the information necessary to decide on transmission options. It rejected the western Wisconsin utilities' transmission plans on the basis that the record contained insufficient documentation and an inadequate analysis of alternatives. Instead, it ordered a transmission study with the participation of utilities, commission staff, and interested intervenor groups.

In June 1985 the commission issued a supplemental order in the third advance plan docket based on the commission-ordered study. The order was significant in that it established a procedure for transmission system planning which required the use of sophisticated documented analysis to identify problems and alternate solutions on the transmission system. Transmission improvements are to be made to achieve the objective of lowest cost reliable service, including reducing energy losses, reducing voltage, providing for power interchanges, and eliminating system constraints to economic dispatch, among other goals. The study ended in a two-day hearing in stark contrast to the previous 50 days taken to select one proposed transmission line in the Western Wisconsin Transmission System.

**Advance Plan 4**

Advance Plan 4, the only decision in which I have personally participated, was decided in August 1986. It established integrated least-cost planning as the process to be used for Advance Plan 5, a consensus of the commission, utilities, and intervenors. Least-cost integrated planning is an extension of the direction of the
three earlier plans toward nonconventional alternatives and requires that all options be evaluated and compared in a systematic and comprehensive framework. Utilities historically have had the objective of least-cost planning for lowest cost supply; the new direction is to expand the scope of planning to include both demand and supply alternatives, to evaluate options with a broad set of quantifiable and nonquantifiable costs and benefits, and to integrate the two. The order also recognized the existence of enough conservation that would be cost effective in any least-cost plan that it required at least a doubling of utility conservation efforts.

The order is peppered with milestones for least-cost planning, for conservation, for developing a leveled cogeneration contract in which higher payments in the early years are offset by lower payments in later years, for transmission system evaluation and planning, for a policy statement on refuse derived fuel, and many more.

It is striking to look back at the evolution from Advance Plan 1 to Advance Plan 4. The first was truly the war over the nuclear issue and long-range forecasts, with 78 days of hearings and 13,000 pages of testimony. Advance Plan 2 was a more diffuse series of strong controversies, including growth forecasts, with a 10,000-page record and 70 days of hearings. By Advance Plan 3, the growth controversy was over and the commission no longer had the option of focusing on the potential of alternative energy. There was a strong disagreement between staff and the utilities, but the disposal of many earlier issues led to a simpler case. Also, the use of technical conferences helped reduce the length of the hearing to 26 days, with a 1,400-page record.

Advance Plan 4 had a somewhat longer record of 3,997 pages, but much greater controversy among the utilities, commission staff, and intervenors was apparent. There was no substantial disagreement in the record about long-range forecasts, least-cost planning, or conservation. Only transmission remained a controversial area for the eastern Wisconsin utilities.

It took the commission by surprise, therefore, that all the major utilities except one asked for a rehearing of the order on the ground that half of the sixty-four reporting and monitoring provisions of the order exceeded our authority and interfered with management's prerogatives. We reaffirmed our order in all but four provisions, as we are confident that our broad ability to modify plans gives us adequate authority. Our highest level staff also met several times with their utility counterparts to clarify what was meant by the order and how the monitoring process would in fact work.

Ultimately, the utilities did not appeal our order to court. They are adjusting, albeit uneasily, to the fact that least-cost planning requires more continuous involvement of commission staff in utility affairs than does capacity planning. The commission role is to keep the utilities moving toward least-cost planning while remaining sensitive to the need for flexibility in the way we administer the monitoring process.

Sharing of Risk

Our argument to the utilities obviously is that they must take the bitter with the sweet: Along with a commission's ability to guide and monitor utility plans comes a major sharing of responsibility. For us this began in 1931, when the commission was given power to approve major construction projects. With the additional powers granted in 1975, an even greater responsibility is shared. Commission authority to modify plans makes our commission even more responsible for the adequacy of utility activities to serve need. The commission's role is that of being a "Monday morning quarterback," second-guessing unsuccessful calls.

In our process, the utilities know that any prudence review will be limited in scope to specific issues of management of the construction project and will not examine the entire project. This limits the financial riskiness of the utility vis-a-vis utilities located in states that reserve all judgment until the project is completed to determining the stockholders "at risk" for the entire cost of a multibillion-dollar project. During a period of heavy construction, it should provide a powerful positive incentive to the utility to participate in our advance planning process.

Commission involvement in advance planning also allows the commission to approve other risk-reducing financial treatments that otherwise might be too controversial to allow the ratepayer to share in the risk, such as expensing precertification expenditures for planning and regulatory review. For major new construction, such expenditures soon grow so large that they become a proverbial "gun at the head" of the commission—a powerful disincentive
to taking the necessary time to do thorough economic and environmental reviews of construction projects.

Once advance planning was securely under way, the commission found it could deal with this problem by allowing the utilities to expense such planning expenditures. Under Wisconsin statutes, construction cannot commence without a certificate, so expenditures for actual construction cannot be incurred before the commission has fully reviewed and approved the proposal. Because the commission had approved continued planning for a particular plant owned by several utilities, it allowed the expenses of planning and seeking regulatory approval to be recovered currently. This had a favorable financial effect on the utilities by increasing their cash flow and reducing CWIP, AFUDC, and the overall cost of the plant. The ratepayer received some benefit from the lower overall construction cost should the plant be built and from the lower cost of capital as a result of the reduced risk. While the commission did not necessarily find that the ratepayer benefit was equivalent, dollar for dollar, to the resultant increase in current rates, the commission did find that the expenses themselves were reasonable because the commission had already found that the planning for the proposed construction was reasonable. Even if there were no current benefits to ratepayers from this treatment, the commission, knowing that the expenses were reasonable, could allow current recovery as a matter of intergenerational equity. It should be noted that this treatment may cause problems when related to construction that is not included in the planning process, such as minor plant refurbishment.

An even more significant risk-reduction decision that relied in part on the advance planning process was the decision to allow a current return on CWIP for a plant under construction which has received commission authorization by certificate or rule. This allowed a significant portion of the carrying costs of capital invested in plant under construction to be recovered currently from ratepayers, rather than being "capitalized" as interest during construction (IDC) to be recovered during the life of the plant.

Although the commission had, from the early 1970s on, permitted some level of current return on CWIP as a financial matter, the decision to do so soon became as controversial in Wisconsin as it has been in other states. It became a key issue with nuclear opponents, who saw the treatment as just another way of foster-.ing the construction of large new nuclear plants, as well as with consumer advocates, who opposed it solely because it increased current rates.

When the commission finally conducted a generic proceeding in 1979-1980, it found that, having participated fully and knowledgeably in the utilities' planning and decision to construct new plant, it was reasonable to reduce the utilities' riskiness by minimizing capitalized IDC and, at the same time, improving the utilities' cash flow for construction. These decisions were made easier by the commission's participation in the planning and construction decision. (By this time capitalized IDC was becoming such a high percentage of some utilities' income statement earnings that it was rapidly becoming highly suspect by the financial community.) The ratepayers, having determined through advance planning and certification review that plant construction was prudent, could adopt this financial risk-minimization treatment to reduce the overall cost of capital.

Keeping in mind the inherent disincentives for the utilities to participate in least-cost planning, one cannot overemphasize the importance of providing incentives to the utilities for honest and enthusiastic participation. These two early decisions were especially clear demonstrations to the utilities that there were rewards to be gained from the advance planning process other than the mere certification of all desired construction projects. Of course, the real rewards came later, after all the large nuclear projects were either cancelled (voluntarily, but with commission encouragement) or, in one case, actually denied, and the Wisconsin utilities found themselves in enviable strong financial condition at a time their less fortunate brethren were burdened by costly nuclear albatrosses.

These past successes from advance planning will not, in my opinion, be sufficient to enlist the utilities' whole-hearted support for the next round of least-cost planning, particularly in light of continued economic disincentives and the increased intrusiveness of commission oversight, as more and more of the utilities' activities come under scrutiny as part of the review. It is critically important for regulators embarking on the road of least-cost planning to keep an eye out for opportunities to provide utilities and their managers with positive incentives for participation in the process, rather than rely solely on adversarial proceedings and
prescriptive orders.

Some commissions view with horror our relinquishing of the right to find a utility decision to construct imprudent. We, in contrast, believe that our staff and commission resources are more effectively used in the initial planning and approval process than in hindsight prudence review.

Mistakes cost money (in addition to their environmental and human resource cost), and the ratepayers end up paying for them. Even though the planning and facility approval process limits the commission's options when inclusion in the ratebase is being considered, that approval process also reduces the chance of making mistakes and the net cost to ratepayers.

The benefits of our evolving least-cost planning process have far outweighed its costs, and our financially healthy and stable electric utilities which provide low-cost reliable service are evidence of that.

Capacity Planning and Uncertainty

I have touched on some of the successes as well as some of the limitations of our process. It is worth pointing out that even though the technical sophistication of the advance plan orders has evolved greatly, today's decision makers are facing just as great uncertainty as decision makers in the past. In the first advance plan, the commission did not know with certainty that nuclear power would be vastly more expensive than coal. There could at most be uncertainties about economics, a question whether high expectations for nuclear power would really materialize, and whether there was a basic change taking place which would cause future demand to be much less than recent historic demand growth. Armed with our hindsight, the difficult and courageous decisions made in Wisconsin in the late 1970s look obvious. Today's arguments over the uncertainties of future conservation benefits have a very familiar ring.

That said, have there been major failures of our process? The most serious question is: If planning works, why does Wisconsin have excess capacity? Here, again, it is easy to say we have twenty-twenty hindsight, and so it is with some temerity that I suggest some reasons, since I did not participate in the process.

Four coal-fired units totalling 1,860 MW plus 227 MW combustion turbines have been authorized and built since the Power

Plant Siting Act was passed in 1975. Based on 1986 figures, an adequate capacity reserve would exist if only roughly 900-1,000 MW of capacity had been constructed. However, had the capacity planned by the utilities in the first advance plan been built, there would be an additional 5,700 MW of excess capacity.

It is, of course, impossible to know how much scaling down of building plans would have occurred absent our planning process. However, observation of what happened in other states with no planning process makes me thankful that our advance plans brought decision making by the commission and our utilities into quicker and sharper focus with great savings for Wisconsin ratepayers.

Ironically, it appears that the excess coal capacity is attributable both to lack of planning and to lack of belief in planning judgments that deviated significantly from historical norms. Planning for all of these units was completed before an advance planning process was in place. Each of the units was looked at on a case-by-case basis, and the debate centered around uncertainty of need. In each instance there was adequate evidence in the record presented by staff and intervenors to deny or defer the plant, while the utilities were arguing that lower growth was an aberration rather than a structural change in the market for energy.

The commission determined that the growth rate would probably be higher than it turned out to be. The commission decided to hedge its bets by using the shortest lead time plant available short of burning oil in combustion turbines. This was during a period of natural gas shortage, rapidly increasing oil prices, and the potential for large-scale conversions of oil-based end-uses to electricity (for example, space heating, transportation). Building coal plants was generally the cheapest way to serve those potential needs.

The one plant considered in the advance plan process was even more peculiar in that the commission by that time recognized that it was not needed for capacity purposes. An evaluation of the costs showed there was an economic rationale for constructing the plant while it was still grandfathered under the Clean Air Act, because building it and blending coal at another baseload unit on site provided cleaner air than the expensive scrubbers that would have been required by waiting.

The transition to the new planning process was taking place
during the beginning of the heavy building plans of Wisconsin utilities, and the focus of environmental intervenors and public attention in the beginning of this transition was on the proposed nuclear capacity. Coal capacity received less attention, and strong pressure was on the commission from the utilities and industry groups to move quickly to prevent brownouts. Weighed in hindsight, the wise decisions of the commission of that period on nuclear capacity resulted in economic benefits which far exceed the cost of excess capacity due to the commission's cautious decisions to build too many coal-fired plants.

However, the interplay in this early period between the advance plan process and the construction cases actually built the foundation for essential linkages of planning and construction and developed the staff expertise which has stood us in such good stead. There was an ongoing juggling between the advance plan proceedings and the construction application cases for plants that had been planned before the law had been adopted and the integrated planning review was commenced. Nonetheless, these individual construction cases contributed to the advance planning process. Issues raised in them were transferred to the advance plan cases, in particular coal versus nuclear and large plant versus small. The original move toward load management was made in a construction case, where the commission made the utility develop 100 mW of load control as a condition of construction of one of the coal-fired plants discussed above. In this instance the controversy was whether emergency construction was required, or whether 100 mW of load control could be achieved within the period required for construction as proposed by staff. The commission, conservatively, allowed the emergency construction but added a condition that the company also develop 100 mW of load control within the period.

The success the commission had in handling the confused situation of the transition period is largely due to the fact that there was strong continuity at the staff level and that the same staff dealt with both the construction cases and the advance planning. Not only were they able to understand the interrelations between the two processes, but also they could control the relationship to make sure that there was planning continuity. This required a significant effort because of high turnover of commissioners at this time, and because each utility sought "stand-alone" treatment of its own construction cases on a rush basis.

Least-Cost Planning and the Future

Measured by the accuracy of capacity planning, the most serious deficit in the results of our last ten years is excess capacity. Interestingly, this provides an opportunity that will be a serious test of our process over the next ten years. Least-cost planning requires much more continuous and complicated process than the capacity planning begun in 1975. It also requires continuous interaction between the planning process and construction and rate cases.

For example, currently our largest utility brought before us a major life extension proposal to refurbish four units with atmospheric fluidized bed combustion at a cost of about $500 million. This project received wide acclaim, including that from members of the commission, because it helps address problems of SO2 emission and acid rain.

Nonetheless, to the chagrin of the utility, after the initial euphoria passed, it became clear to the commission that these plans could not merely be viewed as a construction project. They needed to be examined in a least-cost planning framework, weighing whether demand alternatives such as conservation would be cheaper, permitting deferral of all or part of the proposal. The commission had to press the utility to do at least a truncated version of a least-cost plan before a full-fledged one is developed for our next advance plan process.

The fluidized bed proposal also led the commission recently to make a decision in the company's rate case to authorize a ten-fold increase in dollars escrowed for the utility's conservation program to allow flexibility for the conservation option to be considered seriously in the upcoming construction approval case. Truly, the planning process is now ubiquitous, as our staff keeps forcibly calling to our attention. This staff, comprising about 15 people working on least-cost planning and conservation issues, is now a seasoned group of veterans, the greatest asset a commission can have and one that is only developed through the fires of trial, error, and hard work.

I should add that the advance planning process has led to growth in planning sophistication in both commission and utilities' staff. The emphasis of the advance planning law was to open up the
utility planning process. As that occurred, and as commission staff asked more questions and requested more data, the utilities' staff people were forced to plan at a much more sophisticated level. It has been a mutually reinforcing process as the level of learning and sophistication of commission and utility staff has grown through the years, and the overall advance planning process has become much stronger as a result.

Competition and the Planning Process

Another challenge to the planning process is a potentially more competitive industry environment. Here our comments must be speculative, as Wisconsin to date has not been confronted with an influx of co-generation or other competitors, given that our utilities' prices are lower than the average in the Midwest and that our excess capacity leads to low avoided cost rates.

Unless or until there is no obligation to serve, it would appear a planning effort can only be an advantage. Our process includes estimates of potential conventional and alternative supply from nonutility as well as utility sources. Additional uncertainty may be created as the percentage of supply from nonutility or out-of-state utility sources increases, but that is different from the uncertainties faced today in degree only.

Nothing precludes competition from occurring in a planning process. In fact, our utilities have been ordered to develop rates to encourage customer-owned generation and self-generation, including a standard levelized contract. It is easier to visualize competition occurring in an active regulatory climate than in a passive one. With planning which requires a search for the least-cost option, nonutility sources have a clear and valid role. The significant questions are whether they can provide the service at a lower cost than the utility and whether a system including those sources will provide service reliably. In a weak or passive regulatory climate the utility may use its monopoly power to protect itself from competition, with resultant economic inefficiency.

The commission and our utilities are not likely to be taken by surprise by an influx of large nonutility sources since Wisconsin statutes require that any producer of electricity larger than 12 mW receive planning and certificate approval from the commission prior to constructing the facility. This regulatory responsibility puts both utility and nonutility sources on the same basis from a planning perspective and provides a level playing field for competition.

Potentially more troublesome from a commission planning perspective is competition among our utilities. Currently, there is increasing competition for wholesale municipal load among our utilities. This makes it somewhat more difficult for the commission to carry out its obligation to assure a least-cost transmission system, as the utilities are sometimes more reluctant to do joint planning.

However, as the nonutility sources of supply grow, and the interutility competition or competition from out-of-state sources of supply increases, the utility's own internal planning process for supply will be affected. A greater premium will need to be placed on flexibility and the ability to bring on sources of supply in smaller increments. It is partly with this in mind that our commission is concerned about the incentives for our utilities to develop demand alternatives, such as conservation, which come in smaller increments. We also see these incentives as critical to creating a level playing field between demand and supply options.

The commission looked generically at financial incentives in a recent rate case. The order found that it was necessary to treat conservation on a par with plans investment. In the rate case we specifically ordered a current return on longer term conservation investments in loans and rebates for our largest electric utility. We also decided to provide for a performance incentive of an additional one percent return on conservation investment for 125 megawatts saved and two percent for 250 megawatts. We intend to look further into ways to adjust sales related to achieved conservation in subsequent rate cases and into other ways to encourage conservation by financial incentives which promise to be more effective than prescriptive means.

Again, these decisions show the flow between our planning process and issues such as return on capital and rate design. The interrelationship between rate design and the evolution of our least-cost planning process has been a significant theme of the last ten years. The implementation of marginal cost pricing at the commission, which had begun before the power plant siting law, was assisted by the initiation of the advance planning process. The information filed by the utilities in the advance plan process has been very useful in developing marginal costs, avoided costs, and
rate design. In turn, the fact that marginal cost principles underlie the rate structures of the major electric utilities is an important underpinning of least-cost planning, at least to the extent that the planners can be more assured that there are few or no distortions in demand due to price distortions.

It is also important to note that Wisconsin has complemented the advance plan process with the development of long-range financial planning forecasts by our major electric utilities. These enable us to model the effect of major decisions of demand and supply options on the utility's capital structure and cash flow.

These tools are becoming especially important as our major electric utilities begin some diversification. Least-cost planning and long-range financial planning are a potent combination to assist us in maintaining healthy utilities that continue to provide low cost, reliable service. These sophisticated planning mechanisms are a far cry from the crude capacity planning begun little more than ten years ago. It is exciting to think what the chair of the Wisconsin commission may say at this conference ten years from now!

Least-Cost Energy Strategies and Rate Design

Robert M. Spann

The electric utility industry is in a state of transition. The environment within which utilities operate is changing substantially. The changes that have occurred in the last two years and the changes that will probably take place in the next five years are as great, and may be as important, as the changes in conditions facing the industry which occurred during the 1970s. For example, imports of electricity from Canada are now an issue in U.S. trade debates. There has been a substantial increase in competition for wholesale business. We are seeing much larger volumes of interchange between utilities as various utilities attempt to market surplus capacity at prices above variable production costs. There is now some competition for retail load in certain parts of the country. Many utilities have surplus capacity and little or no requirement to begin construction of new capacity until some time in the next decade.

The appropriate rate design and pricing strategies for an electric utility depends on economic, supply and demand conditions facing the utility at a particular point in time. As a general rule,
rate design strategies depend on the relationship between the utility's incremental costs—the increase in its costs resulting from producing an additional kwh—and the revenues that can be realized from sales of additional kwh. The appropriate rate designs also depend on the utilities existing capacity relative to the demand for its product.

When the utility can produce additional kilowatt-hours at an incremental cost less than the revenues which are currently received from the sale of electricity, it is in the interest of both the utility ratepayer and shareholders to increase sales of electricity. This will generally occur when the utility has sufficient capacity to meet its load and could meet even higher loads with existing capacity. When the incremental costs of producing additional kilowatt-hours exceed the revenues that can be realized from additional sales of electricity, it is in the interests of both ratepayer and shareholders to curtail the usage of electricity. This will generally occur when additional sales require the addition of new capacity and the cost of constructing new capacity substantially exceeds the accounting cost of existing capacity and/or during periods when the cost of incremental fuel (that is, the cost of running the highest cost generator) substantially exceeds the utility's average fuel costs.

The remainder of this paper addresses the appropriate rate designs for implementing least cost energy plans given the economic conditions facing utilities in the 1980s. I shall first review those conditions as well as the basic principles of rate design and then discuss specific rate designs for today's conditions.

Factors Influencing Rate Design in the 1980s

There are a number of key factors influencing rate design in the 1980s. First, and most important, the incremental cost of producing additional kilowatt hours is equal to or less than retail rates. This differs substantially from the 1970s and early 1980s when almost all utilities faced short run incremental costs in excess of retail rates.

Competition in the electric utility markets will continue to increase. It is worth remembering that in 1950, when there was no PURPA legislation and no emphasis on alternative energy technologies, 50 percent of all electricity consumed by U.S. industries was not generated by electric utilities. It was produced via cogeneration or self-generation. While some of that self-generation was a result of emergency capacity added in World War II the great bulk was simply economic cogeneration. Similarly, much of the industrial cogeneration we see today is in response to high retail rates—not high avoided cost rates.

Figure 1 shows the ratio of natural gas prices to electricity prices from the period 1960-1984. During most of the 1960's the ratio of retail natural gas prices to electric rates did not change much. During the 1970s retail natural gas rates doubled relative to electric rates. In other words, the price of electricity relative to a competitive fuel natural gas, fell by 50 percent. That helped maintain electric load growth during the 1970s when electric rates were increasing. As a result, electricity's market share increased during the 1970s. This trend has changed. Gas prices have been falling for the last two years. Retail natural gas distribution companies are out in the market place actively competing with electric utilities for business.

Competition between utilities is increasing as well. Utilities are competing for wholesale business on the economy interchange market. Utilities are actively seeking new industrial loads and are once again attempting to attract new large loads. All of these changes in the utility environment need to be recognized in the rate design process and made part of least cost planning efforts.

Rate Design and Least Cost Planning

The appropriate rate design and pricing strategies to implement least cost planning depend on economic, supply and demand conditions facing the utility at a particular point in time. As a general rule, rate design strategies depend on the relationship between the utility's incremental costs—the increase in its costs resulting from producing an additional kwh—and the revenues that can be realized from sales of additional kwh. The appropriate rate designs also depend on the utilities existing capacity relative to the demand for its product.

When the utility can produce additional kilowatt-hours at an incremental cost less than the revenues which are currently received from the sale of electricity, it is in the interest of both the utility ratepayer and shareholders to increase sales of electricity.
This will generally occur when the utility has sufficient capacity to meet its load and could meet even higher loads with existing capacity. When the incremental costs of producing additional kilowatt-hours exceeds the revenues that can be realized from additional sales of electricity, it is in the interests of both ratepayer and shareholders to curtail the usage of electricity. This will generally occur when additional sales require the addition of new capacity and the cost of constructing new capacity substantially exceeds the accounting cost of existing capacity and/or during periods when the cost of incremental fuel (that is, the cost of running the highest cost generator) substantially exceeds the utility’s average fuel costs.

In determining the appropriate rate designs, it is also important to remember that a utility’s costs can vary substantially by time of day and season. In the case of a summer-peak utility, increased summer sales during daytime peak periods increase peak demand. In the long run this requires the addition of generating capacity. In addition, increased summer sales require the utility to run high incremental cost generators. The economics of increased winter sales and/or off-peak sales during the summer are quite different. Increased winter sales and/or off-peak summer sales can be met by running existing coal fired capacity and do not require additions of new generating plants.

The relationship between incremental costs and rate design can be illustrated with two simple examples.

If the utility’s incremental costs are 8 cents and the retail rate is 6 cents, additional sales of electricity increase revenues by 6 cents per kwh but costs increase by 8 cents per kwh. In this case there is a “loss” of two cents per kwh each time sales increase. This “loss” results in either reduced earnings per share or requires a rate increase in order to maintain the utility’s overall rate of return. As a result both ratepayer and shareholders are better off if the utility seeks to reduce sales or avoid growth in output. The utility can actually make both ratepayer and shareholders better off by investing in conservation/load management programs which curtail growth in demand. Each conserved kwh is worth 2 cents and the utility can afford to make investments with annual revenue requirements up to 2 cents per saved kwh and still have conservation investments lower overall average rates.

The same logic applies when incremental costs are less than retail rates. If the utility’s incremental costs are 3 cents per kwh and it can increase its sales at a price of 4 cents per kwh (but the increased sales could not be obtained at a higher price), then the benefits are 1 cent per kwh times the increase in sales. This increased coverage of fixed costs results in increased pretax profit for shareholders or can be used to reduce rates to all ratepayers while still maintaining the same rate of return to shareholders.

Figures 2 and 3 illustrate the impact of increased sales under the current surplus conditions facing many utilities today. Figure 2 refers to the impact on average rates. The horizontal axis is the percentage increase in sales. The vertical axis on the left hand graph is percent decrease in rates. Two cases are shown, a sixty percent markup and a 20 percent markup. By markup I mean the percentage by which an incentive rate exceeds the utility’s short run incremental costs. This figure indicates that, at a 60 percent markup for increased sales, a four percent increase in sales results...
in a two percent decrease in overall rates. At a 20 percent mark-up, a four percent increase in sales leads to a 0.5 percent reduction in overall rates.

Percent Decrease in Rates

Figure 2.

Figure 3 assumes that the benefits of increased sales are retained by shareholders rather than flowed thru to ratepayer. At a 60 percent markup a 4 percent increase in sales leads to a 1.5 percentage point increase in earned equity returns, that is, moving from a 13 percent rate of return on equity to a 14.5 percent rate of return on equity. Both of these Figures assume that marginal cost are less than retail rates.

Long Run Versus Short Run Issues

The concern is often raised that programs which increase sales in the near term only lead to higher costs in the long term as such programs eventually accelerate the need for new capacity. There are several reasons why this need not be the case with properly designed near term load enhancement programs.

First, where customer economics indicate that it is appropriate, incentive rates can provide for interruptable service.

Second, the load enhancement programs can be limited to the period of surplus.

Third, joint use of increased load management and increased sales. A 20 Mw addition of a high load factor customer combined with a increase of 20 Mw in winter on-peak load management has the same effect on the utility system as a 20 Mw load increase in off-peak load.

Another way to design rates that promote usage during a surplus period without encouraging permanent increases in load at revenues that do not cover the cost of new powerplants is to have flexibility in the rate structure. Ideally one would want to think of
rate structures for promotional rates today that automatically increase as the surplus goes away. One type of rate would be a form of real time pricing that is being tried by some utilities in which the electric rate at any given hour is simply short run marginal cost plus a markup. When there is a surplus, low cost generators are used more intensely and the rate will be low. As the surplus is eliminated and capacity becomes tighter, higher and higher cost machines will be used more intensely and the rate will increase automatically to reflect the new shortage conditions. Again, the key ingredient to a successful rate strategy will be knowing how the customer uses the product and providing a package that covers cost but is still more attractive than the competition.

I do not believe that there is necessarily a battle between conservation rates and promotional rates under surplus conditions. In the near term utilities will be much more successful marketing the efficient use of electricity than inefficient use of electricity. Current strategies in another energy market, the oil market is enlightening. Oil heating companies and oil distributors are not regulated. They are seeking to promote the use of their product. The two most common things advertised by oil dealers and manufacturers of oil heating equipment are: a) new highly efficient oil furnaces, i.e., efficient appliances and b) service. Finally, the economic justification of conservation and load management rates is that when usage is expensive utilities should discourage increased usage, when increased usage is inexpensive, promote use.

Other Components of Cost Effective Load Enhancement Programs

There are several steps that can be taken by a utility—particularly in the industrial and commercial area—to increase the effectiveness of load enhancement rates.

First, the rate discount should be part of an integrated package. The utility is much more familiar with state regulatory agencies, zoning boards, land availability, etc. than a new firm looking to locate a plant in the utility’s service area. As such the utility’s expertise in these areas should be of great value to firms looking at Arizona. Discussions we have had with industrial customers who have sited major plants have also indicated that if the customer can deal with one entity that can move things along expeditiously, this is a definite plus.

Second, the utility needs to treat the customer the way an unregulated supplier of raw materials treats the same firm. Industrial customers (in other parts of the country) have complained to us along the following lines “the people who sell us chemicals call on us every week to make sure things are going smoothly. The only time the utility calls me is when they want to soften us up prior to a rate increase filing.” In effect, the utility needs to treat the customer as someone to be courted, rather than the adversary in rate proceedings.

Third, utilities need to learn much more about the cost structure of its existing and potential customers and how they use electricity. The best way to attract load or to build load is to show the customer how much money he can save by locating in the utility’s territory and/or how he can reduce his operating costs by shifting to a process that uses more electricity. As a general rule, utilities may need to spend as much or more time studying the cost structure of its customers as it does studying its own costs and operations.

Fourth, the rate discounts need to be targeted “riife shoots” rather than simply broad brush discounts. Often the structure of rates and terms and conditions are as important to the customers as overall rate levels. By understanding the customer’s operations and working with the customer, the utility can offer a customer tailored rate that maximizes the benefits to the customer but is less costly to the utility than a broad brush discount.

Conclusion

Economic conditions facing utilities have changed substantially and are likely to change more in the next few years. Rate designs which were appropriate for the economic conditions of the 1970s and early 1980s are not necessarily appropriate for today’s conditions. Utilities had to adjust to a changed set of circumstances in the 1970s. They now need to adjust to the market realities of the 1980s. This will require more flexible pricing and a more customer and market oriented approach to rate design.
When Is Excess Capacity Desirable?

S. Keith Berry

Excess capacity is clearly a major issue in electric utility rate hearings. It has a major dollar effect on both ratepayers and stockholders, and it involves related questions of managerial imprudence, cost of capital effects, and intergenerational ratepayer equity. Obviously, unrealized demand is a primary reason for excess capacity today. It is important to note, however, that even when future loads can be predicted with certainty, there are sound theoretical bases for excess capacity in certain situations, when it may be beneficial for ratepayers through minimization of their revenue requirements.

This paper develops various models in which excess capacity is desirable for ratepayers even when demand is deterministic. Since demand is assumed to be known with uncertainty, we also assume that there is no need for a reserve margin. The first section considers various models with a variety of assumptions concerning fixed installation costs, inflation, and technological savings.

Note: The views expressed are not necessarily those of the Arkansas Public Service Commission or its staff.

The following section illustrates procedures that properly allocate excess capacity costs among ratepayer cohorts. The next section considers the possibility that reductions in fuel cost risk, made possible by extra capacity, may prove beneficial to ratepayers.

These models are not intended to exhaust all possibilities but to highlight some of the more significant rationales for excess capacity. The results do not imply that some excess capacity is desirable for every utility, or that ratemaking reductions to ratebase for excess capacity are inappropriate. It is hoped these models can enable regulators to distinguish when excess capacity is desirable and when it is not.

Fixed Installation Costs, Inflation, Technological Savings, and the Desirability of Excess Capacity

Assume that a utility is considering the construction of units to meet demand in the future. Furthermore, assume that there is no lead time associated with construction activity. We define the relevant variables as:

\[ L = \text{fixed installation costs}; \]
\[ v = \text{the cost of capacity per unit}; \]
\[ r = \text{the rate of carrying cost per year}; \text{ and} \]
\[ D = \text{the amount of increase in demand per year}. \]

Note that growth is assumed to be linear \((D \text{ units per year})\).\(^1\) \(L\) represents the fixed installation costs, which are invariant to the amount of capacity built, thus, the greater the amount of capacity built at any particular time, the greater the amount of units over which to spread \(L\). Of course, the countervailing factor to this is that any temporary "excess capacity" concomitantly implies "excess" carrying costs which either must be paid currently or accrued for future recovery. Thus, the question is the optimal amount of "inventory" to carry so as to minimize ratepayers' revenue requirements. For the purposes here, we assume that demand is known with certainty. The solution for \(n\), the optimum planning period, is obtained from\(^2\)

\[ L + Dv = Dv(1 + r)^n. \]  

(1)
This equates the cost of the incremental unit built now, but brought on stream \( n \) periods from now, with the cost of that incremental unit built \( n \) periods from now. Note that the unit built now, but not needed for \( n \) periods, requires carrying charges which either are paid currently by ratepayers or are accrued and paid in the future. For those units that are utilized prior to \( n \), it is cheaper to build them early. For periods greater than \( n \), the cost of carrying the incremental unit exceeds the cost of building anew (inclusive of the lumpy installation costs).

Thus, in this case, Model 1, the solution for \( n \) is given as

\[
\ln n = \frac{\ln (L + Dv) - \ln Dv}{\ln (1 + r)}.
\]  

(2)

where \( \ln \) is the natural logarithm. Note that as \( r \) increases or \( L \) decreases, \( n \) decreases. The appropriate number of units to build is \((n+1)D\). If a greater or lesser number of units are built, ratepayers’ revenue requirements are not minimized.

A simple example should help illustrate this model. Suppose that \( L = 100,000, v = 2,000, r = .02, \) and \( D = 20 \). The solution for \( n \) obtained from Eq. (2) above is 6.87. In other words, it is cheaper to build units approximately seven years ahead (and, thus, build 7.87 or approximately eight units at the beginning of the cycle). This can be seen from Table 1. In particular, note that to satisfy demand in years one through six it is cheaper for ratepayers to build ahead than wait and build when the capacity is actually needed.

A more realistic model assumes an annual inflation rate of \( i < r \), which affects both lumpy installation costs and the cost of capacity per unit. In that particular case the solution for \( n \) is obtained from

\[
(L(1+i)^n + Dv(1+i)^n) = Dv(1+r)^n.
\]

(3)

In this Model 2, the solution for \( n \) is

\[
\ln n = \frac{\ln (L + Dv) - \ln Dv}{\ln (1 + r) - \ln (1 + i)}.
\]

(4)

For \( r > i > 0 \), the solution for \( n \) in Eq. (4) is greater than the solution for \( n \) in Eq. (2). This is because there is now an additional advantage to building early: beating inflation. Furthermore, as \( i \) increases, \( n \) increases.

Using the same example as before, with \( i = .05 \), the solution for \( n \) is 9.38. Table 2 shows those results year by year. Note that for years two through nine it is cheaper to build early. This points out that the inclusion of inflation in the model tends to increase the amount of desirable excess capacity.

A more complex model, Model 3, assumes that there are improvements in technology with the addition of new plant. That implies there are some technological savings in variable costs (for example, fuel savings) associated with building early. However, for these purposes we assume that the fuel savings cease to exist in the year when the plant would have been built to meet demand anyway. The solution for \( n \) is obtained from

\[
L(1+i)^n + Dv(1+i)^n = Dv(1+r)^n - \sum_{j=0}^{n} (1+r)^{-j} (1+i)^{n-j-1}.
\]

(5)

\( E \) is the technological savings in year 0, and \( 1+i \) is the amount by which \( E \) increases each year due to inflation. This equation can
Table 2. Example from Model 2

<table>
<thead>
<tr>
<th>Year for which units are built early</th>
<th>No. of units built early</th>
<th>Cost if built early</th>
<th>Cost if built anew in year needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>20</td>
<td>$140,000</td>
<td>$140,000</td>
</tr>
<tr>
<td>1</td>
<td>20</td>
<td>48,000</td>
<td>147,000</td>
</tr>
<tr>
<td>2</td>
<td>20</td>
<td>57,600</td>
<td>154,350</td>
</tr>
<tr>
<td>3</td>
<td>20</td>
<td>69,120</td>
<td>162,068</td>
</tr>
<tr>
<td>4</td>
<td>20</td>
<td>82,944</td>
<td>170,171</td>
</tr>
<tr>
<td>5</td>
<td>20</td>
<td>99,533</td>
<td>178,079</td>
</tr>
<tr>
<td>6</td>
<td>20</td>
<td>119,459</td>
<td>187,013</td>
</tr>
<tr>
<td>7</td>
<td>20</td>
<td>143,327</td>
<td>195,994</td>
</tr>
<tr>
<td>8</td>
<td>20</td>
<td>171,953</td>
<td>206,844</td>
</tr>
<tr>
<td>9</td>
<td>20</td>
<td>206,391</td>
<td>217,186</td>
</tr>
<tr>
<td>10</td>
<td>20</td>
<td>247,069</td>
<td>218,046</td>
</tr>
</tbody>
</table>

* For years one on, cost is calculated as $40,000(1.2)^j$, where $j$ is the year.
** Calculated as $140,000(1.05)^j$, where $j$ is the year.

be solved for $n$ as

$$n = \frac{\ln |L + Du - E(1 + r)/(r - i)| - \ln |Du - E(1 + r)/(r - i)|}{\ln (1 + r) - \ln (1 + i)}$$

Let $E$ be $1,000 per year in the context of our example; the solution for $n$ is then 10.61 years. Note that the productivity benefits of early building tend to encourage even greater excess capacity. These results are shown in Table 3.

Ratepayers' Intergenerational Equity

In all of the above models, the ratepayers are clearly better off with some excess capacity. We now need to address the question of the appropriate distribution of costs among ratepayer generations. A reasonable starting point is to assume that ratepayers' costs in any year, $j$, should be proportional to $(j + 1)^D$.

In Model 1 the present value of ratepayers' costs during the

Table 3. Example from Model 3

<table>
<thead>
<tr>
<th>Year for which units are built early</th>
<th>No. of units built early</th>
<th>Capital cost built early</th>
<th>Fuel savings</th>
<th>Net cost year needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>20</td>
<td>$140,000</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>1</td>
<td>20</td>
<td>48,000</td>
<td>1,200</td>
<td>46,800</td>
</tr>
<tr>
<td>2</td>
<td>20</td>
<td>57,600</td>
<td>2,700</td>
<td>54,900</td>
</tr>
<tr>
<td>3</td>
<td>20</td>
<td>69,120</td>
<td>4,563</td>
<td>64,557</td>
</tr>
<tr>
<td>4</td>
<td>20</td>
<td>82,944</td>
<td>6,865</td>
<td>76,079</td>
</tr>
<tr>
<td>5</td>
<td>20</td>
<td>99,533</td>
<td>9,696</td>
<td>89,837</td>
</tr>
<tr>
<td>6</td>
<td>20</td>
<td>119,459</td>
<td>13,167</td>
<td>106,272</td>
</tr>
<tr>
<td>7</td>
<td>20</td>
<td>143,327</td>
<td>17,400</td>
<td>125,918</td>
</tr>
<tr>
<td>8</td>
<td>20</td>
<td>171,953</td>
<td>22,579</td>
<td>149,374</td>
</tr>
<tr>
<td>9</td>
<td>20</td>
<td>206,391</td>
<td>28,868</td>
<td>175,523</td>
</tr>
<tr>
<td>10</td>
<td>20</td>
<td>247,069</td>
<td>35,920</td>
<td>211,149</td>
</tr>
<tr>
<td>11</td>
<td>20</td>
<td>297,303</td>
<td>45,758</td>
<td>251,445</td>
</tr>
</tbody>
</table>

* For years one on, capital cost is calculated as $40,000(1.2)^j$, where $j$ is the year.
** Calculated as $140,000(1.05)^j$, where $j$ is the year.

planning period is

$$[L + (n + 1)Du](1 + r)^n \sum_{j=0}^{n} \left( \frac{1}{1 + r} \right)^j$$

$$= [L + (n + 1)Du](1 + r) \left[ 1 - \left( \frac{1}{1 + r} \right)^{n+1} \right]$$

Since demand and, therefore, billing determinants are growing at an amount of $D$ per year, the costs picked up by ratepayers must grow by the same amount in order to meet the proportionality constraint. The amount of cost increase per year that ratepayers must bear, $C$, is obtained from

$$[L + (n + 1)Du](1 + r) \left[ 1 - \left( \frac{1}{1 + r} \right)^{n+1} \right] = \sum_{j=1}^{n} \left( \frac{jC}{(1 + r)^{j-1}} \right).$$
Table 4. Ratepayer Costs in Model 1

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital costs</th>
<th>Ratepayer costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$82,069</td>
<td>$23,436</td>
</tr>
<tr>
<td>1</td>
<td>82,069</td>
<td>40,872</td>
</tr>
<tr>
<td>2</td>
<td>82,069</td>
<td>73,308</td>
</tr>
<tr>
<td>3</td>
<td>82,069</td>
<td>93,744</td>
</tr>
<tr>
<td>4</td>
<td>82,069</td>
<td>117,180</td>
</tr>
<tr>
<td>5</td>
<td>82,069</td>
<td>140,516</td>
</tr>
<tr>
<td>6</td>
<td>82,069</td>
<td>164,052</td>
</tr>
</tbody>
</table>

C is solved as

\[
C = \frac{[L + (n + 1)Dv][1 - \left(\frac{1}{1+r}\right)^{n+1}] \left(\frac{r}{1+r}\right)}{1 - (n + 2)\left(\frac{1}{1+r}\right)^{n+1} + (n + 1)\left(\frac{1}{1+r}\right)^{n+2}}. \tag{9}
\]

Using the parameters from our example, \(C = 23,436\). Thus, example, costs flowed through to ratepayers should increase by $23,436 per year. This is shown in Table 4, with a comparison of the actual capital costs incurred each year.

In a similar fashion it can be shown that, in Model 2, \(C\) is calculated from the following equation:

\[
[L + (n + 1)Dv][1 + r] \left[1 - \left(\frac{1}{1+r}\right)^{n+1}\right] = \sum_{i=1}^{n+1} \frac{JC(1 + i)^{-1}}{(1+r)^{i-1}}.
\]

This yields

\[
C = \frac{[L + (n + 1)Dv][1 - \left(\frac{1}{1+r}\right)^{n+1}] \left(\frac{r-1}{1+r}\right)}{1 - (n + 2)\left(\frac{1}{1+r}\right)^{n+1} + (n + 1)\left(\frac{1}{1+r}\right)^{n+2}}. \tag{11}
\]

In this case, \(C\) is calculated as $19,282. This means that in year \(j\) ratepayers' costs associated with this building cycle are \((j + 1)(19,282)(1.05)^j\). In other words, the costs picked up by ratepayers should increase each year due to greater billing determinants and inflation. This is shown in Table 5.

Table 5. Ratepayer Costs in Model 2

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital costs</th>
<th>Ratepayer costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$103,054</td>
<td>$19,282</td>
</tr>
<tr>
<td>1</td>
<td>103,054</td>
<td>40,492</td>
</tr>
<tr>
<td>2</td>
<td>103,054</td>
<td>63,775</td>
</tr>
<tr>
<td>3</td>
<td>103,054</td>
<td>89,285</td>
</tr>
<tr>
<td>4</td>
<td>103,054</td>
<td>117,187</td>
</tr>
<tr>
<td>5</td>
<td>103,054</td>
<td>147,656</td>
</tr>
<tr>
<td>6</td>
<td>103,054</td>
<td>180,878</td>
</tr>
<tr>
<td>7</td>
<td>103,054</td>
<td>217,054</td>
</tr>
<tr>
<td>8</td>
<td>103,054</td>
<td>258,395</td>
</tr>
<tr>
<td>9</td>
<td>103,054</td>
<td>299,127</td>
</tr>
</tbody>
</table>

In Model 3 the calculation of plant costs should consider the reduction in variable costs due to technology gains. Those gains decrease the "net" plant costs. The present value of the net plant costs (that is, net of technological savings) in this model is

\[
[L + (n + 1)Dv][1 + r] \left[1 - \left(\frac{1}{1+r}\right)^{n+1}\right] - (n + 1)E \sum_{j=0}^{n} \frac{(1 + i)^j}{(1 + r)^{j+1}}
\]

\[
= [L + (n + 1)Dv][1 + r] \left[1 - \left(\frac{1}{1+r}\right)^{n+1}\right] - (n + 1)E \left[\frac{1 - \left(\frac{1}{1+r}\right)^{n+1}}{1 - \left(\frac{1}{1+r}\right)}\right]. \tag{12}
\]

Let the above expression be labelled S. \(C\) is calculated as

\[
C = \frac{S \left(\frac{1}{1+r}\right)^2}{1 - (n + 2)\left(\frac{1}{1+r}\right)^{n+1} + (n + 1)\left(\frac{1}{1+r}\right)^{n+2}}. \tag{13}
\]
Table 6. Ratepayer Costs in Model 3

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital costs</th>
<th>Fuel savings</th>
<th>Net costs</th>
<th>Ratepayers' costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$112,898</td>
<td>$11,612</td>
<td>$101,286</td>
<td>$17,014</td>
</tr>
<tr>
<td>1</td>
<td>112,898</td>
<td>13,133</td>
<td>100,755</td>
<td>31,279</td>
</tr>
<tr>
<td>2</td>
<td>112,898</td>
<td>12,809</td>
<td>100,086</td>
<td>34,274</td>
</tr>
<tr>
<td>3</td>
<td>112,898</td>
<td>12,443</td>
<td>99,455</td>
<td>37,765</td>
</tr>
<tr>
<td>4</td>
<td>112,898</td>
<td>14,115</td>
<td>98,783</td>
<td>105,403</td>
</tr>
<tr>
<td>5</td>
<td>112,898</td>
<td>14,820</td>
<td>98,078</td>
<td>130,388</td>
</tr>
<tr>
<td>6</td>
<td>112,898</td>
<td>15,562</td>
<td>97,336</td>
<td>155,603</td>
</tr>
<tr>
<td>7</td>
<td>112,898</td>
<td>16,340</td>
<td>96,558</td>
<td>191,523</td>
</tr>
<tr>
<td>8</td>
<td>112,898</td>
<td>17,157</td>
<td>95,741</td>
<td>220,237</td>
</tr>
<tr>
<td>9</td>
<td>112,898</td>
<td>18,014</td>
<td>94,884</td>
<td>265,943</td>
</tr>
<tr>
<td>10</td>
<td>112,898</td>
<td>18,915</td>
<td>93,983</td>
<td>304,854</td>
</tr>
</tbody>
</table>

Using the parameters from our example, $C = 17,014$. C implicitly includes the effects of any technological savings. Thus, in period $j$, ratepayers' net costs associated with the new plant are $(j + 1)(C/105)$, as shown in Table 6.

Excess Capacity as a Means of Reducing Variable Cost Risk

The addition of excess capacity may also serve to reduce the risk of variation in variable costs (such as fuel costs), in addition to any reduction in average variable costs. This could prove beneficial to ratepayers. Consider that a utility is contemplating the addition of excess capacity to reduce average fuel cost and fuel cost variability. Let $q_1$ be the number of units of consumption, $p$ be the probability that the variable cost per unit is $z$, and $1 - p$ be the probability that the variable cost per unit is $y > z$. On average, the variable cost per unit is $pz + (1 - p)y$, and the range in variable unit cost is $(x, y)$.

Assume that if a "new" unit of production is added it would have a variable cost per unit of $z = px + (1 - p)y$. Note we have assumed that its cost is equal to the expected fuel cost of the "old" units. Furthermore, posit that the new unit of production can produce $q_2 < q_1$ units for consumption. When $z$ is the variable cost of the "old" capacity, the utility utilizes none of the new capacity (since $z < x$). Conversely, when $y$ is the variable cost of the "old" capacity, the utility will employ all of the "new" capacity, which displaces some of the old units. The utility switches between old and new units depending on the variable cost of the old units. Since this new unit of production will displace $q_0$ old units of production when the variable cost is $y$, the range in variable unit cost is

$$x, q_0z + (q_1 - q_0)y, q_1.$$

Since $z < y$, the above range is a subset of the range $(x, y)$. If either investors or ratepayers are risk averse, this reduction in risk can be beneficial to ratepayers.

The key questions are the "value" of both that reduction in risk and reduction in average variable cost, and how that value compares to the cost of the excess capacity. If that value, which is either directly or indirectly flowed through to ratepayers, is greater than the cost of the excess capacity, then the excess capacity can be considered desirable.

There are two fundamental ways in which the reduction in variable cost risk can benefit ratepayers: a reduction in the utility's cost of capital or a reduction in the "price-risk" that ratepayers face.

Let us assume that all fluctuations in unit variable cost are absorbed by stockholders, so that ratepayers face a constant unit variable cost, $x$. The cost of capital of stockholders (and paid by ratepayers) is a function of that risk. Let $k_1$ be the cost of capital without the addition of the excess unit of production (Scenario A), and let $k_2 < k_1$ be the cost of capital with the addition of the excess unit of production (Scenario B). This is illustrated in Figure 1. In that figure, we have assumed that investors are risk-averse with regard to the cost of capital. The investors' risk function is given by the curve $CC'$. In order for investors to obtain the same "utility" from a risky environment as from a risk-free environment, they require a higher return.

Assume that the rate base in Scenario A is given as $B$ and the rate base in Scenario B is $B + E$, where $E$ is the amount of new capacity. Under Scenario A, the range in return is

$$k_1 - \frac{(y - z)q_1}{B}, k_1 + \frac{(x - z)q_1}{B}.$$
to price. Ratepayers require a lower price when there is greater price risk in order to maintain the same level of utility. This is indicated by the shape of $HH'$. Under Scenario C (no excess capacity) the price range faced by ratepayers is

$$
\left( \frac{K_0 B}{q_1} + x, \frac{K_0 B}{q_1} + y \right)
$$

(17)

This is shown as $ZZ'$ in Figure 2. $U_1$ is the expected utility associated with this price range. With Scenario D (excess capacity), the price range faced by ratepayers is

$$
\left[ \frac{K_0 (B + E)}{q_1} + x, \frac{K_0 (B + E)}{q_1} + \frac{q_0 x + (q_1 - q_0) y}{q_1} \right]
$$

(18)

This is given by $WW'$ in Figure 2, with an expected utility of $U_2$.

Depending on the ratepayers' utility function, the amount of excess capacity, the reduction in average fuel cost, and the reduction in fuel cost variation, it may or may not be desirable to add excess capacity. As drawn in Figure 2, since $U_2 > U_1$, excess capacity is beneficial.6

Conclusion

This paper has demonstrated that in certain situations excess capacity can be beneficial to ratepayers. For example, when lumpy installation costs are present, excess capacity can be desirable. The assumptions of inflation and technological savings make even more excess capacity desirable. However, constructing excess capacity primarily for future cohorts of ratepayers implies that the cost of that excess should be appropriately borne by those same generations. This means the development of various types of phase-in plans.

It can also be shown that if the addition of excess capacity results in a reduction in variable cost risk, that reduction may be beneficial to ratepayers. Those benefits would either flow directly through a reduction in price risk or indirectly through a reduction in the cost of capital.
5. It can be shown, under certain reasonable assumptions, that $k_2$ is necessarily less than $k_1$. Interestingly, under those same assumptions, as the cost of excess capacity increases (for any given reduction in risk), $k_2$ becomes smaller.

6. A more complicated model could be developed whereby the optimal amount of excess capacity is determined; that is, what level of excess capacity maximizes the ratepayers' utility function.

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**Notes**

1. We could consider exponential growth as well. The qualitative results will not differ from those of the linear model.

2. This is the model developed by Eli Schwartz in "Excess Capacity in Utility Industries: An Inventory Theoretic Approach," *Land Economics* (February 1984); pp. 40-48. However, Schwartz did not consider the possibility of inflation or productivity growth. Furthermore, the models considered here are not steady-state models, which would have different solutions for $n$, but the same features are obtained in those simpler models.

3. If we assume that the increase in inflation from zero to $i$ increases $r$ by a corresponding amount, the solution for $n$ in this case is the same as in Eq. (2).

4. This approach implies some sort of phase-in plan. There are at least two other reasonable methods for allocating costs between generations. First, plant can be added to ratebase as it is needed (with humpy installation costs added in the first year). This was discussed by Schwartz. Second, all the plant can be included in ratebase at the beginning of the cycle.
utility rates. Thus, increased sales harmed ratepayers by increasing costs faster than revenues; regulators found themselves encouraging conservation and other demand-side programs to lower demand growth and had utilities halt marketing and incentive programs and institute rate designs encouraging conservation. Regulators also found independent power producers attractive, helping to decrease the use of marginally efficient utility plants and benefiting ratepayers. Finally, utilities were allowed to proceed with power plants where needs remained unmet or where new plants were cheaper than the operating costs of old plants.

During 1985–1986, oil and gas prices fell and new utility capacity, planned during the energy crisis, began to come on line. As a result, marginal costs are again below average rates, at least in the short run; thus, stimulating demand growth can again benefit utility ratepayers. However, we are also now more cognizant of the long-run effects short-run demand growth can have; even though using excess capacity is a good idea for ratepayers, if it results in greater than necessary capacity needs in the long run, regulators may want to be cautious.

In California, on the supply side, the commission is working to integrate the consideration of utility-owned generation, independent power purchases, and out-of-state power purchases in order to fill the gap at the least cost. This has been accomplished through the recent commission decision on the form of long-run standard offers for qualifying facilities.

The offers are based on utility resource plans, including planned demand-side investment; the specific focus is on utility plans for cost-effective construction to meet demand growth within an eight-year horizon. QFs receive the estimated capital and operating costs of the utility plant that is deferred by QF power. QFs can be on line before the deferred plant would have been, but they only receive short-run avoided costs until the plant would have been on line. If the offer is oversubscribed, that is, the size of QFs wanting the offer is greater than the size of the deferred plant, QFs bid for the offer. If no QFs accept the offer, the utility is entitled to build the plant.

Out-of-state producers have two choices: They can wait until the offer has been made available to QFs and sign a contract to sell power for the amount of deferred need QFs do not sign up for; or they can sign a contract with the utility before the resource
plan is submitted to the utility at a lower price. Essentially, they can try to obtain a high price and risk getting no contract (if QFs meet the need), or they can take a much lower price and be assured some market for their power. The commission feels that out-of-state sellers can maximize revenues only by signing contracts early and at low prices.

On the demand side, the commission emphasis in recent years has been in the area of revenue allocation and rate design. The goal is to use prices to signal customers on the optimal investments in demand-side reductions. This includes time-of-use rates (mandatory for industrial customers, optional for other classes) and a movement to a cost-based revenue allocation methodology. The focus recently is on rate designs which minimize bypass; given existing economic conditions, with rates greater than marginal costs, customers leaving the utility system force a greater burden of fixed costs on remaining ratepayers.

Over the last few years the commission has begun to use long-run marginal costs as a price signal to customers for optimal long-run investments. However, long-run marginal costs are currently greater than short-run marginal costs; by pricing based on long-run costs, we are missing opportunities to sell power to customers and increase revenues in the short run.

Flexible rates are another option for responding to the bypass threat and increasing the efficiency of our system. Current rates are greater than self-generation costs for some customers, an incentive for these customers to go off the system. But the vast majority of these customers' costs are greater than the utilities' short-run costs; thus, the utilities could price just below the self-generators' marginal costs, keep them on the system, and maintain a contribution to fixed costs. Flexible pricing would give the utility the authority to vary prices to some customers depending on the cost of their alternatives. The problem is that, with California's unique blend of protective balancing accounts, the utility has no incentive to negotiate a good deal; the risk is on ratepayers. The commission is exploring alternatives which would put more of the risk on the utility and give them an incentive to negotiate effectively with potential self-generators.

Part Six

Avoided Cost and Cogeneration Issues in Electricity
The Competitive Cost Advantages of Cogeneration

Jan Hamrin

What if electric utilities never had to build another power plant? How would the utility world be different? What would be the effects upon the ratepayers, utility shareholders, and the quality of regulation? What types of questions should the various parties be asking, and is there any information which can be of assistance now in evaluating the option of electric generation being supplied by independent (nonelectric utility) producers?

When PURPA was passed it was thought that stimulating the development of “ cogeneration” (defined as all the Qualifying Facility [QF] technologies) was a good thing to do. But beyond that, PURPA was passed more on faith than on knowledge of its real potential effects. Since that time, there has developed much greater understanding of the costs, benefits, and serendipitous effects, some of which had not been previously contemplated. One of the most significant of these effects has been to bring major changes to the electric utility industry. This presentation does not include the litany of reasons given for the original passage of PURPA. Rather, it focuses on the tangible things we have learned about this approach to electric generation supply since passage.
The Competitive Advantage of Qualifying Facilities

These are very uncertain times. (1) What will be the rate of growth for electricity demand in the next decade or two? (2) What will be the likely cost for oil/gas fuels in the future? (3) How available will capital be for generation expansion and at what cost? In other words, it is a time for "hedging." Whatever projections are made, they will probably be wrong. What is desirable is smaller (relative to the size of the utility system) projects with short lead times, a diversity of fuels/technologies and, if possible, a predictable price.

This is the main advantage of cogeneration, or QFs.\(^1\) They provide a hedging strategy against future uncertainties. What they do is reduce the risks to ratepayers, regulators, and utility shareholders of guessing wrong. And to repeat: One thing of which we can be certain is that we probably will guess wrong.

Uncertain Demand for Power

Because these projects have relatively short lead times, it is not necessary to make major commitments a long time in advance of need. A basic commitment for power can be made and additional offers extended to adjust for actual demand conditions. QF technologies have lead times ranging from six months to two and one-half years compared to eight to twelve years for central station plants. Furthermore, because of the nature of the technologies, many are modular and can be added in smaller increments than can most central station technologies.

Hedging against Future Fuel Prices

None of these technologies use oil, although some use indigenous fossil fuels such as natural gas. By developing a portfolio of technologies, all the eggs are not in one basket. In this way future fuel price fluctuations can be managed through a diversified mix of resources.

Capital Availability and Interest Rates

Because ratepayers and shareholders do not have to expend any capital, they do not have to be concerned about these questions. Instead, they only pay for kilowatt-hours as they are generated.

Avoiding Rate Shock and Cost Hikes

Again, ratepayers only pay for what they get. Rates are stabilized over the short term and will actually be reduced over the long term since ratepayers do not pay for: sunk costs of cancelled plants, costs of preoperative plants, cost overruns on new plant construction, construction delays and accompanying cost effects, plant failure to perform within reliability or efficiency specifications, replacement power for nonfunctioning plants, uncertain future dismantling or decommissioning costs, or capital improvement costs.

There are other benefits to ratepayers besides the transfer of the risks described above. These include the environmental benefits associated with smaller projects and many of these technologies. Also, small dispersed generation can provide jobs and economic development within a state or local area.

The Effects on Regulation

One of the serendipitous effects of PURPA has been on regulation. Avoided cost (the cost the utility would otherwise have had to spend to generate that power themselves) can be used as the common yardstick for evaluating the various options available to a utility for meeting customer demands, including conservation, load management, refurbishments, new utility generation, independent generation, firm purchases from other utilities, and so forth.

In the past, there were just the regulators and the ratepayers. If the latter said they absolutely had to begin building new generation or "ten years from now the lights will go out and everyone will freeze in the dark," regulators either had to acquiesce or face the burden that if the utility proved correct they would be held responsible. Today, instead of only two options, build or do not build, regulators can use avoided cost as a tool for providing and evaluating alternatives. A regulator can look to providing future needs through conservation, load management, purchases, or construction and choose the most cost-effective means to meet the anticipated demand. And if there are serious questions regarding the level of demand and the amount and timing of new generation, these "hedging" strategies allow the regulator to have more flexibility in dealing with the resource planning process.
Stabilizing the Price

The avoided cost yardstick allows regulators to place a cap on the costs of new generation. Should the utility choose to supply the new generation itself, it will recover only the avoided cost rate. The utility is not likely to overestimate the cost of new generation for fear it will be built by QFs who would then receive more for the power than it is worth. In the same way, underestimating the cost of new generation is dangerous to the utility in that the price might then be unattractive to QFs, thereby forcing the utility to build the facility and recover only the artificially low cost estimate.

One should not construe the above comments to mean that controversy will be removed from the regulatory arena. Determining a reliable method for measuring "avoided cost" is far from simple. And making certain the "common yardstick" is truly common and is not an elastic ruler is a time-consuming and difficult job. Nevertheless, having taken the trouble to develop and use this "common yardstick," regulators can feel more secure about their decisions once made.

Creating a Common Yardstick

Avoided cost is a mechanism for approximating the market value of electricity. Its advantage is that it can be used as an effective mechanism for obtaining energy at a fair price for ratepayers using market incentives. The disadvantage is that use of the concept is not simple or easy, but it does work incredibly well in a wide variety of circumstances, given sufficient care and thought to implementation. When used with its flip side, negative avoided cost, there are no significant limitations.

Short-term and Long-term Avoided Cost. The avoided cost concept can be used to measure short-run avoided cost (marginal operating costs and shortage costs) as well as long-run avoided cost (the capital and operating costs which would have been incurred by the utility in new generating facilities "but for Qualifying Facilities-QFs"). Part of the confusion and criticism of PURPA implementation lies in these two values—how they are computed and how they compare. Each is important and mutually compatible in measuring the present and future needs for power by a utility. The short-run avoided cost can vary significantly monthly or annually depending on the types of resources (fuels) a utility has to utilize. Long-run avoided cost can be calculated in such a way that it levels out some of the short-term perturbations (peaks and valleys) and also incorporates the potential investment in new capacity if such is needed by the utility. If no new capacity is needed during the period used for evaluation, then long-run avoided cost will simply be a projection of short-run avoided costs.

Avoided cost (both longrun and shortrun) is comprised of two components: a capacity payment and an energy payment. If the utility needs little capacity (although additional capacity always has some value through increasing the reliability of the existing system), then the capacity portion of the avoided cost payment will approach zero. There is a need for a capacity adjustment mechanism which allows avoided capacity costs accurately to reflect the utilities' changing capacity needs, reserve margin, and expectations of unserved energy requirements.

If the utility has little need for additional energy, then one would expect the short-run avoided cost for energy to be very low. However, energy is always "needed" if it is cheap enough, that is, less than what the utility is currently paying (except under conditions of negative avoided cost, when the utility does not have to purchase QF power). Thus, the avoided cost concept when properly implemented can, through the use of price signals (the essence of our economic system), encourage the production of additional generation.

Methodology for Long Run-Avoided Cost. Long-run cost, if properly implemented, should reflect either the capital and operating cost of new utility generation sources at the time they are added (otherwise known as the "proxy plant" method) or the short-run marginal cost calculated assuming the existence of these proxy resources, whichever is higher. The conceptual method for calculating long-run avoided cost is based on the simple premise that avoided cost cannot be less than the cost of a new utility generating unit. If a utility were building a plant that cost more than the avoided cost, then one of two things is wrong: Either the plant is not costeffective and should be cancelled or deferred or the avoided cost has been calculated incorrectly. This issue is less the result of in testimony in implementation of PURPA in a number of states, including California, Montana, Connecticut, and North and South Carolina.
Importance of Long-Run Avoided Cost. QF projects are generally built with an expected life of 15 to 30 years. It is difficult if not impossible to finance a capital investment of this type without some assurance of a revenue stream at least over the early period of "debt service" for the new plant. A long-run avoided cost offer provides this stability. In addition, a long-run offer allows the utility and the regulatory commission to do long-range planning which can attract QF development to avoid or defer the need for a large central station, utility power plant.

Without a long-run avoided cost methodology, the situation will shift from one in which no additional capacity is needed by a utility to one in which the utility has begun a new plant it claims "cannot now be avoided," thus eliminating the ability to interpose QF generation as an alternative.

A utility can turn the timing of its future need for capacity and the short lead times of QFs to the disadvantage of QFs. If capacity is not needed now, but is needed, for example, in six to ten years, a utility can try to discourage QF generation now. As a result, few QFs sign contracts. Then the utility commits itself to its own new generation capacity (which has to be committed early because of its longer lead time than QF capacity) and argues that the QFs cannot avoid the new capacity because it is already committed. This "Catch 22" can only be prevented through the use of long-term contracts.

Related to this issue is the claim that forecasting prices increases "risks" to ratepayers for which ratepayers must be compensated. When the issue is evaluated in its full context, it becomes clear that extra risks are not imposed on ratepayers through a long-term forecast of avoided cost. The proper evaluation must consider the utility system as a whole rather than look at QFs in isolation. If QFs are not built, the utility must add new generation. The type, timing, and amount of this new utility generation will be justified on the basis of the utility's long-term forecasts. Thus, the ratepayers do not avoid the "risk" of long-term forecasts if long-term contracts are not offered to QFs which reflect their value to the utility system. Without such contracts, QFs will simply not be built, and the ratepayers will face the risk of long-term forecasts for utility projects rather than QF projects.

Furthermore, forecasting prices in advance reduces risks by actually providing ratepayers with more certainty as to their expenses. QF payments stabilize electric rates under such conditions. Forecast prices would be overstated relative to the original projections at times ratepayers are receiving benefits from lower fuel costs and understated when utility fuel costs are high. QF payments based on forecasts of avoided costs indeed prevent the ratepayers from reaping all the benefits when actual fuel costs are lower than forecast, but, conversely, the existence of such contracts ensures the ratepayers against paying higher fuel costs if forecast costs are less than actual and higher costs for new generation if a new plant has cost overruns and/or comes in later than anticipated.

Avoided Cost as a Common Yardstick. Avoided cost and long-run avoided cost offers provide a common yardstick against which to measure various conservation and generation options. Conservation programs, refurbishments, firm power purchases, and new generation sources which are found to be "inframarginal" should, according to economic theory, be built (or funded). Other generation or purchase options are then assessed with regard to what would be used "but for QFs" and incorporated in setting a long-term avoided cost rate. If no need is found (within the planning horizon being used) for new generation, QF or otherwise, avoided costs will simply reflect short-run operating and shortage costs.

Thus, the avoided cost implementation process and methodology become useful planning tools for regulatory commissions in assessing the options utilities have before them for managing and meeting their electricity demand.

How to Keep from Getting Too Much Power. Long-run avoided cost offers based upon displaced plant(s) can be limited to the size of that plant(s) in megawatts, or a megawatt limit can be used based upon a utility's annual growth rate. When the megawatt limit is reached, new calculations are made, and a new offer (price and megawatt limit) is issued based on the new circumstances. If no additional capacity is required during the next forecast period, the "new" offer may only reflect short-run marginal operating costs until (through regular revisions) additional capacity shows up in the utility's resource plan. Thus, the use of market forces (avoided cost) works very well. When little new energy or capacity is needed, the avoided cost price will be very low. New qualifying facilities will not be cost effective under those prices
and will not be built. When the need for energy and/or capacity is greater, prices will be higher, and the private sector will respond.

The Improved Quality of Regulation

A possibly unexpected but beneficial effect of PURPA implementation is on the quality of regulation. Because the assumptions used in the calculation of avoided cost are so intertwined in the whole regulatory process, intervenors become involved in all electric utility regulatory proceedings, checking facts and figures, investigating computer models, and questioning inconsistent utility findings in various cases. Regulators have, in effect, acquired ancillary staff help. More experts are involved in all aspects of the regulatory environment. As a result of this more thorough examination of the facts, there is a better quality of regulation.

Effects on Utility Operations and Shareholders

Not all the effects from PURPA and QFs are necessarily positive. Although neither aspect about to be discussed is a fatal or insurmountable flaw, they must be acknowledged and dealt with in order to achieve the positive results desired.

The first of these complications is the integration of third party generation into the operations of the utility grid. If only one or two percent of a utility’s generation comes from independent producers, then “dispatchability” or operational options are not an issue. If, however, all future generation needs are to be supplied through independent production and if new generation will comprise fifteen percent or more of the utility’s system, it will be necessary to develop a method by which utility operational flexibility is maintained or even enhanced. This can be done through contractual “adders” or other types of requirements for specific operational characteristics. There are a number of advantages to obtaining the desired operational characteristics through the use of market incentives rather than penalties.

A second aspect which must be faced if one is seriously considering the possibility that future demand can be met more efficiently and/or less expensively by an option other than utility construction of generation is the future role of the electric utility and its shareholders. If a utility will not be building any future generation, what happens to its ratebase and returns to shareholders? Should the utility begin diversifying into other fields? Should the utility transform itself into a transmission and distribution company? Should some portion of the value of new generation (or conservation) be ratebased, even though the utility shareholders are assuming no risk in providing it?

This question of the appropriate future role of electric utilities and their shareholders is a critical one whether considering implementation of PURPA or the option of deregulation of electric generation per se. Institutions and their functions must change over time as necessary to meet changing conditions. Qualifying facilities and the avoided cost yardstick can and should be used as tools in designing new directions for the electric utility industry in the future.

Notes

1. For the purpose of this discussion, the PURPA term “Qualifying Facilities” (QFs) will be used to refer to cogeneration, biomass, geothermal, small hydro, wind, and solar electric technologies eligible to sell power to electric utilities without being regulated as a utility.

2. Negative avoided cost results when it would be cheaper for the utility to generate power itself than to accept free power from the QF. For example, at 4:00 a.m. in May, loads are low, and oil/gas and coal plants operate at a minimum. A utility is not purchasing economy energy. A purchase from a QF at this time would result in the need to shut down a plant, which would then be unable to meet load the following day without a combustion turbine.
We will explore in this paper their necessary attributes. Cost and operating characteristics of several different supply technologies will be compared to illustrate their relative competitiveness. This comparison will include conventional central station options as well as advanced and nonconventional supply options.

Industry Changes

The large central station generating plant is symbolic of the conditions that emerged from the Great Depression and ended in the early 1970s. These included relatively consistent load growth of about 6–7 percent per year. This growth was aided by aggressive marketing of electric energy and generally falling electrical energy costs. The $/kwh cost reductions were made possible by spreading fixed costs over an increasing amount of energy sales and through continued improvements in technology. Older generating plants were being replaced with ever larger and more efficient plants as improvements in materials and design allowed higher steam cycle pressures and temperatures. Regulatory and environmental requirements were relatively easy to meet or were nonexistent. Investors could expect a reasonable return, while management recognized the obligation to serve inherent in a regulated monopoly business.

The 1970s brought significant changes to the U.S. electric utility industry. There were dramatic changes in fuel cost and supply. Load growth was reduced and, in some instances, became negative. Environmental concerns and regulation increased, and electric energy costs skyrocketed.

Out of that transition period is emerging a new era for the 1980s and beyond. When compared with the postwar years, the future seems marked with increased uncertainty. Load growth is generally expected to be much lower than that experienced prior to the 1970s. There is both increased competition and increased regulation (PURPA is a good example of how these two opposing concepts can occur together). The prudence of utility decisions is increasingly called into question. Utilities will need to cope with the added risk associated with this uncertainty. The full spectrum of nontraditional supply and demand options will need to be considered, in addition to the traditional supply options, through the use of least-cost methodologies that integrate the analysis of supply- and demand-side options.
Changing Concept of Central Station Generation

The steady growth in electric power demand and continued technological improvements resulted in the design and installation of large, efficient, central station generating plants in the early 1970s. These facilities often consisted of coal and nuclear generating units in the 600 mW to 1,200 mW range. Such generating units are safe, reliable, low cost producers of energy when they are properly designed, constructed, operated, and maintained.

The changing nature of the U.S. electric utility industry, however, no longer favors these large central station plants. Their size makes it difficult to match supply additions to lower rates of load growth. For example, a system with a peak demand of 5,000 mW and a 2 percent per year growth in peak demand requires the addition of only 120 mW per year of new supply resources to maintain a 20 percent reserve margin. Large generator unit sizes also result in a system reliability that is lower than would result from installation of an equal amount of capacity composed of smaller units.

Large units often require long lead times for siting, construction, and start-up. They require a high risk commitment to begin construction as much as ten years in advance of the time the additional generation is projected to be needed. Long lead times also require construction expenditures to be at risk for a longer period. The initial capital cost of large central station plants is high, requiring a significant commitment on the part of the utility for just one generating plant—perhaps the need to “bet the company” on just one investment. The fact that the large, efficient units may have lower installed cost per kW of capacity is not enough to offset the high risk involved in such a large investment.

The large unit sizes, long lead times, and high capital costs of large central station plants make them risky investments with poor flexibility to respond to changing supply requirements. The electric power supply technologies to be used by utilities in the future will need to be added in small enough increments to better match load growth. Lead times need to be shortened to allow the commitment to install a new resource to occur closer to the time of predicted need. This is a function not only of the technology but also of the regulatory review and approval process. One example of a supply technology that has many of the positive attributes desirable for future supply requirements is the phased installation of integrated coal gasification combined cycle (IGCC). Capacity is added in relatively small increments, starting with open cycle combustion turbines, combined cycle and coal gasification phases being added at later dates only if load growth and fuel requirements warrant. Other examples of promising supply technologies are smaller standardized pulverized coal units, atmospheric fluidized bed combustion (AFBC), and pressurized fluidized bed combustion (PFBC).

These new central station technologies may result in higher energy costs compared to large efficient, technologies where economies of scale would still yield lower costs per installed unit of capacity. However, in planning for an uncertain future, the more flexible smaller central station technologies will avoid the need to “bet the company” on large blocks of resources.

Mix of Options

Future demand requirements will most likely be met by a mix of options. The number to be considered by utilities has expanded greatly. They are not limited only to those within the category of “central station generation.” Utilities now need to consider non-traditional supply options such as purchase of cogeneration and renewable energy sources, with ownership either by the utility or by others. Utilities also must consider what demand-side options may warrant investment so as to avoid at least a portion of the need for new generating capacity. Utilities should not be particularly concerned with whether the needs for electricity in the future are met with supply- or demand-side options. Their primary concern should rest in ensuring (1) that their customers have adequate supplies of safe, reliable, competitively priced energy available to them and (2) that the means of supplying that energy is done at the lowest cost, all factors considered. The method of analyzing options and strategies becomes very important to ensure that all options are measured on a “level playing field.” It is with least-cost planning techniques, in which the analysis of both supply- and demand-side options are integrated, that the best mix can be determined. It is likely this planning process will result in an array in which smaller, more flexible central station generating technologies will have a role.
Representative Supply Technologies

Information has been gathered on selected supply technologies so as to offer some comparisons among them. Basic cost and operating data for these are presented in Table 1. The choice of technologies shown is for comparison purposes only and should not be considered an endorsement of any particular technology or manufacturer. Data used are from several sources including the Electric Power Research Institute's (EPRI) 1986 Technology Assessment Guide (TAG). These data have been adapted for use by Wisconsin Electric. For example, the EPRI TAG estimate for the "total plant cost" of the 330 MW pulverized coal unit was inflated to 1986 dollars using an inflation rate of 4 percent. Start-up, inventory, and land costs were adjusted to reflect conditions more specific to Wisconsin Electric. Finally, the cost of an electrical switchyard and the cost of coal unit trains were added to the EPRI TAG costs. Therefore, the "overnight installed cost" shown in Table 1 includes plant cost, switchyard, unit train inventory, and land. It excludes AFUDC. Interest charged during construction is accounted for in the fixed charge rate discussed later. The "lead time" in Table 1 includes license, design, and construction time. The lead times shown are from the EPRI TAG with the following exceptions. One year of regulatory approval was added to the three-year lead time for the combustion turbine. The data on cogeneration technologies are not from the EPRI TAG.

The technologies selected for comparison are as follows.

Coal with FGD—conventional pulverized coal-fired power plant with wet lime flue gas desulfurization (FGD), subcritical with steam conditions of 2400 psi, 1000°F initial steam temperature with single reheat to 1000°F, and mechanical draft cooling towers.

Advanced Pulverized Coal—an extension of current technology with sliding pressure operation, maximum steam conditions of 4500 psi, initial steam temperature of 1100°F and two reheats to 1050°F, an advanced limestone based FGD system (Chiyoda Thoroughbred 121 process), and mechanical draft cooling towers. First commercial service is not expected until 1995.

AFBC—atmospheric fluidized bed combustion (AFBC) burning crushed coal in a bubbling bed of limestone, producing steam at 2400 psi and 1000°F to drive a steam turbine/electric generator.
PFBC—pressurized fluidized bed combustion (PFBC) burning crushed coal in a circulating bed of dolomite at a pressure of about 150 psi. The pressurized hot gases leaving the combustor drive a gas turbine/compressor to provide the compressed combustion air. Generated steam drives a conventional steam turbine/electric generator. First commercial service is not expected until the late 1990s.

IGCC—integrated coal gasification combined cycle (IGCC) using a gasifier to produce an intermediate BTU gas which is cleaned and burned in a combustion turbine at 2200°F. The hot exhaust gases are used to generate steam to drive a steam turbine/electric generator. The gasification process assumed is the Texaco process with quench cooling. First commercial service is expected to be available in the early 1990s.

Combined cycle—distillate oil or gas burned in a combustion turbine/electric generator with a nominal 2200°F turbine inlet temperature. The hot exhaust gases are used to generate steam to drive a steam turbine/electric generator. First commercial service is expected by 1989.

Gas/Oil Fired Steam—conventional boiler fired with distillate oil or gas to produce steam at 2400 psi, 1000°F to drive a steam turbine/electric generator.

Combustion Turbine—distillate oil or gas fired combustion turbine with a nominal 2200°F turbine inlet temperature.

Incinerator—unprocessed municipal solid waste fired on a moving grate in a waterwall incinerator to produce steam for a steam turbine/electric generator. Air emissions are controlled with an electrostatic precipitator.

Cogeneration—the two technologies used for comparison are both based on natural gas fueled internal combustion engines with turbochargers and aftercoolers driving electric generators. Waste heat is recovered from the engine exhaust and jacket cooling.

Comparison of Supply Technologies There are many methods and measures by which supply technologies can be compared. One simple way to represent both fixed and variable costs in a graphical form is the screening curve. This method has been employed for many years and allows the comparison of costs at different operating levels. Variable costs of operation include the variable or incremental operating and maintenance (O&M) expenses and the fuel costs. Fixed costs include the ownership costs and the fixed

Table 2. Financial Assumptions

| Nominal discount rate | 12.45% |
| General inflation rate | 6.13% |
| Fuel inflation—coal | 6.46% |
| Fuel inflation—natural gas | 7.22% |
| Delivered cost—coal (1986 $) | 1.29 $/MBTU |
| Delivered cost—natural gas (1986 $) | 3.30 $/MBTU |

O&M expenses. Fixed and variable operating and maintenance cost assumptions are shown in Table 1. Fuel costs are calculated using the full load heat rate values shown in Table 1 and the delivered fuel costs shown in Table 2. Using only the full load heat rate is a simplification since heat rate normally is not constant over all operating levels. The capital cost of a new unit is represented as an annual fixed cost by using a levelized fixed charge rate stated in real terms (a real levelized fixed charged rate). The calculation of the fixed charge rate takes into account the timing of construction expenditures, book and tax life of the investment, tax rates, AFUDC treatment, inflation, and discount rates. The financial assumptions used in this screening analysis are presented in Table 2. Tax rate and treatment assumptions predate the 1986 tax law changes. It is assumed that each technology has an in-service date of 1995.

The resulting real levelized fixed charge rates for the technologies compared are:

<table>
<thead>
<tr>
<th>Real levelized fixed charge rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal with FGD</td>
</tr>
<tr>
<td>Advanced Pulv. Coal</td>
</tr>
<tr>
<td>AFBC</td>
</tr>
<tr>
<td>PFBC</td>
</tr>
<tr>
<td>IGCC</td>
</tr>
<tr>
<td>Combined Cycle</td>
</tr>
<tr>
<td>Gas/Oil Fired Steam</td>
</tr>
<tr>
<td>Combustion Turbines</td>
</tr>
<tr>
<td>Incinerator</td>
</tr>
<tr>
<td>Cogeneration</td>
</tr>
</tbody>
</table>
The capacity cost expressed in dollars per kw per year can then be determined by multiplying the overnight installed cost taken from Table 1 by the real levelized fixed charge rate. The capacity cost of the 330 mw coal unit with FGD is (1322 $/kw) x (0.1010), or 133$/kw per year. Similarly, the capacity cost of the combustion turbine is (272 $/kw) x (0.1212), or 338 $/kw per year.

The screening curve analysis used here assumes a study period of 30 years with an in-service date of 1996. Future costs are projected by applying the inflation rates shown in Table 2 to the costs (capacity, fuel, and O&M) discussed above and then discounted back to 1986 dollars using the discount rate shown in Table 2.

Figure 1 is a screening curve representation of the 330 mw coal unit with FGD and the combustion turbine. It represents the annual cost of operation, in 1986 dollars per kw per year, as a function of the amount of operation, expressed as percent capacity factor. Capacity factor is the ratio of energy generated to the amount of energy that could have been generated had the unit operated at its rated capability for the entire period. The value at zero percent capacity factor reflects the sum of the levelized capacity cost discussed above and the annual fixed O&M costs. The slope of the lines is a function of the variable O&M and fuel costs. Note that the coal unit has relatively high capacity and fixed costs and low operating costs, while the combustion turbine is opposite: low fixed costs and high operating costs.

Limitations of the Screening Curve Method

It is important to be aware of the limitations of the screening curve methodology. It does not account for the availability or reliability of the technology. The ability to dispatch the technology or the ability rapidly to start up or change loads is also not accounted for. These attributes are best studied in more detail using a production simulation technique.

Another limitation is that use of the screening curve methodology does not provide information on the flexibility needed for comprehensive least-cost planning. For example, the increased flexibility and lower risk associated with shorter lead times cannot be shown. Note, however, that the financial effect of lead time is captured by the calculation of the fixed charge rate discussed previously. Finally, the screening curve methodology only addresses the basic economic costs of the technologies. It does not easily allow a comparison of externalities difficult to quantify, such as effects on health, safety, the environment, fuel use, or other social and political issues which must be considered in any selection of generation alternatives.

As a simple, graphical representation, however, the screening curve is quite useful for comparison purposes.

Screening Curve Comparisons

One traditional use of screening curves is to provide a simplistic estimate of the amount of operation at which it is less expensive to install a base-load unit rather than a peaking unit. The intersection of the coal and combustion turbine curves on Figure 1 indicates that the combustion turbine would be the less expensive option even if operated at a capacity factor as high as 40 percent. After this point, the lower operating costs associated with the coal unit favor its installation. Traditionally, this crossover point has been in the 15–25 percent capacity factor range. The improved heat rate expected of the advanced combustion turbine design
Table 3. Potential Range of Values

<table>
<thead>
<tr>
<th></th>
<th>Expected</th>
<th>Good conditions</th>
<th>Poor conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized coal, 330 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel cost, $/MBTU (+/- 20%)</td>
<td>1.29</td>
<td>1.03</td>
<td>1.55</td>
</tr>
<tr>
<td>Capital cost, $/kW (+/- 10%)</td>
<td>1322</td>
<td>1190</td>
<td>1454</td>
</tr>
<tr>
<td>Lead time, years (+/- 3 years)</td>
<td>9</td>
<td>6</td>
<td>12</td>
</tr>
<tr>
<td>Combustion turbine, 130 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel cost, $/MBTU (+/- 20%)</td>
<td>3.30</td>
<td>2.64</td>
<td>3.98</td>
</tr>
<tr>
<td>Capital cost, $/kW (+/- 10%)</td>
<td>272</td>
<td>245</td>
<td>299</td>
</tr>
</tbody>
</table>

and the relatively low current cost of natural gas help to favor the combustion turbine economics in the Figure 1 comparison. It should be noted that other coal technologies to be discussed later are lower in cost than the 330 mw coal unit shown in Figure 1.

A range of values was established to test how selected variables influence the screening curves. Fuel costs were varied by 20 percent, and capital costs by 10 percent for the 330 mw coal unit and the 130 mw combustion turbine. The lead time of the coal unit was also varied by three years. The resulting input variables are shown in Table 3 and the screening curve effects in Figure 2. These sensitivity analyses are helpful in testing the “robustness” of an alternative.

Base-Load Technologies

The representative base-load coal technologies are compared in Figure 3. Note that they are rather closely spaced and are, in fact, all within the sensitivity range for the 330 mw coal unit shown in Figure 2. The apparent advantage of the large advanced pulverized coal unit does not recognize the lower flexibility and higher risk associated with larger units, as discussed previously. The APBC and IGCC options are slightly lower cost than the traditional pulverized coal option. The PPBC option depicted here is higher in cost than the traditional pulverized coal unit; however, it is the least developed of the technologies shown and should benefit from continued research and demonstration.

![Figure 2.](image-url)

Peak and Intermediate Load Technologies

The representative peak and intermediate load technologies are compared in Figure 4. It can be seen that the combined cycle plant offers a significant increase in efficiency for a relatively small increase in the annual cost of capacity. The conventional gas or oil-fired steam boiler does not compare favorably with the combined cycle plant.

Staged IGCC

One option, or sequence of options, that has been receiving a great deal of attention is the staged installation of IGCC. As previously discussed, this offers the flexibility of incremental capacity additions and short lead times in addition to extremely low emissions when burning coal. The screening curves for the combustion turbine, combined cycle, and IGCC phases are shown in Figure 5. These curves indicate that the combined cycle option should be used for duties requiring a capacity factor of between about 15-65 percent, while the combustion turbine should be used for...
lower capacity factors; the IGCC plant should be used for higher capacity factors. This phased approach yields costs that are lower than any of the other technologies discussed here.

**Nontraditional Supply Technologies**

Numerous nontraditional supply options are available for planners to consider. Many, such as wind, hydro, and photovoltaic, are very site specific. Although these have not been included in this comparative analysis, there may be sufficient wind, water, and solar resources in some areas of the country to allow serious consideration. Two nontraditional supply options discussed here are solid waste incineration and cogeneration.

**Solid Waste Incineration**

The incineration of solid waste is a means of reducing the volume of waste to be disposed in landfills. The consequent generation and sale of energy is a means of reducing the cost of this option. The economic viability of incineration is, therefore, primarily associated with the cost of waste disposal and only secondarily associated with the cost of supplying energy. The development of waste-to-energy plants in the United States has been concentrated in areas of high population density, high water tables, and high energy costs, namely, the in northeast and southeast.

A unique feature of a waste-to-energy plant is that it has a negative fuel cost. These plants charge a "tipping fee" for each ton or cubic yard of waste (that is "fuel") brought to it for disposal. This negative fuel cost produces the negatively sloped screening curves shown in Figure 6. It is readily apparent that the economics of a waste-to-energy plant are contingent upon securing a sufficient quantity of waste to permit operation at high capacity factors. Figure 6 also demonstrates how tipping fees of $30/ton or more can make incineration a viable alternative to new coal capacity. It should be noted, however, that tipping fees in many areas of the country are presently below $20/ton.

**Cogeneration**

Of the many types and sizes of cogeneration technologies available, two were selected for comparison: natural gas fired 500 kw
and 200 kw engine/generators with waste heat recovery. The economics of cogeneration are affected by the match of thermal and electrical loads and the value of the generated electric power. These technologies are analyzed from the perspective of the electric utility system, not taking into account the potential benefit to the third party owner of such a system.

To permit a comparison to other electric supply options, the cogeneration analysis assumes that recovered heat is credited at the same cost as that of the fuel. Savings associated with cogeneration are credited to the electrical generation costs. It is assumed that the cogeneration is an add-on installation, and thus no credit for avoided heating plant is provided. Even in the optimum situation (100 percent of the thermal energy recovered is used), the cogeneration options in Figure 7 are still more costly than the new coal unit option. Having a poor match between electrical and heat loads results in lesser amounts of thermal use and, consequently, poorer economics, as shown in Figure 8.

Although the cogeneration technologies depicted here are more costly than a conventional coal power plant, they may be economically attractive to the cogeneration user. This is because the rate structure of some utilities results in a savings to cogenerators that only generate electric power to displace their own electric requirements. There may be marked regional differences which affect the attractiveness of cogeneration. For example, Figure 9 demonstrates that small cogeneration may be a cost-effective way for customers to avoid the relatively high electrical rates of the Southern California Edison Company, while the same cogeneration option does not look attractive on the Wisconsin Electric Power Company system. The data for Figure 9 use published rates in effect in fall 1986 and assume that displaced energy is evenly distributed over on- and off-peak and summer and winter periods.

Summary

The concept of central station generation is changing in view of lower load growth projections and increased uncertainty. Future supply technologies will need to be sized to better match load
growth, have shorter lead times, and require smaller increments in investment than the large central station generation facilities installed in the recent past. Several promising supply technologies are either currently available to utilities or are likely to be available in the near future. The selection of future utility supply options, however, must be made within the context of an integrated least-cost analysis that also includes renovation of existing plants, nontraditional supply options, and demand-side options. The best mix will depend on the individual circumstances of each utility. Even within such a mix, the utility supply technologies will be the standard against which alternative options are measured. As such, developments in central station generation technology will continue to play a key role in the ability of electric utilities to compete successfully in the future.
Implementing Avoided Cost Pricing for Alternative Electricity Generators in California

William R. Ahern

During the 1970s the electric utilities lost a great deal of political influence and credibility. Huge cost overruns with nuclear power plants destroyed confidence in their building programs. Gross overestimates of electricity demand growth, after prices had skyrocketed, undermined confidence in their planning. Customers in California were angry at the price increases caused by the increase in fuel oil costs initiated by OPEC. Utility engineering departments focused on large central station nuclear and coal plants with long lead times to completion, while high inflation rates in the late 1970s made such projects more and more expensive. It was a ripe climate for the growth of alternate concept of how the electric utilities should provide electricity generation.

Four concepts joined forces to attack utility market share for electricity generation. First, the “soft” technology advocates favored small-scale, renewable, diverse technologies such as wind and solar power, geothermal, small-scale hydro, and use of such fuels as agricultural and municipal wastes. Second, the economists favored the use of “market pricing signals” to develop generation instead of utility planning processes. This was to “maximize economic efficiency.” Third, engineering efficiency advocates favored cogeneration, the production of electricity along with existing uses of steam for such industrial processes as oil refining and food processing. This cogeneration obtains more useful work from the same amount of fuel energy. Last, those concerned with national security advocated reducing reliance on oil, to weaken OPEC and reduce its embargo leverage on the United States.

In California, these themes emerged in the first policy report of the new California Energy Commission in 1977. At the California Public Utilities Commission (CPUC), the economic efficiency arguments first emerged in rate design based on marginal cost for electric utilities. But at first the thrust was to try to convince the utilities to pursue renewable technologies and cogeneration through jawboning and setting goals. In 1978 the CPUC penalized Pacific Gas and Electric for failing to sign “enough” cogeneration projects. Rapidly it became clear both in California and in the “moral equivalent of war” Carter administration that electricity generation planning and pricing required a new framework, embodied in the federal Public Utility Regulatory Policy Act (PURPA) of 1978 and implementing Federal Energy Regulatory Commission (FERC) rules and CPUC decisions.

Basic Principles
The California PURPA program to encourage alternate generation has rested on the basic principle that the utility customers should be indifferent to whether their electricity generation comes from utility projects or from third party power producers. To encourage the latter, the FERC and the CPUC required that the prices utilities had to pay would be equal to the utilities’ own full avoided cost, the exact cost the utilities avoid when they purchase power from a third party power producer. This will be explained later. Second, the CPUC itself crafted standard offers or standard contracts with all the main contractual terms between the utilities and the third party power producers. A third party could simply sign the standard offer, with price and terms set by the CPUC, so the utility could not use its monopoly power to bargain the third party down in price or impose onerous conditions. Third, both federal and state law permitted only designated favored “renewable” technologies to come under the program: wind, solar,
hydro, biomass, geothermal, and waste-to-energy plants of less than 80 megawatts in generating capacity, but also cogeneration projects without any size limit. PURPA allows utilities to own up to 50 percent of a “third party” project, one of many compromises in the law, this one adopted at utility insistence.

Avoided Costs

Many states simply told their electric utilities to implement PURPA and negotiate avoided cost contracts. But the CPUC was determined to design the program, in detail, through rulemaking and hearings involving utilities and potential third party producers and then to promulgate the program, in detail, for unavoidable implementation by the utilities. The utilities were not trusted, at all.

Determining real utility avoided costs is difficult, but conceptually it is simple. If the utility buys one kilowatt-hour (kwh) of electricity from a third party producer, and cuts back generating at a power plant that uses 10,000 BTUs of fuel energy to generate one kwh, then the utility avoids the cost of 10,000 BTUs of fuel. If the fuel saved is gas costing 3¢/a therm (100,000 BTUs), then the utility avoids paying 3¢ to generate that kwh, and the short-run avoided energy cost is 3¢/kwh. That is the energy value of the third party’s kwh, or the short-run avoided energy cost that then becomes the energy price. The CPUC then requires the utility to pay 3¢ per kwh.

The third party power producer also provides a capacity value to the utility customers in that the kilowatt (kw) of generating capacity now under contract reduces the probability of electricity shortages. The CPUC values that kw of capacity at the cost of what the utility would have to build if it became short of generating capacity. The CPUC uses the annual rental cost of a combustion turbine to set this value, and it requires utilities to pay that value, the capacity avoided cost, to third party power producers who generate at least 80 percent of the time during summer peak demand hours. The capacity payment can look like this:

\[
\text{\$140/kw/yr. turbine cost } = 14,000 \times 8.\%
\times 24 \text{ hrs./day } \times 365 \text{ days/yr. } = 7,008 \text{ hrs.}
\]

\[
14,000 \times 8.\% = 2\% \text{ per kwh.}
\]

Thus, the short-run full avoided cost payment is:

\[
3\% \text{ avoided energy cost}
+ 2\% \text{ value of capacity}

5\% \text{/kwh avoided cost payment for one kwh.}
\]

This price is calculated for different times of the year, with different efficiencies (incremental heat rates) of power plants operating at the margin, and for different times of day, for each utility, and revised for changes in fuel prices three or four times a year. The CPUC forecasts incremental heat rates in general rate cases and then revises the short-run avoided energy cost payments for differing fuel cost forecasts.

Determining long-run avoided costs is much more difficult. This will be discussed later. Note that short-run avoided cost payments do not give third party power producers a chance to avoid new utility power plants. The cost of the utility plant is not avoidable in the short run, so plant capital costs are not included in short-run avoided cost payments.

Implementation Experience

Short-Run Offers

The third party power program in California has been continuously evolving, but by 1982 the short-run offers were mostly in place. These included all major contract terms, short-run avoided costs calculated as shown, which varied with forecast incremental heat rates and fuel prices, plus capacity payment tables. A third party whose project qualified under PURPA (technology and size) and who received a qualified facility (QF) certification from the FERC could simply walk into a utility office, sign the standard offer, and get paid accordingly. The utility had no say in the matter. The QF and utility might negotiate a nonstandard contract, with some special terms, but the QF could bargain from the position that, if need be, he could sign the standard offer at any time.

The QF could sign a contract for up to 30 years to provide power. The capacity payment tables provided levelized payments to encourage the industry to give QFs higher payments in early years of operation. The QF could commit to being available more than 80 percent of summer peak hours and receive the fixed capacity payments. This was Standard Offer #2, which provided for
levelized fixed firm capacity payments, based on the combustion
turbine proxy, for up to 30 years.

If the QF was a wind, solar, or hydro project, its availabil-
ity depended on the resource, so such projects could sign an "as
available" capacity Standard Offer #1 contract and be paid the
capacity payment in $/kwh. No generation, no capacity payment.
During 1981 and 1982, as oil and gas prices went to high levels
after the Iran-Iraq War started, it seemed that the short- run offer
would encourage widespread development of QFs in California. By
the end of 1982, 1511 megawatts (Mw) of QF capacity had signed
contracts (see Figure 1), a small but growing proportion of the
state’s more than 40,000 Mw of capacity. The CPUC regarded the
QF industry as an infant industry needing encouragement.
The main underlying assumptions of the program were appar-
etly validated as nuclear plant costs entered hyperspace and oil
prices climbed to $40 a barrel.

But two unforeseen events nearly throttled the third party
power program in early childhood: the drop in oil prices and trans-
mission line constraints.

The Negotiated Long-Run Offer

As 1983 began, world oil prices started to fall from the panic
peaks as OPEC’s share of world production fell, other production
increased, oil users moved to replacements, and conservation ef-
facts grew. The prices based on short-run avoided energy cost fell
from a peak of about 7$+/kwh to 5$ and then lower. Potential QFs
faced substantial uncertainty about what they would be paid and
what their cash flow would be. Potential investors and lenders be-
came sceptical. The conventional assumption of always increasing
oil and gas prices and, hence, short-run energy payments evapo-
rated. The CPUC recognized that if the industry were to grow in
an orderly fashion, there would have to be some price certainty
for QFs to enable them to obtain financial backing. Development
of a long-run price offer, however, while always intended, took a
back seat because it was not clear methodologically how to do it.
A long-run offer that would guarantee fixed prices for QFs be-
came imperative if the industry were to survive, however, and the
CPUC told the utilities, potential QFs, and staff to try to nego-
tiate such an offer. The utilities were willing because both QFs and
the commission were pressuring them to negotiate in “good faith”
fixed price, long-run contracts, but the utilities had no standard in
effect to assure them they would receive all their payments when
the nonstandard contract power showed up at the CPUC in their
fuel and power cost reasonableness reviews.
The intense four-week negotiations were highly successful. In
September 1983 the CPUC ratified the agreement, which provided
a Standard Offer #4 with these features. (1) In addition to up to
30 years of fixed capacity payments already available under Offer
2, a QF could be paid fixed energy payments, as forecast, for ten
years. Thus, for PG&E, the energy payment forecast was 5.55$ in
1985, 7.84$ in 1990, and 11.39$ in 1995. As with all the offers,
the QF had to be in operation within five years after signing a con-
tact. (2) After the ten years of fixed energy payments, the QF
prices go on to the then current short-run offer. (3) The QF
could receive levelized energy payments, but bonding was needed
to assure repayment of early overpayments. (4) Cogenerators could
not receive the fixed energy payments (because their costs vary
with oil prices too much and they might default if tied to fixed
prices) but instead could rely on payments based on ten years of
fixed forecast incremental energy rates, so their main risk would
be utility fuel prices. The new negotiated interim long-run price offer went into ef-
fact while the CPUC promised to adopt a final long-run offer
method, with fixed prices, based on full hearings, within a year.
The interim offer was to expire in a year. The QF industry gen-
erally complained that the CPUC staff and the utilities had been
too tough and that the fixed prices were too low to attract much
QF interest. This did not turn out to be the case.

Transmission Line Constraints

A QF could sign a standard offer but still needed to get his
power to the utility system. Then the utility would have to be
able to carry it to market. PG&E in 1983 concluded that it had
transmission line constraints on much of its system and that QFs
would have to pay the other, hundreds of millions of dollars to
upgrade and expand transmission line capacity to handle new QF
projects. Worse, PG&E could not tell QFs, when they signed con-
tacts, how much they would have to pay. This chilled the industry
and resulted in a special CPUC proceeding to assess the problem
and develop solutions.
Implementing Avoided Cost Pricing

To simplify substantially, the CPUC determined there was about 1,000 Mw of transmission capacity available for QFs without cost, but that above that amount added costs would be incurred on the northern part of PG&E's system. The "free" capacity would go to QFs on a "first come, first served" basis, depending on when a contract was executed. The dangling of this free good caused a rush to sign contracts, and a waiting list expanded of potential QFs with signed contracts but no transmission line capacity. The CPUC then found it necessary to promulgate a queue management procedure called the QF Milestone Procedure (QFMP). If a QF project failed to show, for example, site control, or failed to obtain the critical path permit by the time stated at contract signing, that QF lost its place in line, and others moved up.

Explosion

By the end of 1984, more than 10,000 Mw of QF capacity had signed contracts, by the end of 1985 more than 15,000 Mw, with nearly 3,000 Mw on line and operating (Figure 1). What happened? How did an "infant industry" struggling under low prices and transmission constraints sprint into an uncontrolled monster? The PG&E transmission line constraint situation prompted potential QFs to accelerate signing contracts, even though there were no constraint problems in the southern part of the state or with Edison and San Diego Gas and Electric, and even though the CPUC determined that QFs had to pay for transmission only if it was built solely for them and for no other purpose.

Also, after the long-run price offer came out, corporate America was cranking up. With ten years of fixed prices, treasurers could forecast cash flow. The studies in-house and by banks and investment houses took a number of months, but by late 1984 QF projects for California were on drawing boards and in financial packages all over the world. At the same time, oil prices were continuing down instead of going back up, as had been assumed in constructing the interim long-run fixed price. So the interim price offer started looking better and better. In addition, budget problems made it clear that special tax credits for renewable energy projects would not last much longer. All these factors prompted a "gold rush." Potential QFs decided not to wait for the CPUC to adopt a final long-run price offer. The proceeding was bogged down. The price was likely to be lower, much lower than the interim one. Potential QFs started to sign up for Standard Offer #4 in accelerating amounts.

On top of these events, cogeneration technology was becoming more efficient and less costly. General Electric, for example, and other turbine manufacturers started to drum up business, as did investment houses, formulating engineering and financial packages to entice industrial firms to develop QF projects.

Then a massive new cogeneration market appeared, the enhanced oil recovery market. Oil companies use huge amounts of steam in California's San Joaquin Valley and elsewhere to coax heavy oil out of the ground. They could use natural gas instead of their own oil, attach a turbine to the steam generation, and become cogenerator QFs. By September 1984 runnings of 3,000 Mw of oil recovery cogeneration on the doorstep plus accelerated sign-ups of Offer #4 were reaching the CPUC. Only the prior month, there seemed such a low level of interest in Offer #4 that the CPUC extended it indefinitely, without limit, until the final offer might be put in place. There had seemed to be no problem. One had expected more than 1,000 Mw to sign the interim long-run offer.
Crisis—Suspensions

PG&E showed 1,800 Mw had suddenly signed the fixed price offer that was now “too high” and provided information about the potential oil recovery market QFs coming in momentarily. The newly created CPUC public staff felt that to minimize ratepayers’ risk of overpayments, the CPUC should suspend interim Offer #4 right away. Legal advice at the time was, however, that staff would have to formally petition the commission to suspend, and that the commission would have to hold a hearing before it could take action (in later similar situations, revised legal advice was that the commission could take immediate action, call it interim, then hold a hearing, and then make the action permanent). So the staff served a suspension petition on all the parties and the commission scheduled a hearing. Only staff and PG&E supported the suspension. The commission was urged by a wide variety of parties not to take “precipitous” action. Even the representative from the City of San Francisco, usually a vigorous consumer advocate, urged the commission to leave the long-run price offer in place. San Francisco was then pursuing a waste-to-energy project that needed the price to be economic.

The commission suspended the offer only for cogenerators addressing the oil recovery market risk, larger than 50 Mw in size, but was convinced that added action was needed. It was very difficult to shift rapidly from encouraging an infant industry to controlling a gigantic one. Not until April 1985 was the “too high” long-run price offer suspended for all QFs, and by then 11,000 Mw had signed up.

All the projects that were being formulated came in, from Luz solar parabolic dishes to Ultrasystems wood chip burning plants. The infant industry grew up overnight. As more QFs signed up, it became clear the capacity payments under Offer #2 were too high, because new capacity was not needed for many years. That offer was suspended in spring 1986. We are now taking stock of what happened and trying to manage the aftermath. The CPUC must figure out what to do with “pioneers” (QFs who signed early short-run energy price contracts and were not allowed to switch to the interim long-run offer but were supposed to wait for the final offer) and “orphans” (projects caught by the suspensions in midstream), as well as pressures on the utilities and commission to allow high prices for “deserving” projects, such as municipal waste-to-energy projects, through negotiated nonstandard contracts.

Lessons

One can regard this story as either a mess that will burden utility customers with extra costs (favored by utilities attacking the program) or as an exciting success and learning experience enabling third party power to be placed on a solid long-term footing (favored by CPUC staff and QFs). What have we learned?

Control the Program. For any energy or capacity price, put a limit on the amount of QF power that can come in under those prices. The limit can be in terms of percentage of utility generating capacity or in blocks of megawatts.

Control Entry. Require tokens of seriousness before allowing the signing of a contract, tokens such as site control or project design or earnest money; then require tokens of progress, such as financing and equipment ordering and start of construction, to assure projects are real and to prevent speculation.

Assign Transmission Capacity and Costs. Develop transmission access and cost guidelines ahead of time, so the signing of a QF contract can include the specifics on cost responsibility for transmission.

Use Nimble Procedures and Minimize Risk on Customers. A regulatory commission, designed to deliberate on utility proposals, must be able to change aspects of the program rapidly and sometimes in secret (prospectively, not retroactively) if circumstances place too much risk on utility customers. Close monitoring is needed.

These four lessons are important. Implementing them requires substantial commission and staff attention.

The Future: Mature Program, Mature Industry

The Problem

Those who simply do not like the third party power program and want to put electricity generation completely back with the utilities portray what has happened in California as a big mistake (for example, James Cook, “Cogeneration Gap,” Forbes, November 3, 1986, pp. 70-73). But “the problem” cannot be defined
Implementing Avoided Cost Pricing

until we know exactly how many of the QF contracts actually materialize as operating projects. Our estimates are that 30-60 percent of the 15,000 Mw will actually come on line, because some projects will definitely meet financial, engineering, and regulatory constraints. The California Energy Commission must approve as "needed" each thermal project larger than 50 Mw in size.

That commission has required some large cogeneration projects to renegotiate contracts with the utilities to obtain approval. More than one-third of the contract megawatts represent wind, hydro, and solar projects, which can generate electricity only during limited hours of the year (Figure 2).

Adverse costs to ratepayers are further mitigated due to the fact that cogenerator prices are not fixed, but vary with utility fuel costs. So those prices under Offer #4 have come down substantially. Cogeneration is nearly one-half the megawatts, so "only" about 20-25 percent of the megawatts are the ten-year fixed price long-run contracts that are now "too high" in cost. And many of these will not survive air pollution permit and other requirements. Thus, the magnitude of the problem from the gold rush to Offer #4 is much smaller than the "problem" caused by cost overruns on nuclear plants.

The Future Long-Run Price Offer

Meanwhile, the CPUC has formulated the details of how to promulgate a long-run price offer for QFs so they can have the opportunity to avoid utility plants. The CPUC declared in its decision that the "QF industry is here to stay" (D. 86-07-004, p. 57). The major elements of the final long-run price offer are noted below.

1. Each utility develops a twelve-year resource plan and provides the costs of each planned generation addition.
2. Hearings are held on the plans.
3. The CPUC identifies cost-effective avoidable plants that are avoidable within an eight-year deferral window (throwing out any non-cost-effective additions).
4. Each utility puts out a QF price offer based on the fixed and variable costs of avoidable plants (fixed prices are good for not more than fifteen years).
5. Potential QFs submit their generating capacity and which plant they want to avoid, that is, which prices they will accept;

if not enough QFs sign up, all those that made submissions receive full price contracts.

6. Potential QFs also submit the percentage of the price they are willing to take. This is a bid to be used if too many QFs make submissions for the amount of available capacity; if there are too many subscribers, QFs with the lowest bids are taken, up to the amount of needed capacity; they are then given contracts at the price bid by the lowest bidding bidder (a second price auction—in effect the winning bidders get a price based on the next higher cost project the utility "avoids" taking).

7. The CPUC updates the plans and avoidable plants and price offers every two years.

8. If a QF comes on line prior to the planned start date of the avoided utility resource, the QF receives only short-run energy payments until the start date.
Implementing Avoided Cost Pricing

The long-run price based on an avoidable plant has three parts: the capacity payment, the energy payment, and the energy related capital cost payment. For example, a planned avoidable geothermal plant has a capital cost of $136/kwh in 1995 and steam cost of 76¢, for a total cost of 206¢/kwh. The QF will receive a capacity payment as calculated under the short-run offers, say, 56¢/kwh in 1995 (or $350/kw/yr). The QF avoids the steam cost of 76¢. Then the capacity value of 56¢ is subtracted from the 136¢ capital cost to obtain an 80¢/kwh “energy related capital cost.” It represents fixed costs, but the QF receives an “energy” payment of 76¢ + 80¢ or 156¢ per kwh provided in 1995. Thus, the new final long-run QF pricing procedure incorporates the lessons learned from the interim offer experience. All QFs must meet the QF Milestone Procedure, and entry is limited to the amount of QF capacity defined by specific identified avoidable utility resources.

Adders

The standard offers permit utilities to buy QF power at all times it is made available to them, except for limited hours during which the utilities can curtail QFs when less costly resources are available (for example, 300 hours/yr. in interim Offer #4). Thus, QFs on standard firm capacity contracts are base load providers. However, generally only 40 percent of utility generation needs are base load, while 40 percent are intermediate, and 20 percent are peaking resources that are dispatched on and off as demand changes. The CPUC wants utilities to provide “adders” to QF prices in return for more QF dispatchability, or curtailment, or other features that can help the QF complement the utility system and avoid intermediate load type plants. The CPUC asked for more negotiations and for QF consortia to look at ways of being more valuable to the system. This is necessary if QFs are to be able to compete for intermediate load capacity growth in the future.

More Lessons

Commission Burden

As you can see, the regulatory commission is required to ratify and cost out a utility generation resource plan, taking on that responsibility and setting long-run prices that can be in effect for fifteen years. As we have seen, these plans and prices can be “wrong,” and in fact just about all long-run forecasts turn out to be high or low. Setting a long-run price offer is equivalent to building the plants that were avoided, although the construction and operating risks are on the QFs and not on utility customers. A commission needs capable resource planners, system models, and other resources to implement this program with some confidence.

QF Interest Group

When the QF industry grows it can become an influential interest group, with interests in high utility avoided costs and higher ratepayer payments for electricity. Not only is this a new group to pressure the commission, but also it can work for the state legislature to obtain protection and favored treatment. In California the QF industry has obtained a law allowing cogenerators to sell power to up to two adjacent customers without being regulated, and another law requires the CPUC to set natural gas rates to cogenerators at the same price as to the electric utilities.

Utility Shares of QFs

The utilities can own up to 50 percent of QF projects. This can be troublesome not only because of the possibility of self-dealing with nonstandard contracts but also because it gives the utility, or its holding company, a stake in higher avoided cost forecasts and prices. The best protection for ratepayers would have resulted if utilities were allowed only to be on the purchasing side of the QF program. Instead, the commission and staff take on more of a burden both in checking arrangements between utilities and QF affiliates and in defining a reasonable resource plan.

The Value of the Avoided Cost Exercise

Determining each utility’s short- and long-run avoided costs on a regular basis lets QFs take on the risks and compete with utility plans and the most cost-effective plants the utilities can build. This competition seems healthy. The avoided cost forecasts also serve as clear “common yardstick” benchmarks for evaluating a range of utility projects and programs. It might seem incredible that a utility would pursue a project costing more than its own avoided cost, but Southern California Edison submitted a brine geothermal project near Heber that the commission had to deny, and PG&E submitted a power purchase contract with the Kings
River Conservation District for power from a 120 Mw dam at Dinkey Creek that the commission had to dismiss. It is clear the avoided cost exercise, with forecasts and QF attention and competition, is healthy discipline for utilities and helpful protection for ratepayers. Utilities still have many reasons to pursue costly projects, so a comprehensive and public forecasting of their least-cost resource plan options provides an effective system of checks on utility planning. If they find low cost projects that QFs cannot beat, they should build them (being kept to the cost estimates through caps or pricing based on avoided cost performance). If utilities want to keep part of the generation market, they will have to develop low cost options.

Conclusions

Research and Development

PURPA has let loose massive experimentation in the United States with electricity generation. In California the landscape is covered with windmills and small hydro plants, woodchip collectors, and brine geothermal plants. Many of these experiments may now be more relevant for the early 2000s than the late 1980s, given the drop in oil and gas prices, but there has been a ferment of R&D activity, with the developers taking the risks. Putting out a price for the long run seems a desirable way to stimulate research and development on the next economic sources of electricity generation. It seems far preferable to massive federal investments in projects like the Clinch River Breeder Reactor. It may even be preferable to the R & D conducted by unwieldy consortia of EPRI, engineering firms, and utilities. The favored technologies and 80 Mw limit in PURPA should be eliminated so QFs can be coal gasification plants or combined cycle gas plants. The assumption underlying those PURPA restrictions seems to have gone.

Commission—Utility Role

It is easy to let the utilities run this program. Let them negotiate. There is the risk utility management may be wrong, but the regulatory commission is not implicated and can, in fact, second guess utility management and protect ratepayers. It is much more difficult to take an active role in generation planning, costing, and pricing. But even though no new nuclear plants have been ordered since 1979, we hear talk of “safe, modular” nuclear reactors and of regional FERC regulated generation. Some utilities are trying to end this QF program, while others see benefits for subsidiaries in owning shares of unregulated (profit, not price) QFs. In California the QF program seems here to stay, and we hope the maturity will be more peaceful than the adolescence.
Comments

Matthew I. Kahal

In 1980 the Federal Energy Regulatory Commission (FERC) issued its rules implementing Section 210 of the Public Utility Regulatory Policies Act (PURPA), the rules governing cogeneration and small power production. The various states followed with their own implementations shortly thereafter. Thus we have had roughly five years’ experience with “PURPA 210,” and it is now time for an assessment.

We are fortunate to have three important points of view expressed so articulately. William Ahearn, from his position at the California commission, recounts his state’s unanticipated “gold rush” of QF development. This experience teaches us that without intelligent, skillful regulation it is possible for the situation to get out of hand to the detriment of the consumer. Those who believe that all trends in this country begin in California should pay close attention to his paper.

Janice Hamrin is clearly an advocate for the QF industry. There are two central themes to her paper. First, the “avoided cost” ratemaking framework, properly applied, will ensure fair treatment to all concerned as well as promote economic efficiency. Second, the development of QF power helps to insulate the consumer from the risks associated with utility supplied power.

The utility viewpoint is ably presented by David Porter, whose paper carries the provocative subtitle, “Can Utilities Compete Successfully?” His answer is “yes,” but not a simple yes. Load growth in the future can be cost-effectively served by new central station utility plants as long as utilities construct plants appropriate for their circumstances. His paper is a plea for a “level playing field” in which all meaningful options—demand-side, central station, and nonutility—would be judged according to the same economic criteria. He sees a role for all three types of resources, with utility planning integrating them together into a least-cost plan.

Background

Before considering the issues, it is useful to step back and consider the state of QF development. According to a recent survey by the North American Electric Reliability Council (NERC), approximately 8,000 Mw of cogeneration/small power production capacity is expected to be in service by 1986. This is slightly more than one percent of the roughly 700,000 Mw of installed capacity in the United States and Canada. The NERC survey indicates that nonutility power will increase to more than 25,000 Mw by the mid-1990s. While this is still only a very small fraction of total installed capacity (roughly 3 percent), it represents roughly 20 percent of the growth in installed capacity during this decade. As the utility industry moves gradually from a condition of excess capacity to a supply/demand resource balance, cogeneration and small power production will become a vital part of our resource base. Given the apparent reluctance of utilities to undertake major construction programs, the contribution of nonutility power is particularly important.

The NERC survey also reveals that cogeneration development tends to be highly regionalized. Nearly two-thirds of the estimated 25,000 Mw is expected to occur in two states—California and Texas. By 1995, cogeneration and small power production is expected to be 7.6 percent of total generating capacity in Texas and slightly more than 6 percent in California. In most other areas of
the country, cogeneration and small power is expected to account for one to three percent of installed capacity by the mid-1990s.

Given these patterns, I believe it is no coincidence that two of the three speakers in this session are from California. If the NERC survey is accurate, the California experience is not necessarily typical of what the rest of the country can expect over the next decade.

The Changing Economics of Power Supply

All three papers paid considerable attention to the application of "avoided costing" to the setting of buy-back rates for QFs. California regulators, as described by Ahearn, are attempting to use avoided costing within the context of long-range utility planning.

This is to be supplemented with concerns over controlling entry, transmission access, and other practical considerations. Porter explains that the costs of constructing and operating new central station plants will define the rates that cogenerators will be entitled to receive in the future. Hamrin clearly admires the avoided cost paradigm, and as an economist, I must do the same. Up to now, avoided costing, in theory and practice, has been a central focus of both FERC and state regulation of cogeneration rates.

Despite its strong theoretical foundations, I believe the avoided cost approach emerged from the utility cost relationships which existed at the time of PURPA and the promulgation of the FERC rules. For most utilities during that era, the marginal costs of power supply substantially exceeded average embedded cost. This was particularly true in California, where expensive oil and gas was at most times the margin fuel. High marginal costs meant that the economics of cogeneration would be very strong and the buy-back arrangement favorable.

After 1982 the gap between marginal and average cost on most utility systems gradually began to erode, and that trend has accelerated dramatically since 1985. This change is attributable both to a decline in marginal costs and increases in average cost. Marginal costs have fallen in accordance with the slide in oil and gas prices and on the capacity side due to sharply lower interest rates.

Ironically, as marginal costs have fallen, average costs (that is, electric rates) have generally been rising, reflecting expensive new plant additions. For example, in 1980 the average cost of residual oil at steam electric power plants was $4.27 per million

But compared to $2.13 by fall 1986. A dramatic decline in capital costs, which lowers avoided capacity costs, also occurred at this time. In contrast, the average industrial rate per kwh was 5.2 cents in late 1986 compared to 3.7 cents in 1980. This is a stunning reversal in cost relationships.

This reduction in avoided costs does not necessarily make cogeneration less attractive. Declining fuel prices (particularly natural gas) and lower capital costs will help cogenerators lower their costs of carrying and operating their facilities. However, the marginal cost/average cost reversal has a profound effect on the incentives faced by cogenerators. With low buy-back rates and high fuel rates, compared to earlier years, the cogenerator may now find it in his interest to "self-generate," or consume his own output, rather than sell all of it to the utility. In other words, for an industrial customer, the power is more valuable consumed on-site than sold to the utility. When this happens, the robust avoided-cost paradigm collapses, and the effect of cogeneration on the consumer becomes much less clear. At least in the near term, it is likely that consumers will be negatively affected by this form of "by-pass."

As this occurs, as it inevitably will in response to the new incentives, it raises new regulatory issues. Attention shifts from avoided costing methods to the proper pricing of back-up or supplemental power. The utility is required to provide this service, but excessive rates could be used to discourage self-generations arrangements or even the development of the facility itself.

The incentives faced by the utility are asymmetric. Utility commissions typically allow full recovery of QF costs through a fuel clause or similar automatic arrangement. However, lost revenue stemming from self-generation can only be recouped with some difficulty through a general rate case. In contrast to the harmony of the avoided cost rate framework, where in theory no party is adversely affected, this new reality suggests a potentially sharp conflict of interest between the QF and the utility.

The next step after self-generation is the possibility of a QF selling its excess power to other utility customers. This is just beginning to emerge as an issue, and a very threatening one to the utility. Ahearn mentions new legislation in California that would permit the QF to sell power to adjacent utility customers. If this emerges, then QFs will truly be viewed as a competitive threat.
A third issue likely to emerge is access to wheeling. Declines in avoided cost have sharpened the interest on the part of QFs to shop around for the best available deal. This cannot be done, however, without access to wheeling service. Undoubtedly, more will be heard on the wheeling issue, which is the subject of a FERC inquiry and possible congressional action.

Who Bears the Risk?

Despite its theoretical soundness, the avoided cost approach does not address the question of risk and its allocation. QF rate regulation has important implications for the risks borne by consumers, the QF, and the utility. Whereas avoided-costing application is mostly a technical problem, the allocation of risk involves the formulation of social judgments.

Hamrin forcefully argues that QF development helps insulate the consumer from risk in comparison with utility-supplied power. That conclusion, however, does not universally hold and ultimately depends upon the contract features and provisions approved by the regulators. For example, a long-range QF contract with fixed terms is really no different than any other “take-or-pay” contract that a utility enters into, with all the attendant risks for the consumer. Unquestionably, the amount of QF capacity likely to emerge is difficult to forecast and may lead to an excess capacity problem. Who should absorb the cost of the excess capacity? Unless QFs are willing to absorb that cost or forgo capacity payments, consumers do face an added risk. As I mentioned earlier, self-generation is a very real threat facing some utilities.

Yet, QF developers must finance their projects in “real world” capital markets. Requiring QFs to absorb all the risk would be biased and might choke off investment which would otherwise be justified by economic criteria. The allocations of risk among the QFs, consumers, and the utility is a judgment call that regulators must make in establishing procedures and contract terms. The marginal cost/average cost reversal that I discussed earlier only serves to heighten this concern.

Conclusion

As these papers reveal, there is ambivalence today concerning cogeneration and other types of nonutility power. I have heard this ambivalence expressed by both consumer advocates and utility executives. The PURPA 210 avoided cost paradigm is a well-conceived and highly regarded framework carefully designed to achieve both allocative efficiency and fairness. Yet, some unanticipated changes will create new regulatory issues. The “gold rush” phenomenon described by Ahearn has forced the California commission to consider control of entry and access to transmission in order to protect the public interest. Is this experience unique to California, or will it be repeated elsewhere?

The reversal of marginal cost/average (embedded) cost relationships has created new interest on the part of cogenerators in self-generation, or “by-pass” as it is sometimes called. When Porter asks whether utilities can compete, this is the real field of competition as far as the utility is concerned. Moreover, there is even the competitive threat of cogenerators serving other utility customers.

Finally, in the design of cogeneration long-term contracts or ratemaking arrangements, how should risk be allocated? There may be a trade-off between encouraging QF development and exposing utility customers to risk.

These problems are giving rise to new regulatory issues which will become increasingly apparent: standby or back-up rates for self-generators; special discounts or “economic development rates” for industrial customers to discourage self-generation; wheeling access for cogenerators; and regulation permitting QFs directly to serve other retail utility customers.

The purpose of my comments is to alert the reader to these emerging issues and the economic forces behind them. The positions that utilities and QFs will take on these matters is fairly clear; by and large they have competing interests. However, determining the broader public interest will be much less clear and undoubtedly the subject of much debate.

Notes

Part Seven

Bulk Power and
Other Electricity Issues
Antitrust Issues in Bulk Power Supply

James E. Meeks

In the late 1960s, when we first started addressing the application of antitrust concepts to the electric power industry, the primary focus was upon access to efficient and reliable bulk power by small systems, primarily publicly owned municipal systems and co-ops. That framework provided the Otter Tail case, which in a general way resolved much about the reach of the antitrust laws in this area.¹ It used the bottleneck theory in applying § 2 of the Sherman Act. That case, the Supreme Court’s decision shortly thereafter in Gulf States² and several lower court cases ushered in a new era at the FPC-FERC, the AEP-NRC, and the SEC.³ Each of these agencies, in granting regulatory approval within their jurisdictional ambit, came to apply antitrust ideas as part of the public interest standard. This combination of legal approaches in the courts and in the agencies accomplished much in forcing access for small systems. Meanwhile, as we all know, the economic factors in the industry started to change, and in many instances it was no longer a matter of forcing participation in large-scale projects upon the large integrated systems; they sought such participation
to spread the cost and risk of these enterprises. Also, many co-ops and municipals had found ways of pooling and embarking upon joint venture of their own. Thus the burning antitrust issues of the late 1960s and early 1970s, at least in general outline, became pretty well settled.

These cases and others make it clear that a violation of § 2 of the Sherman Act (and of § 1 as well, if a contract, combination, or conspiracy is involved) is made out in principle if the defendant system refuses to deal with an actual or potential competitor in order to deprive that competitor of access to efficient baseload, emergency, or peaking power or possibly economy energy. The general theme has been applied to refusals both to wheel and to allow reasonable participation in joint ventures and pooling.

To be more specific, Section 2 makes illegal an attempt to monopolize or the monopolization of a relevant market. The Supreme Court has said that the offense of monopoly under Section 2 of the Sherman Act has two elements: (1) possession of monopoly power in a relevant market and (2) willful acquisition or maintenance of that power as distinguished from growth or development as a consequence of a superior product, business acumen, or historic accident. 6

A violation thus requires determining a relevant market and whether the defendant in fact has monopoly power in that market. I will not go into detail on relevant markets, except to note there is some disagreement among the authorities about how to approach this issue in the electric power industry in various contexts. 6 For present purposes, however, the issue is a relatively easy one in my judgment. In a bottleneck, refusal to deal case, such as we are discussing, the defendant almost always has monopoly power over the transmission function, else the problem would not be posed.

The control over the bottleneck is enough to raise the question whether the monopoly power is being used to retain or achieve monopoly results at either the generation or local distribution level. This was the basic teaching of *Otter Tail.*

As a practical matter the test for relevant market power ought to be, if it is not, whether customers have a viable option to obtain necessary service elsewhere. Can they, for example, at a reasonable cost build their own generation capacity or, at reasonable cost, extend subtransmission lines relatively short distances and get access to the product from other sources? It was on this kind of showing that one recent case was lost when it was demonstrated that alternatives were economically available. 6 Nevertheless, that is rare. The transmission bottleneck usually is effectively controlled by the dominant private system in the area. Where that can be shown, it establishes the market power requisite for a Section 2 violation.

A Section 2 monopolization case also requires intent. But, again, under recent case law that is a fairly easy matter to resolve in terms of exclusionary—bottleneck—refusal to deal. Intent may be inferred from the mere refusal, at least when coupled with the absence of any apparent legitimate business explanation. This was the basis of the Supreme Court's affirmation of a jury verdict of a Section 2 violation in the recent *Aspen Ski* case. 7 There a dominant company, controlling three of four ski slopes around Aspen, Colorado, had for several years participated with its only competitor in a joint arrangement whereby a customer could buy a six-day ski pass good on any of the four slopes. The defendant pulled out of the arrangement, causing substantial loss of business to the competitor. Since there was no legitimate business explanation for the withdrawal and there was significant evidence that the purpose was to deprive the competitor of business, the Court affirmed the jury verdict.

*Aspen Ski* is the latest in a series tracing out Section 1 and Section 2 illegality in this kind of situation. 6 The § 2 violation is established where the defendant gains monopoly power through otherwise unjustified exclusionary conduct, where it uses its power in one market to gain an advantage in another, or, and most relevant perhaps here, where it uses exclusionary behavior, such as refusal to deal, to prevent a current or potential competitor from bidding away its existing business. The court in *Aspen Ski* and also in *Otter Tail* said that one in a monopoly position could not use exclusionary behavior to gain a competitive advantage in an attempt to gain or hold its customers. Legitimate competition, demanded by Section 2, requires that the firm hold its customers by offering better quality, better price, or both.

Of course, to make out the case there must be a reasonable request made and refused. One recent case failed because that basic prerequisite had not occurred. 6 If the refusal has occurred, however, and there is no reasonable alternative source, the controlling firm is using its bottleneck monopoly control over the transmis-
ction function in an exclusionary way, and the intent is clearly to hold on to existing or potential customers. That is illegal.

One defense is available under the cases, including Otter Tail itself. If there is a sound reason for the refusal unrelated to preventing competition, the inference of illegal intent may fail. Such a justification would be present in my view if the capacity in the transmission were inadequate or if there were technical problems involving reliability in the interconnections necessary to perform the service—such as load balancing or something of the kind. But that independent reason for the refusal may be hard to prove in the present context of most electric power exchanges, involving as they do complex interconnection and pooling. The problem is that the service is usually already being provided, or would be if service were requested, by the system refusing to deal. Assuming an interconnected transmission grid, that service will already be affecting the whole grid system in comparable manner no matter whether the service is being sold by the home territory system or by a distant system wheeling the power over the transmission grid. While it is impossible to trace the “contract path” of electricity, that is true irrespective of who is party to the transactions involved. Thus a technical inability to render service already being handled, or of new service that would be provided, will be hard to establish. Nevertheless, the technical problem involves in controlling the movement and effect of electric power on the system is so difficult to understand fully that it may be an issue with which the courts will have great trouble.

From this brief synopsis we see that the broad outline of the law as applied to the electric power industry is now relatively clear. What is difficult is applying those broad concepts to specific situations. The cases are not easily resolved, and in recent years the success rate of plaintiffs has not been very high.

In some cases juries have simply not been convinced that a violation of § 2 has been made out. This was the case, for example, in Cleveland Electric Illuminating.\(^\text{10}\) These kinds of cases are very hard for a jury to understand and also pose a special challenge to the judge in charging the jury. The jury decisions may also turn on rather peripheral matters and local prejudices.

The price squeeze cases have proven particularly difficult.\(^\text{11}\) The classic case is one in which it is alleged that the wholesale system is setting its wholesale price higher than it is selling to retail customers, for which it competes or potentially competes with its wholesale customer. Such retail customers are usually large load customers in areas where both systems can sell. A variation deals with the competition in ability to attract new customers to locate in one’s service area.

The difficulty with these cases grows out of the fact that the rates involved are closely regulated. This may be what makes predatory pricing attractive when it might not make sense in an unregulated market, but it also means that regulatory agencies are approving the rates in question, presumably using a public interest standard. Since the wholesale rate is regulated at the federal level and the retail rate at the state level, it is possible in theory, at least, to engage in price discrimination that would constitute predatory pricing and a Section 2 monopolization violation. But since the regulatory authorities are involved, it becomes very difficult to establish that any rate discrimination having the predatory effect was employed with intent to monopolize. It can usually be argued effectively that the differences in rates simply reflect differing rate treatment by the respective commissions, or timing of rate cases, or other forces outside the control of the firm.

Even when the plaintiff succeeds in surmounting these problems, as in Mishawaka,\(^\text{12}\) probably the leading case in exploring this area, it is very difficult to come up with a remedy that makes sense. In Mishawaka the court held the plaintiff to a relatively stiff requirement of showing lost business in order to make out damages. Damages of that sort are hard to prove. The courts cannot order changes in the rates themselves, since that is the responsibility of the regulatory authorities. That point was reemphasized recently in another context by the Supreme Court in Square D.\(^\text{13}\)

This leaves the court, even if it finds a price squeeze violation, with little more than the power to slap the wrist of the violating system.

Thus, in the mid-1980s we find the law on access at the wholesale level relatively clear. The recent cases have been dealing with detailed implementation of those general rules. But the next chapter is about to be written, and it will involve the retail market, at least, for large load customers, as well as the wholesale market.

The new situation grows out of the very significant current excess generating capacity. For a variety of reasons on both the demand and supply sides of the equation, that excess capacity may
be with us for some time, in my judgment, despite predictions that we will soon be back in a shortage situation.

Moreover, the action of regulatory commissions in refusing to include all the new capacity in ratebase has provided enormous pressure to sell the power in alternative, off-system markets. Significantly, in addition to the market for wholesale loads, there is the potential to sell blocks of this excess power to large industrial customers in distant territories if transmission capability can be found and if state law permits such sales. Thus the potential for significant retail competition for such loads is present. Under these new marketing circumstances, will a refusal to wheel the power at the request of another system to service a retail customer in one's own territory be a violation of Section 2 of the Sherman Act? Certainly as regards a potential wholesale customer, Otter Tail and its progeny seem to say yes, at least where there is effective control of the transmission capability. Will the courts reach the same result with regard to a retail customer?

Presently pending in the federal court in the Middle District of Louisiana is a case entitled Gulf States Utilities Co. v. City of Lafayette,13 which poses the troublesome questions. (Incidentally, the case has now been sitting there for about two years. Gulf States appears preoccupied with other problems for the moment.) Stauffer Chemical company was a very large retail industrial customer of Gulf States. Upon expiration of its supply contract a couple of years ago, it announced that it would have to have much cheaper service or would be forced to close or move the plant. It then negotiated with the City of Plaquemine, some seven miles distance but without direct delivery capability, to buy power from the city system at cheaper rates. Plaquemine in turn contracted to get the power from the City of Lafayette, which had substantial excess generating capacity to sell. The whole arrangement, however, was dependent upon Gulf States agreeing to wheel the power and to lease its substation located at the Stauffer plant. Gulf States recognized its antitrust vulnerability if it simply refused to wheel. Instead, it filed a declaratory judgment action in federal court asking, among other things, whether the refusal to wheel would be a violation of Section 2. (As an aside, I have to admire the strategy. Gulf States has been able to frame the case and the issues raised in about as positive a way as possible from its point of view.) As I said, the case is still pending and Gulf States is wheeling the power under a temporary injunction and pursuant to a wheeling tariff filed with the Louisiana Public Utilities Commission. The case demonstrates dramatically the issues now facing the electric power industry. It not only poses the antitrust issue in the retail setting but also poses some interesting and difficult questions about federal-state jurisdiction.

A brief review of the earlier discussion of Section 2 as applied to the wholesale market suggests there is no obvious reason not to apply the same rule of competition for service to large retail customers, using the subtransmission system like a common or contract carrier to get the power service to the customer. If this scenario sounds a little familiar, it is quite similar to what is presently happening in the gas industry, and perhaps telephone as well, with the bypass options developing in those industries.

The critical question is: If the antitrust laws are used to force development of a partially competitive market in electric power at the retail level, what effect will that have upon the industry and its regulation?

In a normal market, one would expect the willing buyer and seller to strike a mutually beneficial deal at or near the producing firm's short-run marginal cost. In our electric power industry setting, however, allowing the competitive market to work like this challenges the very foundations of our historic public utility regulatory approach. Among those fundamental ideas are allowing recovery of fully embedded costs, guaranteed service availability and reliability, and elements of cross-subsidization of some service. The regulatory commissions, especially at the state level, are going to have to decide whether to accommodate these changes that will accompany development of competitive markets. Of course, those forces may in fact be too strong to avoid. The market may dictate the policy.

A choice to adapt regulation at the state level to the introduction, promotion, and protection of competitive markets may be the wise policy decision. It may even be required by the antitrust laws, but I think it probably is not. From an antitrust point of view, the policy choice probably still lies to a large extent with the states. While federal regulatory policies may in some circumstances preempt state regulatory choices, that is not generally the case with the antitrust laws. Thus the state commissions may be able to opt against increase in competitive activity and, in the
process, protect the firms from antitrust exposure by carefully shielding them under the state action doctrine.

That doctrine grows out of a 1943 case, *Parker v. Brown*, and under certain circumstances shields from the antitrust laws private action if it is conducted pursuant to a clearly articulated state policy substituting regulatory control for competition. *Parker* held that Congress did not intend in the antitrust laws to preempt generally state regulatory control over business behavior. It is important to note, however, that the Supreme Court has also held that the electric power industry enjoys no general exemption from the antitrust laws. Even so, the state action doctrine can be used to immunize behavior that otherwise would violate the antitrust law. The exact parameters involve a complex federalism issue beyond the scope of this paper, and on the margin the doctrine is particularly difficult to work with. But as applied to comprehensive state regulation of traditional public utility matters, such as we are involved with here, there is little in the cases to suggest that antitrust immunity will not be accorded to the parties if they are following a clear state policy that substitutes regulation for competition. This is the message I take from several recent Supreme Court cases.

However, to assure success in bringing the doctrine into play, the state must adopt a conscious, fully articulated policy of supplanting competition with regulation, clearly mandating to the utilities firms what is permissible conduct consistent with that policy and carefully monitoring their compliance. In the present context that means the state regulatory authorities must choose the policy of exclusion and approve the exclusionary refusal to deal practices that would otherwise trigger the Section 2 monopolization charge.

Let us return to the market context and look more carefully at a situation such as the Gulf States episode referred to earlier. Three distinct possible approaches for handling the potential competitive challenge are possible. Approach #1: The fully integrated, full service firm currently serving that territory could provide the transport function, losing the sale at full price, but charging a reasonable price for the transport activity, that is, unbundling the service. Approach #2: It could refuse to render the transport service, and the customers will either have to buy from it or not buy, turning to some other option. Obviously, this approach poses the possible Sherman Act Section 2 violation for the firm unless it is clearly protected by the state action doctrine. Approach #3: The home territory company can meet the price of the distant seller and render the same service itself but at a much reduced price over what it would otherwise charge.

The obvious consequence in the first and third approach is that the home territory firm will lose a major source of income out of which to cover its fully embedded costs. The firm will be forced to recover more of these from other customers, those not able to turn to other options. Alternatively, if price discrimination is not permitted and the benefits of competition are forced through to all customers, investors in the firm will have to absorb the failure to recover those embedded costs. In a freely competitive market, the latter is what would happen as price to all customers is bid down to short-run marginal cost until the excess capacity was absorbed. There are those who argue that is precisely what we should allow to happen now in the electric power industry. Some would even say it is inevitable. Regulatory or legislative bodies at either the federal or state level or possibly both will, have to decide which route to follow.

There may be some situations in which, because of the interstate aspect of the transmission function, the states may be preempted from effective control. The jurisdictional division as applied to this kind of mixed retail/wholesale market for power moving, essentially on an interstate transmission network, is not at all clear under current law. I do not intend to address this jurisdictional issue here, but it is important.

Ignoring that possible preemption issue, regulatory action at the state level could frequently block development of the competitive market transactions if the commission makes the basic policy decision to do so. Enforcement of stringent territorial exclusivity rules, especially as applied to end-users, or tight control over prices where the state commission has jurisdiction, or even control over use of the local distribution system for wheeling or transportation may be used to prevent, or at least discourage, free market retail transactions. This restrictive approach has the obvious advantage of maintaining the present ability to spread the firm’s recovery of fully embedded cost over all system customers. However, it has the disadvantages of wasting excess, idle supply capacity that could be productively used to satisfy consumer needs. Moreover, as we have learned in recent years, demand is elastic for these services. The
potential purchasing end-users may be able to turn to alternate energy sources, alter processes to reduce reliance on electricity, or even move their operation to an area with cheaper energy costs. If any of these options are readily available, that customer may be lost to the home territory system anyway. Loss to a distant competitor would cost nothing to the home territory system but does use up excess capacity on the distant selling system and provides a more efficient option to the customer. With these assumptions, either solution, promoting and encouraging development of competitive markets or preventing their development, would have the same cost implications for the home system. The fully embedded cost would have to be absorbed elsewhere, so why not go with the choice that maximizes optimum resource utilization?

If the decision is to permit the competitive behavior to develop under either the first or third approach, the commissions will be forced to decide whether to impose the fully embedded costs of the system on those customers who do not have the ability to turn elsewhere. Alternatively, the regulatory authorities could decide to pass the competitively dictated advantages on to all customers with the consequence that the investors must absorb the risk of competitive rivalry, as in unregulated markets. We would move from a system based upon recovery of total embedded costs to one in which price is based on short-run marginal cost and reflects the instability of supply availability. Such a policy, like other recent developments, changes this industry from one of very safe, protected investments to a much more risky enterprise.

If the decision is to permit the advantages of competitive market access only to current or potential customers who have a real option to reduce demand or to locate elsewhere, the loss of the customer income would be limited to that which would be lost anyway. On one level this approach poses the practical problem of determining whether customers are bluffing when they say they will opt out if the cheaper service is not provided. On another level there is a serious question whether the discriminatory prices and service under such an approach would be legal or desirable. It was this kind of price discrimination problem that led the courts to reverse the FERC in the first attempt to deal with emerging competition in the gas market in the Maryland Peoples Counsel cases.10

Moreover, the Robinson-Patman Act has been held to apply to discriminatory prices of electric power.20 The possible legal exposure here would have to be carefully examined.

Let me conclude by turning to some of the underlying goals of antitrust policy. Today, the dominant goal, and for some the only goal, of antitrust enforcement is to create and protect competitive markets, which will ensure the most efficient satisfaction of consumer wants, that is, consumer welfare will be maximized. In this context one must include within the competitive market those situations in which entry barriers are low enough that even when there is only one or a few firms in a market they must behave as if competition were present. Otherwise, they invite challenging entry.

Through the years many other social and political goals have played a role in antitrust enforcement and perhaps even became dominant in the 1950s and 1960s. Today, they play a muted role, at best, in both enforcement effort and court decisions.

I would like to suggest, however, one complementary goal that I think has some importance, particularly as we address the electric power industry. Where possible without compromising long-term efficiency goals, I believe it is important to maintain diversity in ownership and management. I simply believe that more minds are better than few in addressing and solving problems, particularly in experimenting with new and different ways of doing things. This diversity in control is much more compatible with a constantly changing and fluid technology, including market response to new challenges. In this industry, in which only limited competition is possible in the best of situations, and in which entry barriers are high, diversity is a very important value to protect, at least where there is no large trade-off in long-term efficiency.

Turning to regulatory goals, they usually include control over exploitation of monopoly position, again to protect, from a different perspective, consumer welfare. This objective is consistent with antitrust policy. Other goals, however, frequently associated with public utility regulation do give rise to conflict with policy based on competition. The first is the idea that essential public utility services should be made available to all at modest prices even if that means subsidizing the service to some by charging higher prices, on a value of service bases, to others, that is, some form of universal service.

A second objective is the idea that the service should be avail
able on demand and on a very reliable basis. This objective has resulted traditionally in a significant shift of risk responsibility from the investor to the consumer. In most competitive industries management and investors assume the risk of mistakes in anticipating shifts in consumer demand patterns and in supply cost factors. Specifically, we do not expect production of supply to be capable of meeting demand, whatever it is, at a moment's notice. To get that kind of guaranteed service from our public utilities we have traditionally subsidized them through regulatory protection from competition.

To the extent that we introduce competition we undercut both of these objectives. Price gets bid toward short-run marginal cost, and the risk (and cost) of mistakes, of particular interest here, mistakes with regard to the presence of capacity instantly available to meet demand, is loaded on individual, not consumers. Management must be much more cautious in embarking upon costly expansion of supply to meet possible demand.

Exactly where the public interest lies over the long run in this mix of competitive markets fostered by the antitrust laws, on the one hand, and regulation, on the other, is not at all clear to me. On that note of certainty, I close.

Notes
15. Gulf States Utilities Co. v. City of Lafayette, Dkt. No. 84-132 (M.D. La.).
18. See Fisher v. City of Berkeley, 106 S. Ct. 1045 (1986); Southern Motor
Antitrust Issues in Bulk Power Supply


19. Maryland People’s Counsel v. FERC (I), 761 F.2d 768 (D.C. Cir. 1985); and Maryland People’s Counsel v. FERC (II), 781 F.2d 780 (D.C. Cir. 1986).


Pricing and Interconnection Standards in Transmission and Bulk Power

Lawrence R. Anderson

The electric industry is one of the nation’s most important infrastructure industries. While we may be able to do without universal bus, airline, and railway service, no one seriously contends that we could do without universal electrical service. The Federal Power Act mandates, among other things, the encouragement of an abundant, reliable, and economic national electrical energy supply. The FERC is charged with facilitating the accomplishment of the requirements of the act.

There has been much in the recent press about mergers, buyouts, other takeovers, and spin-offs in the industry, and, of course, we are concerned about what this means for the industry and the Federal Power Act’s statutory objectives. In today’s surplus electrical capacity situation, there has been an increasing interest in coordination transactions as utilities with excess generating capacity have aggressively sought to market their surplus. Not only

Note: The views expressed do not necessarily reflect those of the Federal Energy Regulatory Commission.
do these transactions decrease the costs to a utility's native load customers, but also in some instances they protect a utility's shareholders against penalties imposed by state regulators for alleged imprudence in maintaining excessive amounts of surplus capacity. Thus, a utility has incentive to market all surplus capacity at any price which yields some contribution to the fixed costs of idled capacity.

Of course, a selling utility would seek to obtain a 100 percent contribution to the fixed costs, thus fully compensating its native load customers for the cost of excess capacity. However, the level of surplus capacity in many regions of the country has resulted in a buyer's market where elements of competition have forced prices below the fully compensatory level. For example, we have seen sales of surplus capacity in the MAPP area (Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and portions of Montana, Michigan, and Wisconsin), where, due to an abundance of surplus power, utilities have negotiated rates for coordination transactions which yield only a 20–25 percent contribution to their fixed costs.

From the short-run perspective of society (notwithstanding this less-than-compensatory pricing, for efficient resource allocation), the sale of existing surplus capacity is worthwhile as long as the variable costs of operation are recovered.

In an attempt to increase buyer participation in power markets, utilities have expanded the coordination market beyond the short-term hourly and seasonal transactions of the recent past. Today, we also see longer term (5 to 10 years) sales of unit power or system power. For example, the Southern Companies have engaged in large power sales to Florida Power and Light. Tampa Electric Company is also selling to Florida. Each of these coordination transactions is under long-term contract arrangements.

The surplus market today has also affected the national market for requirements sales. We see municipal and cooperative requirements customers switch suppliers or use the threat of switching as leverage for substantial rate reductions. For example, certain Commonwealth Edison Company customers obtained transmission access from Edison via a settlement agreement. Two customers (the cities of Geneva and Rock Falls) have made arrangements to obtain new suppliers. Commonwealth Edison has retained three other customers by agreeing to long-term rate reductions. We have seen similar activity in the Arkansas region, where North Little Rock and other cities were able to negotiate reductions using their ability to switch suppliers as leverage. Utilities which previously protected their revenue position by opting for short-range requirements rate commitments are now offering rate reductions combined with long-term contracts in an attempt to retain customers over the "period of plenty."

There has also been much discussion about the pros and cons of regulators backing off and letting the marketplace set prices for wholesale electricity. The FERC's Southwest Bulk Power Market Experiment and the creation of a Western Systems Power Pool are evidence of the growing interest in increased competition. The advocates of market-based pricing argue that competitively set price signals based on value of service will better communicate the need for power and lead to greater industry efficiencies. It is argued that price signals set by regulatory ratemaking models put too much emphasis on cost of service (for the prevention of cross-subsidies and discrimination). Arguably, active rivalry between large numbers of sellers of power and between large numbers of purchasers of electricity will lead to more competitive energy markets. Large numbers of rival sellers and purchasers would tend to limit the possibility of individual actors using inordinate amounts of market power to abuse and distort a competitively based value-of-service pricing scheme.

In a conceptual sense, and being caught up in the spirit of increased pricing flexibility, I agree with this notion. However, another area may well be considered by regulators in our determinations on how we should proceed with less restrictive or more flexible bulk power and transmission pricing and transfer standards. I am not sure the industry is moving toward more active competition in all regions of the nation. Nationally, it appears that investor-owned utility interchange activity may have peaked or leveled off (see Table 1).

The much heralded development of more competition due to increasing surpluses of generating capacity may not materialize in many regions. An indication of the leveling off in regional surplus capacity is roughly demonstrated by the relative decline in capacity margin postures projected by NERC in its 1986 Reliability Review (see Table 2). There is also the increasing problem of inadequate transmission capacity, which stems from the balancing of relative costs and benefits in a complex, lengthy, expensive,
litigious process.

The level of competition in (and the relative size of) a coordination power market is a function of the number of willing and able buyers and sellers for particular services. In a given market, opportunity for coordination transactions depends on the availability, knowledge, access, timing, and pricing of surplus supplies. This may mean the commission should provide different kinds of pricing flexibility, specifically, pricing more sensitive to the degree of workable competition that exists for particular services in given power markets.

Table 1. IOU Interchange Out

<table>
<thead>
<tr>
<th>Year</th>
<th>Billion kwh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1975</td>
<td>355</td>
</tr>
<tr>
<td>1976</td>
<td>280</td>
</tr>
<tr>
<td>1977</td>
<td>305</td>
</tr>
<tr>
<td>1978</td>
<td>353</td>
</tr>
<tr>
<td>1979</td>
<td>333</td>
</tr>
<tr>
<td>1980</td>
<td>341</td>
</tr>
<tr>
<td>1981</td>
<td>352</td>
</tr>
<tr>
<td>1982</td>
<td>345</td>
</tr>
<tr>
<td>1983</td>
<td>331</td>
</tr>
<tr>
<td>1984</td>
<td>342</td>
</tr>
</tbody>
</table>


Where the Industry Appears to Be Heading

It is by no means certain that over the next decade there will emerge a national environment to foster more bulk power sales than we now have in terms of kwh, contracts, or market area. The simultaneous occurrence of several financial, technical, generation, and load conditions (none of which are necessarily involved with the exercise of monopoly power) may exacerbate the decline of regional supplies of surplus capacity and energy, which would otherwise provide the opportunity for coordination transactions in both competitive and less than fully competitive power markets.

Table 2. Estimated Regional Capacity Margins—NERC (Percentage of Planned Resources)

<table>
<thead>
<tr>
<th>Regions (U.S.)</th>
<th>Summer 1986</th>
<th>Summer 1995</th>
<th>Percentage point change</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECAR</td>
<td>20</td>
<td>20</td>
<td>-6</td>
</tr>
<tr>
<td>EROT</td>
<td>17</td>
<td>18</td>
<td>+1</td>
</tr>
<tr>
<td>MAAC</td>
<td>25</td>
<td>20</td>
<td>-5</td>
</tr>
<tr>
<td>MAIN</td>
<td>23</td>
<td>20</td>
<td>-3</td>
</tr>
<tr>
<td>MAPP</td>
<td>27</td>
<td>20</td>
<td>-7</td>
</tr>
<tr>
<td>NPCC</td>
<td>25</td>
<td>21</td>
<td>-4</td>
</tr>
<tr>
<td>SERC</td>
<td>25</td>
<td>19</td>
<td>-6</td>
</tr>
<tr>
<td>SPP</td>
<td>29</td>
<td>17</td>
<td>-8</td>
</tr>
<tr>
<td>WSSC</td>
<td>31</td>
<td>25</td>
<td>-6</td>
</tr>
<tr>
<td>Overall</td>
<td>26</td>
<td>20</td>
<td>-6</td>
</tr>
</tbody>
</table>

Diminishing supplies of utility-owned surplus generating capacity and the consequently higher prices might lead to the reluctance of regulators to rely heavily on competitive power markets.

Let us review the 1986 reliability data published by the North American Electric Reliability Council (NERC). NERC foresees an 80 percent probability that annual national electric demand will grow in a range from -0.2 to 4.4 percent. While projected available resources are expected to be able to support annual demand growth of 2.2 percent, there is a 50 percent likelihood that future peak demand will exceed this level to some degree. One-third of the new capacity is expected to be coal-fired, needing lead times of eight to ten years. About 13 percent of capacity additions needed through 1995 are coal-fired units not under construction. Of the 87,800 Mw of planned capacity additions through 1995, about 41 percent are not yet under construction. It appears that utilities are also moving toward smaller, shorter lead time generation alternatives; about 11 percent of the capacity additions thru 1995 will be provided by cogeneration, small power producers, and other nonutility generators.

Much of the corporate activity we are seeing today is related to new ownership of existing utility operating capacity or capacity
under construction, rather than to new capacity additions of the size likely to create marketable surplus capacity and energy which might enhance opportunities for increased competitive transactions. Examples are corporate activities surrounding the Alamito takeover, the Palo Verde sale-leaseback, the Seabrook buyout, and the now defunct Public Service Company of Indiana buyout attempt. Since these kinds of corporate arrangements merely substitute one owner or operator for another and do not lead to additional participants on the selling side, it is not certain that this will affect the degree of market competition. However, these corporate activities appear to consume capital without adding to the net supply of capacity represented by new entry, thereby increasing the real cost of energy to society without increasing overall productivity, while load continues to increase. The bidding up of prices for purchases of existing capacity and even the sale of existing capacity at a loss require additional financing on the part of some of the parties to the transaction.


The much discussed utility risk-aversion, in part caused by negative regulatory rate responses to new utility-owned capacity, but also the result of high fuel prices, cancelled nuclear plants, high interest rates, and reduced bond ratings, is a factor that has contributed to reduced utility interest in constructing future capacity additions. Notable examples include the delay or inability to recover costs related to the Wolf Creek (nuclear) and Colstrip (coal) plants. Only about 23 nuclear units remain under construction (see Table 3). Reduced reliance on large central power stations (such as nuclear units coming on line periodically) will limit sales opportunities from the traditional direct and indirect sources of substantial (if temporary) amounts of marketable surplus energy.

The fear of being second-guessed at rate setting time may extend to utility decisions on bulk power purchase transactions involving regulated utility and unregulated third party sources sponsored by nontraditional participants. If this fear becomes extensive, it could dampen prospects for sales of available surplus capacity and energy to utilities, although truly economic transactions should not be jeopardized. This is already manifesting itself through intraregional conflicts in the form of state disputes over responsibility for high cost power resources sponsored by traditional utilities. Recent examples include the AEP Pool (Rockport plant), the Middle South Pool (Grand Gulf plant), and Gulf States Utilities (River Bend plant).

Table 3. Nuclear Plants Not Operational

<table>
<thead>
<tr>
<th>Plant</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Palo Verde 3</td>
<td>1st quarter 1987</td>
</tr>
<tr>
<td>Harris 1</td>
<td>Low power license</td>
</tr>
<tr>
<td>Nine Mile Point 2</td>
<td>Low power license</td>
</tr>
<tr>
<td>Seabrook 1</td>
<td>Zero power license</td>
</tr>
<tr>
<td>South Texas Project 1</td>
<td>Under construction</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Perry 2</td>
<td>Halted but not cancelled</td>
</tr>
<tr>
<td>Beaver Valley 2</td>
<td>Under construction (April 1987)</td>
</tr>
<tr>
<td>Byron 2</td>
<td>Low power license</td>
</tr>
<tr>
<td>Braidwood 1</td>
<td>Zero power license</td>
</tr>
<tr>
<td>Shoreham</td>
<td>Under construction</td>
</tr>
<tr>
<td>Grand Gulf 2</td>
<td>Low power license</td>
</tr>
<tr>
<td>Limerick 2</td>
<td>Halted but not cancelled</td>
</tr>
<tr>
<td>Vogt 1</td>
<td>Under construction</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Comanche Peak 1</td>
<td>Under construction</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Watts Bar 1</td>
<td>Essentially complete</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Bellefonte 1</td>
<td>Rewelding</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Operational in 1988</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Under construction (1993)</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Under construction (1995)</td>
</tr>
</tbody>
</table>

Some parties contend that legislation to impose stricter emission limits on coal-burning plants could aggravate or precipitate shortages of capacity. Present and future coal generation could be curtailed, become more expensive, and be made less reliable by the installation of additional pollution abatement equipment. Sig-
significantly, much of the projected new capacity will be nonutility, including Qualified Facility capacity (see Table 4). However, QF capacity will not directly enter the open power market to promote price competition, since it will be earmarked for captive utility and industrial or commercial sponsors.

Table 4. Nonutility Generation Additions (NERC)

| 1986–1995 | Percentage of
| Mw additions | regional additions of total capacity |
|------------|------------------|-----------------------------|
| ECAR       | 212              | 2.4                        | 0.6            |
| ERCOT      | 8000             | NA                         | 7.6            |
| MAAC       | 567              | 13.3                       | 5.0            |
| MAIN       | 160              | 3.6                        | 0.9            |
| MAPP       | NA               | NA                         | 0.8            |
| NPCC       | 1773             | 11.0                       | 2.7            |
| SERC       | NA               | NA                         | 1.2            |
| SPP        | 300              | 4.6                        | 2.1            |
| WSCC       | 6775             | 31.1                       | 5.0            |
| TOTAL      | 12787            | 9.7                        | 3.1            |

NA: not available.

In addition, I see efforts by state authorities to control QF projects that will affect the amount of surplus and the number of utility participants in the power markets. Connecticut has reduced its avoided cost buyback rates up to 40 percent and established a QF project selection process to bring that state’s supply into equilibrium with its needs. The drop in buyback rate is attributable to the decline in oil and natural gas prices and changes in the avoided cost proxy plant from coal to a combined-cycle or a gas turbine plant. The new selection process favors projects that use renewable fuels or solid waste, are dispatchable by utilities, and most notably will not sell large amounts of power to utilities. Similar program changes have occurred in Idaho and New Jersey. The Vermont Department of Public Service is reportedly seeking a one-third reduction in the avoided cost rates. California is determining whether there will be any capacity that could be replaced by QFs during the next ten years.

The Tax Reform Act of 1986 modifies energy tax credits, increases depreciable life, and adds an alternative minimum tax; the act may also threaten the prospects for viable QF projects. Sizeable increases to QF supplies will be serving captive markets and therefore diminish opportunities for utilities to purchase surplus. True, utility capacity once serving industrial and commercial customers will become surplus if these customers sponsor their own QF capacity, and such utility surplus might be sold to other utilities. But to the extent QF supplies cannot be used entirely by the sponsors, QF surpluses will be created which must be purchased by utilities, who will participate less in the open market to meet their own needs for electricity.

Another factor that might dampen utilization of any surplus coordination supplies may be increased resistance by purchasers to return nonutility generation due to a perception of lower reliability. This perception may result from third party generators’ incentive to place short-term profit making above all else, rather than to follow the conventional utility industry bent of promoting long-term reliability. An example was the attempt of the Middle South Power Pool to restrict dealings with less reliable QF sources by not recognizing them, at its discretion, as sources of pool capacity. According to NERC, 31 percent of nonutility generation additions will burn natural gas, making them vulnerable to supply curtailment.

It is generally accepted that unrestricted availability of transmission capacity would broaden the geographic scope of developing competitive electricity markets. In actual practice, however, NERC noted that the loading of transmission lines to their reliability limits will increase during the next few years. I am concerned that this transmission “bottleneck” will preclude bulk power transfer increases between utilities conducive to increased power competition. Additional transmission capacity must undergo the lengthy licensing and jurisdictional processes. Some examples: (1) the completion of the Baltimore-Washington 500 kv loop has been delayed for more than 10 years; (2) the Houston Lighting & Power/Texas Utilities/Texas Municipal Power Agency circuit 345 kv line was taken out of service under court order in a dispute over right of way; and (3) the 155-mile 500 Mw South Texas DC tie between ERCOT and SPP has been delayed because of routing considerations and alleged health effects of electrostatic.
and electromagnetic fields.

Today's Coordination Power Markets

Reliability transactions (emergency and outage services) were the basis upon which today's widely diverse coordination market has been built. Utilities first interconnected to permit mutual assistance in times of outage. They quickly realized that mutual reliability from interconnection permitted effective sharing of reserves, eliminating unnecessary duplication. Thus, while increased system reliability was the purpose of interconnection, greater economies also resulted. These reliability transactions will remain an integral facet of the electric industry. In early years, compensation for emergency power was based on the return of like amounts of energy. In more recent years, rates have reflected minimum charges of a sufficient level to discourage abuse of emergency agreements, and I see no end to this.

Maintenance power is often considered a form of reliability service. While a utility is expected to maintain adequate reserves to meet its loads during a scheduled outage, the ability to purchase maintenance power decreases the amount of reserve needed. Moreover, it permits utilities to purchase, during outages, less expensive power than might be obtained internally.

Tomorrow's Coordination Power Markets

Today's surplus situation is not expected to continue in many regions of the nation. If capacity deficiencies develop, I expect the recent expansion in coordination markets to discontinue or, in some cases, even reverse. As reserve levels shrink in the future, utilities may be unwilling to provide maintenance power to others on a regular basis when it will affect their own reserve levels. Also, to the extent a utility has short-term surpluses, it may find that participation in the hourly short-term market (on a split-savings basis) generates larger revenues than sales of maintenance power. Under such conditions, while utilities may still utilize coordination sales, in the face of declining reserves and the uncertain reliability of QF resources, long-term transactions would probably be avoided. Coordination among utilities may revert to primarily shorter term reliability transactions and short-term (hourly and seasonal) economy transactions.

Of course, while reserves are expected to decline, surpluses can be expected to continue to occur in some regions during certain hours or months, and opportunities for exchange will exist. Those utilities with a desirable (inexpensive) fuel mix may still be able to participate in economy sales on a regular basis. However, to the extent the number of suppliers declines, utilities with available short-term energy will find themselves in a seller's market—able to demand higher prices for their available power.

For regulatory purposes, it is important to distinguish the tendency toward higher prices brought about by shortages of capacity in competitive markets and the tendency toward high prices caused by less than fully competitive markets. Regarding the latter, close regulatory vigilance must continue as pressure would be put on needy buyers to accept terms less favorable than those offered in competitive markets experiencing shortages. In recognition of these two circumstances, and in order to provide what we can of the benefits of competition, the commission's role as regulator may require the kind of flexibility suggested by Chairman Hesse in her remarks to NARUC in November 1986. In identifiably competitive situations, the chairman would consider letting the marketplace dictate prices; in noncompetitive markets, the chairman would consider simulating the pricing results occurring naturally in workably competitive power markets.

The Issue of Transmission Access

A major issue in today's surplus situation is transmission access. Investor-owned utilities seeking transit across a neighboring system for power to supplement or supplant the purchaser's own resources rarely allege denial to transmission access. Utilities which claim to have a problem with transmission access are generally municipal or cooperative customers seeking to wrest wholesale requirements service from the control of their primary supplier, that is, the local utility's service territory in which they lie. Some industrial customers as buyers and QFs as sellers also seek transmission system access. Thus, these parties can believe that Congress has been unwilling to set up a viable process under which those who seek such transmission access can readily get it.

I expect, however, that to the extent regional surpluses of generating capacity level off, transmission access may become less of
a concern. Wholesale purchasers who today seek to move off system may be forced back to their primary suppliers as alternatives shrink. In some regions, however, utilities with reduced opportunities for coordination transactions may begin to seek transmission business to replace the lost revenues from their reduced sales of surplus power.

Third-Party Generators

The decline of surplus capacity over the next 10 to 15 years may fail to sustain the fledgling development of non-QF independent (third-party) generators. It has not been convincingly demonstrated that independent investors will be encouraged to participate in constructing generating units under conditions where conventional utilities would not be, that is, where there no longer remains an assured customer base. Independent investors are probably not more likely than conventional utilities to assume the risk of plant construction without firm commitments (from conventional utilities or industrial customers) to purchase the output when construction is completed.

For example, I mentioned earlier Ocean State Power, an independent generator proposed to be located in Rhode Island. While Ocean State has assumed the risks of construction and some risks of operation, it has done so only after negotiating long-term purchase contracts with several New England utilities. Moreover, while utilities today may seek to purchase power rather than construct, the risk aversion of these conventional utilities could eventually extend to long-term commitments to purchase power from independent generators.

Of course, independent generators are also feasible only to the extent that there is adequate transmission capacity and access to it. The recent Ocean State Power filing represents the feasibility of third-party generation in the Northeast, where transmission access is not a constraint at present. In any event, since third-party generators may have no customer base in the conventional sense, the extent to which they are regulated (typical rate-making treatment focusing on fair return on investment, avoidance of price discrimination and cross-subsidies, and obligation to serve) may be inappropriate.
for purposes of establishing realistic price signals. (Transmission providers must be able to recover all of their costs, if there is a hope for improved access.) Third, transmission prices should incorporate some incentive for utilities to install new facilities and this is where the FERC can best enhance transmission access. Fourth, during shortages, prices should allocate any transmission capacity not needed for native load to the highest valued uses. (Limited transmission capacity should be used for those trades that produce the greatest net cost savings for the best use of existing facilities.) Fifth, transmission pricing policies should not allow the exercise of monopoly power. (Prices must be kept below monopoly levels, yet allow the flexibility and incentives needed to accomplish the first four pricing objectives.)

Conclusion

Some regions over the next few years may not provide additional opportunity for coordination transactions, which have traditionally constituted the bulk of the existing level of competitive energy market activity. Also, it is not clear that there will be large increases in the number of participants in coordination power markets. For these regions, new commission approaches to regulating coordination transactions may help to counteract these conditions. The Federal Power Act allows flexibility for the commission to be responsive, whether competition in particular coordination power markets contracts or expands. I look for the commission to put renewed emphasis on redefining the acceptable balance of risk and reward, especially with regard to new generation and transmission capacity, to provide incentives to encourage construction that will enhance bulk power transfer capability and operations, and to maintain the very high degree of system reliability that exists today.

Funding for Nuclear Power Plant Decommissioning Expenses: Considerations of Financial Assurance and Federal Tax Regulations

J. Robert Malko, Clarence E. Mougin, and Steven G. Kühm

Since the mid-1970s the cost of nuclear power plant construction has had a major effect on electric utility finance. However, the construction phase is not the only period when significant financing requirements are associated with nuclear power plants. Retiring and dismantling these plants at the end of their service lives, referred to as decommissioning, will cost the nation's electric utilities billions in current dollars according to recent estimates.

While decommissioning costs are not likely to be incurred for approximately 15 to 20 years for most U.S. electric utilities, these costs can pose a real financial problem today. Typical electric utility construction projects, such as generating plant and transmission line, require financing up front by the utility. The ratepayer

Note: The views expressed herein are those of the authors and do not necessarily represent the views of the Public Service Commission of Wisconsin.
pays the costs associated with these construction projects during their useful lives, but decommissioning is financed in a reverse fashion. The utilities collect revenues today for a project that will be completed in the future. This procedure is followed so that the ratepayers who benefit from the power generated from the nuclear plant also pay for its disposal. The utility in effect becomes a "custodian" of ratepayer-contributed decommissioning funds collected over the plant's life.

Some experts believe that decommissioning expense collection methods are inadequate in terms of dollars collected and assurance that funds will be available when needed. According to Cynthia Pollock, in a paper published in April 1986 by the Worldwatch Institute:

A look at the decommissioning funding mechanisms in place in various countries indicates that we expect our children to pay our electricity bills. Without savings programs that equitably share decommissioning costs and assure that funds will be available when needed, today's electricity customers are getting a free ride. The longer funds collection is deferred, the greater annual payments will have to be in order to accumulate enough money. Only by periodically updating site-specific cost estimates, instead of relying on generic studies for hypothetical power plants, can utilities hope to build sufficient savings. Waiving tax liabilities on the money deposited in trust funds and the interest earned on that money could also hasten the growth of decommissioning accounts.

Because many plants operated for years without collecting money for decommissioning, electricity customers and taxpayers will suffer the "after shock" of paying for retired reactors. The less money set aside while the plant produces power, and the more actual decommissioning costs diverge from estimates, the greater the after-shock will be.

While the cost estimates for decommissioning have been recently receiving attention, the degree of assurance that funds will be available when needed is frequently overlooked. Currently, most electric utilities in the United States do not set aside funds collected for nuclear power plant decommissioning expenses and use an internal nonsegregated approach. Rather, funds are used for any corporate purpose as these funds are collected. The ratepayer receives a credit for funds provided because the electric utility avoids borrowing costs by using the decommissioning funds to finance corporate projects today. By not setting aside funds, the electric utility is assuming that it will be able to borrow adequate money in the future in order to complete the nuclear decommissioning project.

Changing conditions and uncertainties in the electric utility industry, such as increasing risks associated with utility diversification and cogeneration, have created concern about the potential problems associated with having a large unfunded nuclear plant liability looming in the future. This concern, coupled with a 1984 change in the tax law relating to nuclear decommissioning expenses, has led some state regulatory commissions and some utility managements to consider using an alternative method for treating funds collected for decommissioning—the external trust fund approach. Under this method, funds are set aside as they are collected and placed in the trust fund outside the control of the utility. In 1985-1986 three state regulatory commissions made major decisions to adopt and implement the external fund approach for nuclear power plant decommissioning expenses for regulated electric utilities in their respective jurisdictions: Connecticut Public Utility Control Authority, Missouri Public Service Commission, and Public Service Commission of Wisconsin.

The primary purposes of this paper are to (1) analyze the degree of financial assurance that funds will be collected under the internal unfunded (nonsegregated) approach as compared to the external funded (segregated) approach and (2) discuss recent (1984-1986) changes in federal tax regulations concerning the treatment of funding of nuclear power plant decommissioning expenses. This paper first defines some basic concepts relating to the funding of nuclear power plant decommissioning expenses. Second, the degree of financial assurance that money collected by the two major alternative methods will be available when required is examined. Third, relevant changes in federal tax regulations are discussed.

Some Basic Concepts

Some basic financial and accounting concepts relating to the funding of nuclear power plant decommissioning expenses are presented and defined in this section in order to provide background information. These include: (1) segregated fund, (2) nonsegregated fund, (3) external method, and (4) internal method.
Segregated and nonsegregated funds refer to the treatment of the decommissioning expense money when it is collected by and comes into the electric utility. If the funds are nonsegregated, then the money for nuclear power plant decommissioning is not set aside as it is collected by the utility. Rather, the utility can use the funds for any proper corporate purpose. However, at the time of nuclear power plant decommissioning, the utility must accumulate the needed money, which would most likely involve a smaller portion of internally generated funds and a larger portion of external financing. By using the nonsegregated approach, the utility’s borrowing costs are reduced, to some extent, before actual decommissioning begins because the nonsegregated decommissioning funds can be used to finance projects that would normally have required the utility to borrow additional money.

If the funds are segregated, then the money for decommissioning is set aside as it is collected by the utility. The segregated fund is invested in relatively safe securities. At the time of actual decommissioning, the utility will have accumulated in the segregated fund a sum of money equal to the estimated cost of decommissioning.

The external method is defined as requiring segregation of decommissioning expenses outside the direct control of the electric utility. Two specific forms are the straight-line negative-salvage method and the internal sinking-fund method. It is important to understand that under both forms the funds are segregated, placed in a trust fund outside the direct control of the electric utility, and invested in relatively safe securities.

The internal method gives the electric utility control over the money collected for nuclear decommissioning. Two specific forms are the straight-line negative-salvage method and the internal sinking-fund method. Both charge utility ratepayers for future decommissioning expenses through the depreciation account.

A segregated fund can be internal by having the utility manage the investment or can be external by having a trustee manage the investments. A nonsegregated fund is by definition internal. Some people make a distinction between “control of the funds” and “access to the funds.” It has been argued that under any segregated approach the utility should control the fund (that is, select appropriate investments) but should not have access to the funds, except to finance decommissioning costs. However, if the state regulatory commission closely monitors the selection of the trustee and approves the trust documents, the need for the utility to control the fund is diminished.

Considerations of Financial Assurance

The degree of assurance that funds collected for nuclear decommissioning will be available when needed is an important consideration when evaluating alternative approaches. A proper decommissioning accounting method needs to provide reasonable assurance that adequate funds for nuclear power plant decommissioning can be raised when required without exposing electric utility ratepayers to excessive financing costs.

There are changes and increasing uncertainties facing the electric utility industry in the United States during the 1980s. Some of these include: (1) electric utility reorganization and diversification activities; (2) potential by-pass activities; (3) potential nuclear power plant accidents; and (4) medium to long periods associated with planned decommissioning of nuclear power plants.

Electric utilities have expressed and demonstrated an increased interest in pursuing diversification activities as part of corporate strategic planning. If an electric utility with a nuclear power plant were to pursue diversification activities via a holding company structure or a wholly owned utility subsidiary or structure in the future, then there is a risk that funds provided for nuclear decommissioning could be diverted to fund nonutility diversification activities. Financial and business risks associated with electric utility diversification exist, and efforts to insulate the utility from these risks could be unsuccessful.

Technological innovations in the supply of electricity may alter the use and value of traditional central generating station facilities. There could be an increase in by-pass activities, such as cogeneration, in the future. Methods of decommissioning accounting, such as the internal nonsegregated method, that rely on bondable property being available as collateral at the time of decommissioning face the risk that the value of the property may be inadequate to finance the decommissioning project.

The potential for a nuclear accident is a risk faced by an electric utility with a nuclear power plant. A major accident could significantly harm an electric utility in a financial sense and limit its ability to finance the decommissioning. Accidents at nuclear
plants could also result in the Nuclear Regulatory Commission issuing a general decommissioning order for all nuclear power plants in the United States. If this policy were to be implemented at a time when an electric utility were not financially strong, then the utility might be unable to finance the decommissioning.

It is important to note that the decommissioning of a new nuclear power plant is scheduled to start in approximately 40 years from 1986. There clearly exists significant uncertainty concerning activities and events associated with this long-term horizon.

In summary, considering these increasing uncertainties and the continuing need for state regulatory commissions to protect the public interest, it is appropriate and reasonable to place significant emphasis on financial assurance when evaluating alternative methods for funding nuclear decommissioning expenses.

The external method clearly provides greater financial assurance than the internal nonsegregated method for providing for the availability of decommissioning funds when needed. This conclusion is based on considerations of the risk/return theory and the portfolio theory of modern finance. Investing funds in a well-diversified portfolio of relatively safe investment instruments reduces the risk of funds not being available for nuclear decommissioning. Contrasting the external method with the internal non-segregated method, which invests all the funds in a single "risky" entity (that is, an electric utility), it follows that the external method provides greater financial assurance.

The issue of financial assurance also can be viewed in an agency theory construct. According to Barnea, Haugen and Sennett, "Agency problems arise from conflicting interests among parties to the corporate firm, such as management, capital contributors, employees, customers, suppliers, and the government." These researchers also state: "The term agency derives from the fact that corporate decisions are delegated to agents (e.g., management) who perform on behalf of other parties." When the internal nonsegregated approach is used, a significant degree of authority is placed on utility management (agents) to meet the needs of the group it should be representing, in this instance society (not the stockholder). Imposition of the external approach is a more effective way of providing a social contract for the utility management to meet societal goals regarding decommissioning.

Considerations of Federal Tax Regulations

This section discusses changes in the federal tax laws and regulations as they affect nuclear decommissioning. The Internal Revenue Code of 1954 was amended on July 18, 1984, to add Code Section 468A. This section created special rules allowing current federal income tax deductibility for cash payments to a nuclear decommissioning trust. The current deductibility lessens the overall costs of decommissioning. The temporary regulations for the 1984 tax law change were not formally issued by the Treasury Department until July 9, 1986.

The following discusses some of the major provisions of the temporary regulations for nuclear decommissioning costs (not inclusive of spent nuclear fuel costs).

To be eligible for the current federal income tax deduction, the taxpayer (utility) must have a direct ownership of a nuclear power plant and must make a formal election with the Internal Revenue Service (IRS) for application of IRC Section 468A.

Only the annual cash payments, no securities or property, in an amount to be discussed later, deposited in a trust organized solely for decommissioning funds are currently deductible. A separate fund must be maintained for each unit if the nuclear plant has multiple units. The interest income earned on these deposits is not currently deductible.

It should be noted that the Tax Reform Act of 1986 changed all references of a "Trust Fund to a "Reserve Fund." The significance of this change may be explained in the final regulations.

Two major limitations to deductibility are: That no deduction is currently allowable until (1) a schedule of ruling amounts (annual payments) is approved by the IRS and (2) cash payments for decommissioning expenses have been included in the utility's cost of service by a state public utility commission and are properly identifiable as such.

The IRS will approve of the utility's request for a schedule of ruling amounts if these amounts will project, after reasonable net investment earnings, administration costs and taxes to an amount no greater than the reasonable future decommissioning costs. Further considerations in the determination of IRS approval of the deductible schedule of ruling amounts are that the annual payments are level such that the current year's payment is not
less than the prior year's payment and include only a qualifying percentage. The latter is determined by dividing the number of years the decommissioning reserve fund will be in effect by the estimated useful life of the nuclear power plant as originally determined by the state public utility commission. Both the first and last year in the above calculations are whole years.

The request for the IRS schedule of ruling amounts must be filed 180 days before the first required decommissioning payment. All the required information needed to obtain an approved schedule of ruling amounts is contained in the temporary regulations. A revised ruling schedule must be requested at a minimum of every ten years or when the nuclear power plant life is extended; or the decommissioning cost of service is reduced; or the utility voluntarily requests a revised schedule. Allowable investments in the decommissioning reserve fund are: public debt securities of the United States; obligations of a state or local government, not in default; and time or demand deposits of a domestic bank or insured credit union.

The decommissioning reserve fund will be treated as a corporation receiving its own tax identification number and is subject to federal corporate tax rates. The qualified payment to this decommissioning reserve fund is excludable from its gross income, but the fund's tax liability is not deductible from its gross income. The reserve fund will have the same tax year as the utility. All distributions to the utility from the reserve fund are taxable income to the utility except for final distributions, which are returned to the ratepayers.

As previously stated, the effective date of the Section 468A amendment was July 18, 1984, while the temporary regulations were not issued until July 9, 1986. Therefore, the latter provide for the transitional rules needed to implement deductions for nuclear power plants in operation during the taxable years ending on or after July 18, 1984, or ending before January 1, 1987.

For these prior taxable years, the transitional rules provide for suspension of the 180-day period for requesting a schedule of ruling amounts if such schedule is requested before July 11, 1987; the time for making payments for the allowable prior taxable years; directions for the 468A election and amended tax returns; a schedule of ruling amounts be filed within 90 days of receiving the ruling amount; the method of calculation of the 1984 taxable year deduction; and the ratios for determination of the qualifying percentage for nuclear power plants in operation prior to July 18, 1984.

The Tax Reform Act of 1986 made several changes which both clarify and modify the 1984 law. (1) The reduction in the corporate income tax rates from 46 percent to 34 percent beginning July 1, 1987, affects the calculations of the future annuity payments to a decommissioning reserve. (2) The law clarified that decommissioning payments made to a decommissioning reserve fund and included in the 1984 and 1985 cost of service would be eligible for deductibility. (3) The 2 1/2 month period required for making annual nuclear decommissioning payments for taxable years beginning before January 1, 1987, would be relaxed by IRS regulations. (4) As mentioned previously, and for which implications are not known, the references to "trust" fund were changed to a "reserve" fund.

Summary

Considerations of financial assurance and changes in federal tax law have led regulatory commissions in some states, such as Connecticut, Missouri, and Wisconsin, and some electric utility management to implement an alternative method for treating funds collected for decommissioning of nuclear power plants—the external trust fund approach. Under this method, funds are set aside (as they are collected) and placed in a trust fund outside the control of the electric utility. It is hoped that the analysis and information presented in this paper will be useful to regulatory commissions, electric utilities, and policy researchers concerned with financial and accounting issues relating to the funding of nuclear power plant decommissioning expenses.
Funding for Nuclear Power Plant Decommissioning

Notes


2. In the Federal Register 50, No. 28 (February 1985): 5002, the Nuclear Regulatory Commission (NRC) suggests a 1984 cost estimate for nuclear decommissioning of $100 million per plant unit. In addition, according to the NRC's Licensed Operating Reactors Status Summary Report, May 1985, there are 94 commercial nuclear reactors in the United States. Using these two figures, the total cost estimate for nuclear decommissioning is $9.4 billion in 1984 dollars.


6. For information on the change in the tax law, see Internal Revenue Code s. 468(A), which is part of the Tax Reform Act of 1984 and also see Federal Register 51, No. 132 (July 10, 1986), Rules and Regulations, pp. 25033-25049, concerning proposed regulations.


8. The internal method typically does not require the segregation of de-

commissioning expenses. An exception is the segregated internal funded reserve ordered by the Florida Public Service Commission in 1982-1983. See Order No. 1987 and Order No. 2336 issued by the Florida PSC.


12. Ibid., p. 2.

13. For information on the change in the tax law, see Internal Revenue Code s. 468(A), which is part of the Tax Reform Act of 1984, and also see Federal Register 51, No. 132 (July 10, 1986), Rules and Regulations, pp. 25033-25049, concerning proposed regulations.

14. For information on the change in the tax law, see Internal Revenue Code s. 468(A), which is amended in part by the Tax Reform Act of 1986 at Act Section 1807 (a)(4).
The papers by Lawrence Anderson, James Meeks, and Robert Malko and colleagues address three important problems facing the electric power industry: competition in bulk power supply, competition in retail distribution, and accounting provisions for nuclear power plant decommissioning.

The Anderson paper relates some concerns about the future of this nation’s power supply and its influence on the industrial organization of the bulk power industry. He argues that insufficient capacity in both the generation and transmission phases looms in the future and suggests it will play a strong role in reducing and perhaps eliminating competition in the bulk power market. His argument depends upon the misconception that competition in electric power can only exist in a state of excess capacity. It is true that excess capacity, particularly when it is excluded from the rate base, whets the producer’s appetite for new and expanding markets, and perhaps the recent number of competitive ventures reflect this. Nonetheless, these competitive ventures have proved one thing only—that competition is workable in the bulk power market. It is a crucial error in logic to say that excess capacity is a prerequisite for competition to be workable. The truth is that excess capacity is necessary to demonstrate to the management of these industries that competition is workable. Competitive viability in the generation of electric power long has been demonstrated by economic researchers. The requisites for competition in the field are constant costs in the generation of electric power at the firm level, along with several potential suppliers in the market. The recent experiments to which Anderson alludes support the notion of the viability of competition.

The most important point to make is that competition does not depend upon the existence of surplus or deficient capacity; rather, the elimination of conditions of chronic excess and deficient capacity can only be brought about by flexible pricing and competition in markets where it is deemed to be workable. Flexible pricing ought to be used as a tool for encouraging entry into those markets which are or will be experiencing shortages. The FERC could use price flexibility and competition more widely and more effectively than it has in the past or seems to contemplate in the future. Indeed, many of the reasons given for not introducing competition in certain markets are actually reasons for doing so. In addition, it seems that there exists a gap in our empirical knowledge with respect to the level of competition in bulk power markets in the United States. If the FERC is to make judgments on where flexible pricing should or should not be implemented, studies on market concentration are needed. Moreover, the FERC must decide on the concept it will use for the relevant market, and the measure of concentration to be used.

Meeks provides an excellent and pragmatic guide to recent trends in antitrust decisions involving access issues to electric power transmission lines. Indeed, this survey alone makes the paper worthwhile. Although not central to his theme, it is interesting to note that Meeks disagrees with Anderson on the issue of an impending capacity shortage.

The critical question Meeks raises concerns use of antitrust laws to force access to and competition in the retail market. He shows in a rather forceful manner that efforts to promote such competition in many ways may be futile. The electric power industry over the last twenty years has undergone substantial changes, but these will seem minor in proportion to competition at the retail
level. Meeks's discussion of the various options states may have in insulating themselves from retail competition demonstrates that they face an insurmountable task. If retail competition is allowed, there will be no easy solutions. It can be expected, however, that the residential and commercial customers will pay the price.

At this juncture, one can raise several questions concerning our economic institutions and human welfare. Meeks points out that antitrust enforcement has pursued a goal of economic efficiency. It is no secret that such a goal is lauded by most economists; moreover, for most issues and problems, competition which results in economic efficiency is a proper solution. However, economic efficiency does not provide the fair, just, or moral solution. Its attractiveness lies in the fact that it provides a seemingly unique scientific solution. In some cases, economic efficiency represents the lowest moral common denominator, that is, it represents the only compromise attainable in a highly pluralistic and selfish society.

Philosophical issues aside, the opposite point is that retail competition may be thrust upon us by antitrust. The only factor which can prevent this would be a dramatic shift in antitrust goals. Residential and commercial customers would be most adversely affected by competition at the retail level. But since electricity represents a much higher proportion of the consumer's budget than telephone, it is doubtful that consumers will accept the results of retail competition as passively as they have the recent developments in the telephone industry.

Malko and colleagues make an important contribution in bringing attention to the issue of correctly choosing among accounting methods for nuclear power plant decommissioning funds. They provide convincing arguments that demonstrate the need for, at a minimum, the use of segregated accounting for such a fund. External segregated funding, however, has much in its favor from both the utility manager and the consumer standpoint. The question of agency is a pertinent one. Since management performance is evaluated by the short-run effects on stock price, most managers are short-run profit maximizers. This is evident in the fact, inter alia, that the payback method of evaluating investment projects is still widely used in industry today, as opposed to more correct methods, such as net present value. While it can be argued that the utility industry has less of an agency problem than

industry in general (due to careful monitoring by the regulatory process), external segregated funding still makes much sense in the light of agency theory. But if external segregated funding is chosen, responsibilities should be clearly established for alleviating a shortage of funds should such a situation occur at the time of decommissioning.

In concluding, it is imperative to recognize that technological breakthroughs in such areas as the fuel cell or some other new energy producing method could change the face of the electric power business far more than could bulk or retail power competition. Moreover, in order not to give the perception of contradiction as to the role of competition, some clarification is needed: The technical state of the electric power industry justifies competition in the bulk power segment, but not at the distribution level. Thus, one can support more competition in the field of bulk power supply and at the same time not support similar competition at the retail level.
Part Eight

Beyond FERC Order 436:
The New Natural Gas Industry – I
Pipeline Approaches to Open Access and New Transport Options

Charles E. Teclaw

Several issues of considerable importance to the long-run development of the natural gas industry are not currently receiving adequate attention. I will address some of these issues and suggest actions state commissions should consider to ensure that the benefits of a more competitive gas industry flow to residential and commercial customers.

The Producer Segment

Considerable coverage continues to be given to the producing end of the pipeline and to the relationship between pipelines and the FERC. From a policy perspective, the stage for future operation of these two segments of the industry—producers and pipelines—has already been set by Congress and the FERC.

Initially, the restructuring of the natural gas industry was set in motion through the Natural Gas Policy Act, reflecting Congress's desire to move from rigid regulatory pricing of wellhead production to market-based pricing. The period 1978–1982
can be described as the “gold rush” phase of natural gas production. Reacting in part to the shortages of the 1970s, producers and pipelines acted as though gas could be sold at any price in the future and engaged in what retrospectively seems to have been fairly ill-advised contracting behavior. During the next phase—1982 to the present—the market reacted to the oversupply caused by the “gold rush” with dramatically falling prices.

While certainly jarring, these developments were hardly extraordinary in terms of the economics of the industry. Indeed, natural gas at the wellhead has shown itself to be extremely responsive to supply and demand imbalances. As long as there is no further governmental intervention in pricing natural gas at the wellhead, the long-term future for natural gas production is secure and comforting. The price of natural gas will fluctuate freely in response to changing market conditions.

By raising the ceiling price of old gas through Order 451, the FERC has initiated a partial, and probably temporary, action at the wellhead to transform the natural gas industry from heavy regulation to dynamic competition. Total removal of wellhead price controls would be a more durable and efficient solution. Nonetheless, all of the structural actions needed in this segment of the industry are complete. At this point only the adjustments by the market participants need occur to achieve a substantially competitive wellhead market.

The Pipeline Segment

Over the last few years, attention has generally been concentrated on the pipeline segment and on FERC regulation of that segment. With the combined promulgation of the minimum bill rule (Order 380), the rule establishing a nondiscriminatory pipeline transportation program (Order 495), and the rule requiring pipelines to transport for their firm sales customers any price-controlled gas not bought by the pipeline (Order 451) the FERC has removed the major regulatory obstacles to a dynamically competitive gas industry. This is not to say that regulatory reform of this segment of the industry is complete. The FERC will be enmeshed in the implementation and fine tuning of these orders for some time to come. It is to say, however, that the FERC has courageously accepted the market’s mandate to “get out of the way.”

The State Commission / LDC Segment

The LDC/state commission nexus is arguably the most crucial link in the complete transformation of the natural gas industry. Yet, it has thus far received the least attention.

If LDCs and, by extension, state commissions do not adequately respond to the ongoing changes in the natural gas industry, then the potential consumer benefits of that transformation may never be realized.

Because of recent federal actions, LDCs now have options that were unavailable to them under the FERC’s prior regulatory practices. Wherever there is significant managerial discretion in a regulated utility, there should be an explicit regulatory policy on how the utility management is expected to exercise that discretion. The recent federal changes give state regulators either new opportunities or new headaches, depending upon one’s perspective. They also give state commissions new opportunities for mischief.

Let us briefly review the major FERC actions and discuss in greater detail the new options available to local distribution companies.

The first major FERC action was Order 380, under which the commission eliminated the inclusion of gas costs in minimum bills that pipelines impose on LDCs. This gave the latter opportunities to evaluate realistically gas purchasing alternatives to traditional pipeline system supply. Prior to Order 380, LDCs were committed for their supply to the local pipeline imposing the minimum bill simply because they were obligated to pay for pipeline gas whether it was taken or not. After Order 380, many LDCs could seriously consider buying gas from alternative suppliers, either competing pipelines or producers.

The next major accomplishment was the Order 436 program. Many pipelines were allowed to offer comprehensive, unbundled transportation services as part of their total service offerings. The commission also gave LDCs the opportunity to convert some of their purchases of pipeline system supply gas into transportation services.

Additional opportunities emerged through the commission’s actions in granting individual Section 7(c) transportation authorities. During 1986 the commission granted a large number of certificates, the vast majority of which went to LDCs, not for their
system supply, but rather for the benefit of their industrial customers. In the context of granting these individual authorities, there were very few LDC protests against the pipelines' willingness to transport lower priced gas to the industrial market and very few LDC demands for similar transportation services for residential and commercial customers.

Order 451 was the last commission action that resulted in new LDC opportunities. That gave LDCs the right to buy any "old gas" that its pipeline did not want to buy at the newly established ceiling price. While these provisions are not yet fully operative, they obviously will require that LDCs and state commissions carefully evaluate these new transportation opportunities for old gas.

A number of significant problems arose in 1986. First, LDCs were not aggressive before the FERC in protesting various pipeline actions that benefit the LDCs' industrial customers but either harm residential customers or are of no benefit to them. This phenomenon is manifested both in the willingness of LDCs to agree to Order 436 settlements proposed by pipelines and in the lack of LDC demands for equivalent Section 7(c) authority to serve the residential market. There are two possible explanations for this silence: It is either coerced or misguided.

 Pipelines have both higher wholesale supply gas and access to low priced spot market gas. Their natural incentive is to funnel the latter to their more elastic customers, the industrial, and the former to the inelastic residential and commercial market. The FERC and the courts have been critical of pipelines for explicitly allocating their gas in this manner.

LDCs do not generally benefit from directing the expensive gas to residential customers. Because of the minimum bill rule, they are not necessarily required to buy the pipeline's expensive supply, and in a perfect world they could probably serve both markets with lower priced spot market gas. However, the only way the LDC can access these spot market supplies is through the pipeline system. But the pipelines are reluctant to provide open access and equally reluctant to deny it when it is requested by an LDC. Thus, the LDC becomes an instrument that pipelines might use effectively to segment their market into elastic and inelastic customers.

Because the LDCs have a natural incentive to retain as much of their elastic load as possible, they become willing participants in the pipelines' market segmentation efforts. The LDC cooperates arguably because of the implied or possibly explicit threat that if the LDC demands transportation service for its inelastic markets, then the pipeline will not offer transportation service for the LDC's industrial customers. This may explain why most of the Section 7(c) applications are for service to industrial customers and why very few are for LDC system supply.

It is somewhat more difficult to explain why state commissions have been either unsympathetic to or uninvolved in these arrangements between the LDCs and their supplying pipelines. Plainly, the pipelines will not complain, the LDCs will not comply, the industrial customers will not complain, and the producers will not.

The only organized interests who can complain about this phenomenon are the state commissions or groups that represent residential customers. In the context of these 7(c) applications, the FERC has indicated that it is essentially the responsibility of protestors to bring to its attention any instances in which the phenomenon that I described above is at work. That is, it does not consider hypothetical claims of pipeline use of LDCs to segment markets to be sufficient grounds to send 7(c) applications to hearings to deny them on their face. Yet, groups that represent residential customers are fairly few and are often poorly funded. Consequently, these cannot be relied upon to prevent pipeline market segmentation. This leaves only the state commission to carry out this vital protective function.

The other possible explanation for this acquiescence in market segmentation is misguided silence. That is, it may be the view of many LDCs, and indeed of many state commissions, that it serves the public interest to keep the inelastic customers on the LDC's system for whatever fixed cost contributions these customers can provide. This theory was the basis for the FERC's Special Marketing Programs (SMPs), and it was found by the Court of Appeals for the District of Columbia to be unpersuasive. Whatever the benefits of market segmentation to residential customers, these same customers can be made even better off by purchasing inexpressible spot gas for LDC system supply. It would seem, then, that only coercion or misguided inaction can reasonably explain the deafening silence of state commissions and LDCs on the pipelines'
use of LDCs to segment the market. This silence represents neither a thoughtful nor an adequate response to a serious problem.

Two other reasons may help explain the reluctance of LDCs to be more aggressive in securing inexpensive spot gas for their residential customers. First, state regulators and LDC executives, having experienced the supply shortages of the 1970s, may be reluctant to place any great reliance on the spot market as a stable means of securing supplies. They may further reason that inelastic customers are the most vulnerable segment of the industry and will be more severely affected by any supply shortages that occur. Thus, continued reliance on the pipeline as the exclusive supplier for inelastic residential supply is seen as a responsible means of ensuring reliability and security.

I believe supply shortages are a thing of the past. Historically, they have been caused by governmental actions that kept the price of wellhead natural gas below the market clearing price. Consumers demanded more of this “cheap” gas than producers were willing to place on the market. Many commentators look at the state of the natural gas industry and note with alarm that at current prices the wellhead markets will be unable to sustain current production levels into the future. They note the rig count, the number of independent producers who are going bankrupt, the reserve/production ratio, the current low price of spot gas and conclude that shortages are again around the corner. I regard these conditions as a natural and beneficial consequence of natural gas markets struggling to maintain some equilibrium between supply and demand. The current state of the natural gas wellhead markets is a direct result of the overproduction that now exists. It is a natural adjustment process in such circumstances. The price of wellhead gas is expected to decline when there is an overabundance of supply. Similarly, as this excess supply is burned off, there will be an equally natural tendency for prices to rise in order to encourage production of additional supplies. Independent entrepreneurs will follow the developments of the natural gas industry. They know that at some point there will be a call for gas at a sufficiently high price to justify new investment. Thus, the price can and indeed must fluctuate to bring supply and demand into balance. Only governmental intervention, which I believe at this point is unexpected, will lead to future shortages.

The fear of price fluctuation can be a legitimate concern. The fear of shortages should not.

The second reason some LDCs may be reluctant to break away from the pipeline as the sole supplier is their inability to predict the future. LDCs may be legitimately fearful that once irrevocable commitments are made to rely on nontraditional suppliers, state commissions may question the judgment or prudence of the LDC in an ex post sense. In the past the LDC was usually presumed prudent in its reliance on pipeline supply, and purchased gas costs were routinely approved for pass-through to consumers.

There are two recommendations worth considering. First and foremost, state commissions must develop a set of rational and equitable policies. The LDCs should know up front the state commission’s position on tapping the spot market for system supply gas and on entering into long-term contracts with suppliers other than pipelines.

Second, state commissions need to adopt an objective test for measuring and judging the LDC’s actions. As noted above, wellhead markets are rapidly becoming dynamically competitive. One view of regulation is that, at best, it can be justified as a necessary evil only to constrain monopoly abuse. Absent any demonstrable potential for monopoly abuse in wellhead markets, I believe LDCs need only limited regulatory oversight of the exercise of their judgment to enter into supply contracts with both traditional and nontraditional suppliers.

One possible regulatory rule would be to allow the LDC to pass along only the current competitive price of gas as reflected in the spot market. This could be an average smoothed over a period of months to reduce volatility. By analogy, if an LDC entered into a contract for a ten-year supply of cars at a per unit cost well above the current cost of cars, it would seem improper for a state commission to allow the LDC to pass through that higher contract price. Similarly, if by engaging in an extremely entrepreneurial and prescient investment strategy, the LDC were able to negotiate a long-term contract for cars at a cost below the current price of cars, it would be arguably improper for the state commission to deny the LDC the benefits of that investment strategy. The reasoning is simple: On average and over time, it will be impossible to “beat” the spot price, except by accident.
Accordingly, the LDC should only be able to reflect the current commodity value of gas in its rates. If the LDC is risk averse, it will sign contracts only with prices tied to the spot market price. The customers of the LDC will never pay more for the commodity than the current commodity value of gas at any point in the future. If the LDC elects to bet or speculate on the future price of gas (or wheat or pork bellies) and, furthermore, signs long-term contracts based on that bet, then it should be held accountable for the consequences of its action and receive both the benefit and the detriment. When the current spot price is above the long-term contract price, then the LDC should be able to retain the difference. By symmetry, when the current spot price is below the contract price, then the LDC’s shareholders should be required to eat the difference.

This policy gives LDCs both the upside benefit and the downside risk. It keeps regulatory costs low since the spot market prices are relatively objective numbers at any given time. It allows a competitive wellhead market to protect consumers. It keeps the state agency from being unnecessarily intrusive into the business decisions of the LDC. It gives the LDC certainty as to what the rules of the game will be in advance so that it can make decisions based on known regulatory treatment. Most important, it makes the LDC fully accountable for its decisions.

The last area of concern is how to deal with an LDC that refuses to buy gas by taking advantage of its contract adjustment rights under Order 436, or its transport options under Order 451. Many LDCs are perhaps culturally resistant to weaning themselves from the pipeline’s system supply and assuming responsibility for finding alternative suppliers. Yet, the price currently being paid by residential customers for this culturally resistant behavior is approximately $1/mcf, which is the difference today between spot prices and pipeline average cost of system supply gas.

One option the state commissions could consider is imputing the spot price for whatever percentage of contract that could have been adjusted or quantity of gas that could have been taken under Order 451. Again, this is consistent with the view that the spot market can be relied on to reflect the current competitive price of gas. If the LDC has guessed correctly in continuing to use the pipeline as its sole supplier, and if the pipeline system supply is below the spot market price, then the LDC should be allowed to keep the difference. Similarly, if as is currently the case the pipeline system supply price is above the spot market price of the gas, then the LDC shareholders should be required to bear the loss. The LDC should not be allowed to gamble with ratepayers’ dollars when a neutral, competitive alternative is available. A competitive alternative best protects consumers from erroneous speculation by LDC executives. When a competitive alternative is available, speculation should take place only by risking shareholder dollars and not by risking ratepayer dollars.
Market-Responsive Contracts: A View from the Producer Side

Patricia Hammick

My subject is the producer’s view of market responsive contracts. I am going to discuss that subject in three parts: its historical perspective; the background economics of natural gas development and production which underlie producer contract needs; and the evolution to new contracting practices and some of their implications.

There is no doubt in my mind that we need to put the debate of who should bear the costs of the past behind us. We must all share.

We have faced the reality that the gas market must be flexible; that demand is elastic and that gas must compete with other fuels. We have not fully completed that transition, but we are on our way to achieving a more rational market system.

The challenge, as I see it, is now going to be how to restore trust in market and contractual relationships. After more than three years of contract turmoil, the view of producers is, in short, that we need to reestablish reliability in contract relationships. To resume major drilling efforts, there must be reasonable assurance that markets can be accessed and gas sold at a profit relative to the costs incurred.

Because we will likely enter an era of tighter availability of supplies in the not too distant future, it will profit all of us to reestablish good relations in purchasing practices now. Those practices must include price flexibility on the part of the producer, but they must also include some basic assurance that gas contracted for will be purchased on the part of the buyer and that gas not purchased will be able to be transported at reasonable cost to another market.

Historical Perspective

This brief review of the history of contracting practices is intended to offer a few lessons to take to the future.

In mid-1983 the wholesale price of residual fuel oil dropped, and for the first time in a long while it met the level of the price paid to producers for natural gas. Those two aggregate prices have moved in concert ever since.

The “market,” despite its warts and rigities, has announced to all that natural gas is a commodity, like copper or corn, or its competitor, fuel oil.

Our particular problems in gas markets may be attributed to those historically imposed rigities, in particular past contracting practices, past misperceptions about the value and availability of natural gas, the lack of an open and flexible transportation system, and lack of a futures market.

However, new production is no longer dedicated to markets, and if we accept the fact that gas is becoming a commodity we must accept the attributes of a commodity; that there will be boom and bust cycles and that in the future contracting practices must contain new, greater flexibility. This includes, in particular, contracts for transportation.

For a group of regulators whose job it is, among other things, to smooth the swings, one must beware of exacerbating those swings by requiring excessive purchasing practices on the part of the LDGs.

If long-term contracts for supply are an anathema of the past, very short-term spot purchases could become the anathema of the future.
Linking Supplies and Market to Ensure ROI

Prior to the 1980s producers locked in price schedules for their product for long periods, historically ten to twenty years. It was a heritage from earlier contracting practices, which provided for certificates of service to ensure recovery of investment in exploration facilities and in transmission and distribution facilities.

Originally, gas was considered a less than useful by-product of oil exploration, itself considerably less costly a venture than today. Indeed, finding gas had a value just a small step above drilling a dry hole. Because the major cost of the natural gas industry was viewed to be the cost of constructing a transmission and distribution system, interest was focused primarily on recovery of the investment in those facilities.

Beginning in the 1800s synthetic gas companies petitioned local and state governments for "eminent domain" authority in order to cross private property to lay distribution lines. Observing the large investment required in establishing the gas plant, these original investors sought protection from competition in the form of franchises to establish and maintain their monopoly.

It is worth noting that this relationship in the relative investment requirements of production versus transmission and distribution has changed dramatically. The transmission and distribution systems have matured. The premium is now on the cost of ensuring that investments are made in production facilities to provide supplies for the future.

Protecting Consumers

Manufactured gas had established a market in many U.S. cities by the turn of the century, and well into the early 1900s a mixture of natural and synthetic gas was sold to the consumer. When the technology of long distance gas transmission finally became practical about 1930, the precedent was laid for regulating the movement and sale of gas by franchised pipeline and distribution monopolies whose capital investment was secured by the guarantee of exclusive sales to the customers they served. Customers were presumably protected by guaranteeing the availability of supply at an advantageous price for years into the future. The operative presumption was that a monopoly could achieve economies of scale, but consumers would not realize these cost savings unless rates were regulated. Thus local and state authorities and then the federal government regulated the costs of transmission and distribution companies under the theory of cost-of-service ratemaking.

In 1954 the Supreme Court extended the concept of consumer protection to direct regulation of the wellhead price in its landmark decision, *Phillips Petroleum v. Wisconsin* (347 U.S. 672 (1954)). The burnertip price of gas in most sections of the country was then very close to its primary competition, oil. Although 80 percent of the consumers' price was transmission and distribution costs, the Supreme Court's decision in *Phillips* brought cost-of-service ratemaking to the wellhead first on a well-by-well basis and then in five and finally twenty-three producing area rate cases.

Commission jurisdiction has meant that producers must comply with the Natural Gas Act, including the certificate requirements which authorize a transaction to be "for the public convenience and necessity" under Section 7(c) and the rate requirements of Sections 4 and 5 guaranteeing "just and reasonable" rates.

For about ten years the wellhead price was maintained at the 1950 level while the Federal Power Commission considered the first area rate case (Permian Basin). The failure of case-by-case regulation led to the implementation of national ceiling prices in the 1970s.

However, the host of problems which began with the *Phillips* decision—creation of a dual interstate-intrastate market, overall declining reserves, and increasing demand for natural gas as the discrepancy between natural gas prices and alternative fuel prices increased—were not eliminated by national rates. The federal government intervened in the market to establish higher wellhead prices in the interstate market under the Natural Gas Policy Act in 1977. Its provisions demonstrated the acceptance by policy makers that ceilings below the market price simply led to fewer investments—investments that were insufficient to supply the demand created by holding prices below market, all of which led inexorably to shortages.

The contract practices which evolved in this market were defined either directly or indirectly by the regulations as well as market conditions. Since all prices were prescribed by law prior to the NGPA, the only opportunity to bid for the limited supplies was through better conditions for processing the gas and higher reliability in the takes. Thus take-or-pay provisions assumed greater
importance as purchasers offered higher guarantees that the gas contracted for would actually be taken and to enforce that "guarantee" by agreements to pay for gas as if it were taken. The consumer, protected by price controls, seeking more gas than was available, was presumed to be well advantaged by such contracts, which guaranteed the supplies sought.

When the NGA was passed a reversal was initiated in the prior constraints. Buyers focusing on the unsatisfied demand and facing higher ceilings on prices or no ceilings at all on the price of gas entered the kind of price bidding that led to a drilling bonanza. The consumer never saw the marginal prices of $3.00 to $10.00/Mcf allowed new gas. Most gas was aggregated by pipeline purchasers, and the various prices (from 28¢/Mcf to $10/Mcf) were averaged. The consumer only saw the average price, until the economic recession of the early 1980s, followed by the precipitous fall in international oil prices in the mid-1980s. Gas demand, falling throughout the 1970s but ignored because it was primarily industrial demand, suddenly became an important trend. It had become obvious that consumers of gas were not protected by the regulatory structure—had not been protected in interstate markets from shortages in the 1970s and were not protected by price controls in the 1980s.

Traditional Contracting Terms

Let me now turn to a short review of some of the traditional considerations in selling natural gas. Traditional first sales contracts are very complicated. There are complexities associated with the rights of multiple owners of the mineral interests and the variability of the physical characteristics of the gas itself, which must be co-neglected in a stream suitable for transmission and distribution. Moreover, any sales agreements which cover terms of many years are complicated by the further necessity to account for changes over time. Conditions which arise later, not covered by the contract, can lead to numerous amendments. When a changing history of state and federal regulations is added, the initial complexity is compounded many times over.

To illustrate, one need only consider the laundry list of provisions which most contracts contain: (1) the duration and scope of the purchase agreement; (2) the price, current and future, and provisions for escalation or reconsideration; (3) the quantity/take

and other conditions of delivery under varying circumstances; (4) the conditions placed on quality which involve processing or other treatment that makes the gas acceptable for delivery into the pipeline; (5) the agreement on how production-related costs and new production will be treated; and (6) the provisions for royalty owner payments and tax reimbursement. Other issues, such as measurement agreements, warranties on title for the gas, accounting provisions, and force majeure events, are also included.

To add to the confusion, many contracts bundle a wide variety of natural gas from different wells by price category and by field in order to meet conditions of purchase not only for total quantity but also for considerations such as daily and seasonal swings in deliverability levels and in the demand on those levels. Of these, the pricing and take provisions have received the greatest public scrutiny of late because they are the most obvious source of price effects as far as the consumer is concerned.

Up until 1982 the modus operandi of natural gas was that of a resource in limited supply, of higher worth because of its fuel characteristics and of diminishing availability because of the then current theories of resource depletion. It is not surprising in light of this attitude to find price provisions which did not envision a market of surplus supplies and rapidly declining prices. Moreover, as previously noted, consumer interests were protected—presumably—by the highly regulated conditions imposed by law, particularly on prices.

In order to deal with the existing requirements of law and interest ownership rights, a system of pricing and nonprice provisions evolved which would allow prices to move as allowed by law in an era and future of inflation and apparently insufficient supply. Thus, definite price escalation clauses (which provided a set periodic increase in price), warranty contracts (which guaranteed a given amount of supply), and minimum price clauses (which set a floor, at about 20¢/Mcf) were symptomatic of the pre-1960s, when there were stable economic conditions.

The clauses became less frequent as economic conditions became less certain. More flexible arrangements became the mode. Indefinite price provision referred to the maximum lawful price allowed for the category of gas, and most-favored-nation clauses guaranteed the same price paid to other producers in other con-
tracts with like quality and quantity and same geographic area. Oil parity clauses provided a price reference to oil or oil products, and redetermination and renegotiation clauses provided a pres¬
agreement that the parties would periodically come to a new price arrangement, under arbitration if necessary.

The purchasers’ interests were protected by buyers’ protection clauses like the “maximum price,” the “market out” if market conditions changed dramatically, the “FERC out” if the regulations were changed dramatically and the “force majeure” if acts of God prevented performance of the contract. The market out and the FERC out were less commonly used when the perception of the intrinsic value of natural gas was high, for example, during the 1960s and 1970s. In addition, there were and will be of necessity a plethora of nonprice conditions governing the conditions of taking gas and the compliance with state regulations.

Gas production from reserves discovered prior to passage of the NGPA which was sold into the interstate market remained dedicated to that market even after contract expiration. This meant the producer had no ability to negotiate better terms even when the purchaser’s contract rights expired. This fact influenced the producer to obtain high take commitments of the gas.

Take-or-pay provisions set out the amount of deliverable gas in daily and/or annual terms that would be taken or paid for if not taken, the make-up period by which gas paid for under the “pay” provision of a take-or-pay clause had to be taken, the develop－ment agreement between purchasers and producer for adding and paying for new wells which would be dedicated under the terms of the contract (for example, could not be marketed to another purchaser), the terms by which delivery of supplies could be aban－
donated, and the gathering and transportation provisions. Conservation measures in the state, such as proration rules for production, and the correlative rights of the owners and producers in a field were also considered.

What is important in reviewing the concepts of past contracting practices is that while some devices have become obsolete, some, like the price (renegotiation clause, remain useful. And some, like those which ensure the buyers’ intent actually to buy the gas is real and not just a contingency option, will of necessity remain (such as take-or-pay, or take-or-release and transport). In general, contracts for the purchase of gas at the wellhead are complex to serve the vagaries of the two markets which interface in the con－tract, including the exploration and production activity (with its legal obligations to the leaseholder royalty interests, lending institu－tions, and so forth, to receive equitable treatment despite the uncertainty in how much gas will be found and in what manner it will be produced and sold) and the purchasing activity (with its downstream customers, their fluctuating requirements, and so forth).

Royalty owners are an extremely important interest group to the producer. The royalty owner acts to maximize his revenues by pressuring for the highest possible combination of price and takes. The group includes thousands of individuals and the federal and state governments of 38 states. They are highly litigious and protective of their rights, which have been perceived as receiving the highest price available in the domestic market irrespective of contract terms or, at times, market conditions. Their reluctance to forgo their rights has added enormous complexity to the process of renegotiation of past contracts. They are a major force considered by the well operator (producer) in preparing or renegotiating a contract.

Economics of Natural Gas Development and Production

Let me briefly review some of the economic considerations of natural gas development and production which have led to the contracting practices of the past and which will necessarily dictate some of them in the future.

As for example, the end-user, you may have had little interest in the economics of development and production. You should have some interest in this now. Unlike fifteen years ago, the cost of natural gas at the wellhead is a major component of the buyer’s cost of using gas.

Finding and producing new supplies is a costly, complex busi－ness. While U.S. reserves of natural gas are large and the expected level of resource tremendous, the current proved inventory of 162 Tcf (for the Lower 48 states) that is readily producible is and has been dropping. Some of that decrease is a natural decrease in the size of the ready inventory due to improvements in the technology, and some is due to the increasing costs of holding the inventory.
However, the 30 percent decline experienced in 1986 in drilling activity due to falling prices, the surplus in deliverability of the inventory, and the seemingly greater market opportunity for gas suggest there could be less surplus in the available supply very shortly, within a year or two if the winters are cold.

Natural gas exploration and production is a high risk business. It must compete for capital like any other. Most significantly, following the fall in oil prices it is a business which must prove to investors they cannot do better elsewhere. Unlike the utility business with which it interfaces, its returns fluctuate; no regulatory body intercedes to stop bankruptcy; there is no minimum return provided; there is no guarantee that the fixed costs incurred will be paid by the purchaser.

In comparing this business with others, consider the difference in risks. For example, in 1984, the last year for which statistics are available, 234,000 gas wells produced 15.5 Tcf. A gas well costs about three-quarters to one million dollars to drill depending on depth, location, and so forth. There are additional costs for lease rights, geophysical surveys, and expenses incurred in drilling the six out of seven holes that are dry. Wells must be drilled continuously; one well currently serves an average of 20 residential customers. It takes six wildcat wells to find an economic producing well, and in addition some development wells are uneconomic to produce.

In considering the risks of the geology and the uncertainties of the market, the investment can be justified only if a predetermined return on investment can be anticipated based on discounted cash flow after tax. If not, money is invested elsewhere, the same as in any other prudent business investment decision.

Furthermore, while gas can and will be sold below its replacement cost in order to provide cash flow if the producing well has already been developed, new fields will not be developed if the expected market price is below the unit cost of development.

Most experts believe the current spot market in gas and the decline in drilling illustrates this fact; specifically, the current spot market is below the replacement cost for new gas, and thus there has been very limited new drilling.

New Contracting Practices

The experiences of the past, briefly outlined above, have created several trends in new contracting practices. (1) There are fewer definite and indefinite pricing provisions and more price re-determination clauses in contracts. (2) There are a growing number of alternatives in accessing markets through use of pipeline and distribution transportation facilities only which provide avenues to sell gas not taken by the original purchaser. (3) There is a move to resolve the costs of past contracting practices through various cost-sharing mechanisms such as direct billing and supply charges in tariffs to reserve supply. (4) There is a search to find new ways to ensure that supplies are connected to real and not just contingency demands.

From the producer's perspective the decrease in price realization has been painful but is being accepted and incorporated by necessity into his contracts with purchasers. However, the producer cannot store gas in order to serve customers who are not required to live up to purchase agreements. He will have to be paid some consideration as an incentive to provide the flexibility in production schedules that will satisfy his own economic requirements and the interests of the royalty owners.

Currently, end-use markets in many states operate on a least-cost use strategy and are swinging monthly among various sources of supplies, creating enormous gas-to-gas competition among a limited market—that market which has access to alternative transportation facilities. The results are temporary signals which do not reflect long-term economics. If played too long, the effects of this game could be serious.

The longer gas well drilling stays where it is, the more extreme will be the next price transition. It is in no one's interests to see a truly tight supply market reemerge. Preventing this from happening is possible by reintroducing some stability in purchasing commitments, by providing reliability once again to purchase clauses in contracts. Because of the surplus in deliverable supply and the lack of performance by purchasers on their take or pay commitments, producers now have to focus on developing contract provisions which provide a reasonable assurance of selling in the short-term that gas dedicated to a market which cannot use it.

Despite the increasing deregulation of the wellhead market and the flexibility asked of producers on price and take provisions, the transportation market has remained relatively inflex-
ible. Few pipelines are Order 436 carriers, and gas released into the spot market faces a difficult prospect in establishing the necessary transportation arrangements. Every time a sale arrangement is to be completed a new transportation certificate or opportunity must be established. The transportation system—impeded by regulatory requirements—seems unlikely ever to be as flexible as needed to accommodate a market which has few long-term contracts. Moreover, the secondary sale is almost always of less value than the primary purchase, since the primary purchaser in almost all cases retains first call on the gas. Creating a flexible transportation network is necessary to ensure that gas released from a contract will be able with reasonable assurance to find transportation to alternative markets. It seems axiomatic if consumers want flexibility to change supply sources they cannot demand permanence in contract relationships themselves without paying a premium and supporting the flexibility necessary in transportation relationships.

Let me conclude by relating a proviso offered to me by a lawyer friend which sums up the situation in natural gas markets: “Western civilization really hinges on only two things: first, that people stop at stop signs; and second that they abide by the contracts they sign.”

The Pipeline and Distributor Perspective of Market-Responsive Producer Contracts

James P. Holland

One thing I have learned over the last few years is to be prepared to unlearn as well as learn—selectively to cast aside certain management tools and ideas and pick up new ones in order to respond to changing conditions. Nowhere is this more obvious than in the natural gas industry, especially in light of the many changes that have taken place in recent years and those certain to occur down the road. These changes already are dramatically affecting the gas industry, and we can anticipate a continuing effect on future operations.

In Julius Caesar Shakespeare wrote: “There is a tide in the affairs of men which, taken in the flood, leads on to fortune.” Of course, this assumes that we have a boat, in the right place, at the right time, to catch the tide, and the necessary skills to launch and sail it. But it must also be the right boat. It must be designed to weather all types of sailing conditions. It must be prepared for all possible challenges—from shoals and storms to deep water and calm winds. Only if we have a vessel capable of responding quickly
to changing conditions will we be able to reach our ultimate goal. That analogy aptly applies to contracts for natural gas.

Historically, contracts to purchase natural gas called for deliveries over extended periods, contained rigid price and delivery provisions, and, depending upon conditions at the time they were signed, favored either the buyer or the seller. One feature they did not contain was flexibility: an attribute unnecessary until recently. Today, however, and in the future, flexibility must be a principal ingredient in all producer contracts. They must have the ability to respond quickly to changing conditions in the energy marketplace. Otherwise, neither the producer sellers nor the pipeline or distributor buyers are going to agree to the long-term contracts that will be necessary to develop the gas reserves needed to meet future needs at marketable prices. Indeed, without contract flexibility, natural gas will not be able to compete successfully with other forms of energy to increase or even maintain its present share of the energy market.

Like our boat, future gas contracts must be designed in such a manner that they will be able to weather all types of market conditions that occur down the road. We in the transmission industry recognize this. The distributors who are competing daily with other fuels for sales certainly recognize it. And, or the most part, producers recognize it. Therefore, I feel confident that all future gas purchase contracts will contain a variety of what we have called “out” clauses that give both the buyer and the seller an opportunity to modify or even terminate the contracts in response to market demands.

These “outs” will apply to both price and delivery obligations. For example, the purchaser may be given broad flexibility in the quantities it purchases without penalty, but the producer, in return, will receive the ability to sell to others that which the principal purchaser does not take. “Purchase or release” will largely replace “take or pay”. Similarly, the purchaser may have the right to reduce its price, but the producer will have the right to seek an alternate market if it deems the new price inadequate. The examples of new flexibility are almost endless. The bottom line is that both buyer and seller will insist upon it, each for its own reasons. And both will be willing to forgo the transaction if adequate flexibility cannot be negotiated. The price of a lack of flexibility is simply too extreme to permit any other course of action.

But future contracts are not the real problem at present. I believe they will take care of themselves. Both the buyers and the sellers have been burned so badly by rigid conditions in past and existing contracts that neither is going to be willing to agree to any long-term arrangements that do not contain market-responsive provisions.

The major problem lies with existing long-term contracts which contain inflexible pricing and delivery terms agreed to during periods when market conditions were or were perceived to be far different from today. It is the rigid contract terms in their existing producer contracts that are preventing more interstate pipelines from joining Columbia Transmission and voluntarily opening their pipelines to transport third-party gas on a nondiscriminatory basis. To do so would, they believe, expose them to millions, if not billions of dollars in take-or-pay liabilities.

Columbia Transmission became the first major interstate pipeline to accept the conditions set down by the Federal Energy Regulatory Commission in its Order 436. It was able to do so primarily because of an aggressive and highly successful program we initiated early in 1985 to restructure our nonmarket-responsive gas purchase contracts. I would like to elaborate on this program because, at the very least, it proves the problems of restructuring existing contracts and solving the take-or-pay problems facing interstate pipelines are not insurmountable. And the terms contained in our new contracts will permit them to respond rapidly to changes in the market forces.

Accomplishing our program was not an easy task, nor was it inexpensive. For example, settlements reached thus far with producers in the Southwest, which accounted for approximately 95 percent of the high priced gas we had under contract in that area in 1985, will cost Columbia almost $800 million over three years. But as a result of these and other successful, and costly, producer negotiations we have resolved virtually all of our take-or-pay exposure. In addition, more than 94 percent of the gas we produce ourselves or purchase from producers in the Southwest and Appalachian Basin is obtained under market-sensitive or low cost contracts.

As a result of these successful contract negotiations, Columbia Transmission now has the ability to redetermine the wellhead price of a large percentage of its gas supply every three months. It will
give Columbia and the 73 retail gas companies we serve in nine states a big competitive advantage in the energy marketplace.

Since renegotiating these contracts, Columbia has exercised its price redetermination rights four times. Each time we have proposed, and the producers have accepted, lower prices. Today, gas that once cost $8 and more per dekatherm at the wellhead is now being obtained for less than $1.55.

But, please, keep in mind that this downward pressure on wellhead prices is a direct result of the spot market and the surplus supplies available due to the current excess deliverability. Terms of our renegotiated contracts also give producers the right to seek higher prices when market forces dictate. As gas supplies begin to tighten, producers will begin exercising their rights under the contracts to redetermine prices, and wellhead prices will begin to move back up.

There are almost as many forecasts as to when this will occur—when the current deliverability bubble will end—as there are forecasts. In just the past few weeks, I have seen predictions that range from as early as this winter to as late as the 1990s. At Columbia, we believe the surplus will soon begin to disappear and that supply and demand will come into balance during the 1987-1988 winter.

When the surplus does disappear and wellhead prices increase, Columbia will not be obligated under its contracts to continue to take gas, just as during the past year producers have not been obligated to continue to sell their gas at the reduced prices Columbia has nominated. Our renegotiated contracts contain provisions that permit the producer to terminate the contract if he can get a better price elsewhere. Likewise, Columbia will have the option of terminating any contract if we feel the price the producer is asking is higher than the market will bear.

I think it is also worth pointing out that Columbia undertook to renegotiate its contracts and committed funds to gain more flexible contract terms without any assurance from its customers or the regulatory agencies involved that it would be able to recover those costs in future rates. I call attention to this because it is not the course being taken by other pipelines. Many are attempting to use their acceptance of the nondiscriminatory transportation provisions of Order 436 as a bargaining chip to obtain a mechanism that will guarantee recovery of virtually all of their take-or-pay and contract reformation costs.

Columbia believes these mechanisms are contrary to federal regulatory policies and the increasingly competitive nature of the gas industry. We are not opposed to a pipeline having the opportunity to recover any or even all justly incurred take-or-pay or contract reformation costs. We anticipate recovering a substantial portion of the funds we have expended in this area. However, we do not believe recovery of these costs should be guaranteed. Historically, such costs have been included in a pipeline’s sales rates where it must stand the test of the marketplace. This is the way Columbia plans to recover the costs it has incurred. It is also the method we have been urging the FERC to require other pipelines to use.

Granting pipelines carte blanche to recover all or a substantial portion of their past and future take-or-pay and contract reformation costs will, we believe, reduce their incentive to bargain hard with producers for market-responsive contracts. It may also reduce the incentive for producers to bargain since they, too, would know that eventually it would be the consumer who picks up the tab.

Let us consider long-term contracts themselves. Why are they needed? Why cannot we just let natural gas respond to free market forces like corn, wheat, or oil? There are many who view natural gas as a true commodity, able to respond like corn and wheat to market forces. But, unfortunately—or fortunately, depending upon your perspective—the natural gas industry does not exist in such a world. One day it might. But today it is still subject to regulatory and political restraints.

Also, natural gas is not a commodity in the true sense because most gas consumers do not have an alternate fuel they can readily substitute. It may be a commodity to an industry that can easily switch to oil or coal, but that is not the case for the homeowner with a gas furnace. While the virtues of competition and open access will continue to be debated—and one day may indeed dominate the industry—today and for the foreseeable future the utility dimension will dominate over the “what-the-market-will-bear” strategies of free market pricing.

After the bubble disappears, I foresee a gas market structure that will resemble a multilayered pyramid. The tip will be short-term, spot market purchases. These will be made either directly
from producers or from brokers who have agreements with producers to market their gas. Many people believe that today’s spot market will disappear with the deliverability surplus. I feel otherwise. I see a spot market continuing in the future. But I foresee it accounting for a much smaller percentage of the total market than it does today. And, instead of offering only bargains-priced gas, it will also offer gas at a premium price that LDCs, end-users, and, yes, even pipelines will use to solve near term emergency supply problems, in much the same manner as they did during the 1976-1977 winter.

A second supply segment will be gas purchased under relatively short-term contracts, perhaps as long as a year, that LDCs, industries, and other end-users negotiate directly with producers. The base and largest segment of this supply pyramid, however, will be gas that pipelines supply distribution companies under firm, long-term, price-sensitive contracts. LDCs are making it very clear that they want to continue to buy substantial portions of their supply from pipelines to support their heat-sensitive residential and commercial loads as well as high priority industrial processes. LDCs are looking to pipelines for this service because, over the years, pipelines have proven themselves to be the best aggregators of supply. They have the capability of developing supply from a multiplicity of diverse sources, thus assuring dependable service. They also have the ability to use economies of scale, storage, and complimentary markets to optimize load factors, thereby holding down rates.

At this juncture, I must note that some very large distribution companies, or integrated companies, such as those in California, also possess these abilities, but most distribution companies do not. Thus, I do not believe that either distribution companies or the myriad of brokers now offering gas for sale will be able to do as effective a job of developing long-term gas supply as pipelines. Therefore, the contracts they negotiate and sign will primarily be short term in nature, designed to meet noncritical loads. Pipelines will continue to contract for and sell most of the gas needed to serve high priority loads.

But if pipelines are to continue their traditional role of being the principal supply builder for the gas industry, they must have a clear understanding of their true daily and seasonal obligations to their customers. Only then will they be able to fashion meaningful gas acquisition programs.

We all are aware there are ample reserves of natural gas in this country awaiting development. But you can be assured that producers are not going to risk the huge sums required to tap these reserves based solely on the demands of a volatile spot sales market. They need long-term firm commitments before they can be expected to initiate the expensive programs necessary to find and develop new gas reserves. Pipelines cannot make such commitments without some assurance they will be able to sell the gas. The commitments that will lead to the development of the needed future reserves must originate with the distribution companies. They must send proper—and timely—signals if there is to be a stable supply of gas after the bubble. Historically, supply commitments have been the backbone of the gas industry. In my view, they must continue to be the industry’s driving force.

At Columbia, we have already begun the process of defining our true merchant function and the supply commitment our customers want from us by proposing what we call “seasonal entitlements,” or SEs. The principle is simple and straightforward: A pipeline should be obligated to supply only those volumes its customers reasonably expect to purchase. It should not be required to contract for and maintain large gas reserves that its customers may never take simply as a backup should other supply options fail to materialize. Under our SE plan, the retail gas companies we serve would nominate maximum volumes of gas they want Columbia to stand ready to deliver during the winter and summer periods and the volumes of gas they wish to have available to meet peak-day demand. Columbia would commit to meet the critical peak-load deliveries when they occur. However, on a seasonal basis our maximum obligation would be limited to only those winter and summer volumes the customers nominate.

I should emphasize that the customer has no obligation to purchase the nominated volumes or any percentage thereof. The SEs merely define Columbia’s level of obligation to provide service. The customers would, however, pay a demand charge based, in part, upon the volumes they nominate. In addition, should any curtailments be necessary in the future they would be based on the SE volumes nominated by the customers. In our view, this is as fair a method as can be found to assure supply development and to spread the responsibility and accountability for developing
new gas reserves evenly over the industry.

I do not mean to downgrade the positive effect increased transpor-
tation of gas by pipelines has had on business and the nation's
economy in recent years or to leave the impression that I believe
there will be no transportation of third-party gas by pipelines in
the future. What I do believe is that it is not in the overall best
interest of our nation for pipelines to be relegated solely to the
transportation function. They must continue to perform a mer-
chant function—buying and selling gas—if sufficient future gas
supply is to be developed.

Long-term, flexible gas supply contracts negotiated by
pipelines with producers will assure a stable supply and elimi-
nate the severe supply swings our industry has been experiencing
in recent years.

Open network architecture for the gas pipeline industry is nec-
essary for vigorous competition. One dimension of open network
architecture is ultra-free access to the transportation system of
pipelines. This unbundling of services creates significant risks for
the pipeline company. An outside party can use the transporta-
tion bottleneck to enter and compete in the traditional market
areas of the pipeline. This places the marketing function and the
end-to-end service function in jeopardy, which is exactly what one
would expect to happen with competitive entry. End-to-end ser-
vice is not compatible with open network architecture. A regula-
tory policy decision has been made to start to unbundle the ser-
vice historically provided by the pipelines, and one such service
is examined here, brokerage. The economic standards for com-
petitive brokerage are high: ultra-free access to the transportation
system of pipelines and no favored marketing provider. Institu-
tional arrangements must assure that the most efficient marketer
wins the competitive struggle. The issue of fairness is most clearly
evident when one of the parties performing the brokerage function 
is an affiliate of the pipeline providing the transportation access 
or when the pipeline itself offers end-to-end service.

Fairness dictates that discriminatory practices have no po-

tion in the marketplace. Independent brokers have raised many 
discriminatory issues associated with pipelines performing the bro-
kage functions. This paper will put forth eight of these fairness 

issues.

The first dispute is preferential pricing to favor system sales 
or sales by unregulated affiliates. The major focus of preferential 
pricing is on transportation conditions and rate structure. The 
independent brokerage industry condemns sales displacement rates 
as having no other purpose than to protect pipeline sales markets 
from competition. In addition, they attack multipart transportation 
rate schemes as effectively discouraging sales competition. The spe-
cific practice of which they express strong disapproval is a mileage 
based rate for long haul transportation clear up to the pipeline 
sales market area and then a postage stamp rate for any trans-
portation in that sales market area.

Taking these concerns in the order presented, one must ask 
the purpose behind the sales displacement rate. Recovery of the 
pipeline's revenue requirement is necessary from the pipeline's 
wholesale tariffs. The transportation tariff may be designed to re-
cover variable costs and capture little contribution to the capacity 
costs of the pipeline, since this transportation service is mainly on 
a "best efforts" basis. Independent brokerage sales which transfer 

volumes toward the transportation rate form can squeeze the 

pipeline's ability successfully to meet its revenue requirements. 
Certainly, the pipelines will not be indifferent to how these vol-

umes of gas flow through to customers. The regulatory standard 

should be that the transportation tariff should make the pipeline 

unconcerned whether the gas is for its own account or for some-

one else. This means that the cost burdens will have to be shared 
equally. It is important that rate design not bias the outcome 
for pipeline sales or for independent marketers. If the customer 
changes suppliers, there still has been no change in that customer's 
link factor characteristics. The degree of competition in gas end-

use markets will determine how much of a contribution toward 
sunk costs will be possible in either tariff.

The postage stamp market area rate complaint has validity.

On pipeline systems where the gas flows in both directions or en-
ters the system at many points, postage type rates make sense. But 
under normal circumstances, the distance element is a valid eco-

nomic cost consideration. Under the concept of open network ar-
chitecture, the customer's premise location should not be dictated 
artificially by the transportation element's rate form. A postage 

stamp rate may create this bias.

The second issue associated with pipelines performing the bro-
kage function is whether they will offer and charge lower trans-
portation rates to affiliates. Flexible rate authority should not 
come to mean sudden and favorable discounts to one's own affli-
iate. Here a simple regulatory rule requiring adequate notice of 
available discounts will assure non-discriminatory practice.

Insider information is the third issue raised by independent 
brokers. The practice of most concern is that the pipeline's mar-
keting affiliate has insider knowledge of the unavailability of 
pipeline receipt points. This allows the affiliate to arrange trans-
actions which do not use the unavailable receipt points. The com-
peing nonaffiliate is likely to put together a sales package that 
includes some of these. As a result, the transportation access is 
denied, and the sales transaction does not go forward. Further-
more, the customer has reinforced in his mind the idea that the 
nonaffiliate company is less capable in arranging transportation 
than is the affiliate. Certainly, a regulatory authority needs to 
determine how significant a problem is unavailability of receipt 
points and whether they have been used in a discriminatory man-
ner to favor affiliates. If it is concluded that this is an area of 
regulatory concern, then the standard of ultra-free access to the 
transportation system must be invoked. Unavailable receipt points 
are not compatible with ultra-free access. Their presence must be 
reviewed, and complete information about the nature of the re-
striction must be known to all possible users. Entire disclosure 
would be the necessary regulatory standard. This issue does not 
justify the further step of requiring a separate subsidiary for the 
affiliate marketer with the subsequent loss of economies of scale 
and scope.

The fourth issue of discriminatory practice concerns revealing 
to the pipeline company the upstream routing of the gas proposed 

for transportation. If the shipper has to disclose the entire routing 
of his gas before it reaches the pipeline's network, this limits the
flexibility of the marketer to switch arrangements for gas supplies. Since the broker's supply contracts are very short term (30-60 days), the ability to swing purchases quickly is important. In effect, the brokerage company is engaging in load balancing. With an open access transportation system it is no longer necessary that load balancing be performed solely by the pipeline company. To some considerable extent, when the pipeline becomes a common carrier, load balancing functions are shifted upstream. There may be good reasons for the pipeline's continuity of service operations to know the upstream routing, but this information should only result in loose control on the transaction, not in tight control. Restrictions on load balancing practices by brokerage firms are not compatible with open network architecture. The concept allows for the processing of load to take place anywhere along the network.

There is the possibility for anticompetitive results if the pipeline communicates information to its affiliate brokerage company about the independent broker's sources and rates of supply. This information may give a competitive advantage to a pipeline's affiliate. The same facts about the affiliates' sources of supply are probably not available to the independent brokerage company. This is another reason to argue that the information requirement on upstream routing be of a generalized nature and loosely enforced.

The information requirement issue leads into a discussion of the fifth worry of independents. In effect, the pipelines are saying to the independents that load balancing must be accomplished in a nearly perfect manner (2-5 percent). If it is not, a substantial penalty will be imposed. Independents will not be swayed by a load balancing problem to the pipeline network. The out-of-balance problem may take two forms. The first occurs when the independent's gas deliveries to the pipeline do not equal nominations to the pipeline, the second when the independent's deliveries to the pipeline do not equal deliveries by the pipeline. The first instance deals with the circumstances discussed previously as upstream balancing. It seems unfair, on the one hand, for the pipeline to restrict load balancing operations by discouraging swinging by independents to alternative suppliers and, on the other hand, to extract a substantial penalty (ranging as high as $10 per mMBtu) where they do not meet their nominations.

The second out-of-balance problem has not been examined. It requires the independent broker to load balance in a near perfect manner on both ends of the transportation network. Since many of these transactions are not a significant portion of the total capacity of a pipeline, the question may be raised as to how important an operational problem this constitutes. The penalty should have some cost relationship to operational problems.

A more serious charge from independents on balancing requirements and penalties concerns discrimination. Rigid balancing is not required of the pipeline's marketing affiliates. Hudson Gas Systems (an independent) claims to have learned through its customers of cases where marketing affiliates are measured at only one end of the pipeline. What this implies is that the load balancing will be done by the pipeline itself, and no imbalance penalties will ever be charged. Obviously, if this kind of discrimination exists, then a fair regulatory standard would require that the service be available to all shippers.

The sixth issue occurs when the pipeline gives capacity transportation preference to released gas from the pipeline's contract obligations. This is gas the pipeline is contractually obligated to purchase but has given back to the seller in return for a reduced contract obligation. The discrimination problem arises because this gas is more valuable by reason of superior access to the pipeline's network. A competitive disadvantage of inferior service is attached to the independent broker's gas. Ultra-free access to the transportation network mandates that capacity preferences are unacceptable unless sold on a nondiscriminatory basis under a premium service tariff. This illustration points out the transition problems that the industry faces under deregulation. Take-or-pay contracts which shift the risk from producers to the pipelines cannot linger in the competitive environment. More important, they cannot be used as excuses for preferential treatment of access. Otherwise, we cannot be assured that the most efficient brokerage provider is winning the transportation capacity. The economic principle of all this is that the take-or-pay gas is too expensive to be competitive in the end-use markets. Open network architecture merely drives home this point.

Authorized overrun sales are the seventh issue in the brokerage debate. Many pipeline tariffs contain an overrun service for customer purchases in excess of the contracted demand. The com-
petitive issue comes about because of the rate design used. Under the United method of rate design, 75 percent of fixed costs are tilted to the commodity component. The Seaboard method assigns 50 percent of fixed costs to the commodity portion. The modified-fixed-variable method places only return and associated taxes in the commodity charge. As the commission moves away from United to the modified-fixed-variable rate design, the commodity charge is substantially lowered. The problem is that the authorized overrun service charge is often set at the commodity charge of the two-part contract demand schedule. As the commodity rate level falls, the interruptible transportation rate level is caused to be at a much higher level. The nonaffiliate sales broker argues that the transportation rate of the pipeline’s sales gas is based on the rate for transportation of gas purchased from a nonaffiliated company. There is no difference in the transportation service being offered.

Certainly, this complaint raises some important regulatory issues. One implication is that peak responsibility pricing distorts the efficiency of gas brokerage services. Nothing could be farther from the truth. As competition for gas sales among elastic customers increases, a rate design that tilts fixed charges to the commodity component is unacceptable. Competition drives out tilt. The modified-fixed-variable rate form is a strong step in the direction of proper rate structure. The last thing that is desirable in the design of rates is artificially to overprice the cost of off-peak service, the elastic service.

The overrun service tariff problem can be handled by certain and clear rules for implementation. A contract demand or nomination upon which the demand charge is based has to be realistic. If it is, regulatory concern ends. The issue then becomes similar to one discussed earlier. The transportation tariff should make the pipeline unconcerned whether the gas is for its own account or for someone else. The cost burdens will have to be shared equally whenever the load factor characteristics of overrun service and transportation service are the same. Then the overrun service tariff should be simplified into a single transportation tariff. If the load characteristics are not the same, rate discrimination is justified.

The final issue reviewed concerns minimum bill provisions. Can these bind the customer of the pipeline for purchase of system supply? Is it an anticompetitive weapon to force exclusion of alternative gas supply sources? Are minimum bill provisions imposed only on partial-requirements customers who are supplied by more than one pipeline? The economic implications of the use of a minimum bill provision are complex. A careful study of these questions is necessary to assume that no brokerage service is favored. However, it must be pointed out that any study of the consequences of minimum bills should address the pipeline’s obligation to serve. If it is found that minimum bill enforcement is inappropriate in a context of open network architecture, it would mean that supplier of last resort considerations also must be abandoned.

In conclusion, competition demands that the pipeline’s transportation system be open without prejudice to any broker. This economic standard of ultra-free access assures that the most efficient marketer wins the competitive struggle, even if that supplier is the pipeline’s affiliate. Protection of an inefficient independent broker is no more socially desirable than a policy favoring a pipeline’s affiliate. If it is to be our social policy that gas brokerage is in the public interest, then the principles of open network architecture are required. The pipeline unbinds its services, competes as a nonfavored supplier to gas markets, and offers up its transportation network to all comers. From the many issues brought forward in this study, it is clear that regulatory barriers and institutionalized mind sets are part of the problem. Rate designs that insist on bundling end-to-end service, regulators who require fully distributed cost allocations, and pipeline managers who pay more attention to stability and certainty of pipeline operations than selling their services are of little interest to the marketplace. With open network architecture, the services offered will be customer designed and customer driven. We need to stop telling our customers what it is they want or how to use our network. We need to start listening to them. That is what competition is all about.
Comments

Margaret Ann Samuels

I grew up on a farm and carry with me always the South Dakota farm girl perspective. It is remarkable how applicable the farmer's position as producer and the consumer's position with respect to farm products are when considering the natural gas industry. Both farming and gas drilling are high risk ventures; both rely on the middleman—or have until recently—to transport and market their product. Farmers certainly know what gas producers are currently going through.

The middleman in food products delivery is not regulated, however. Thus, food product prices reflect demand and supply forces, but the farmers' prices remain at a level which enables high profits for the middleman.

Maybe what farmers need is take-or-pay contracts. Naturally, as a consumer advocate, I would never suggest such a thing. But how about multiyear contracts with flexible pricing provisions, allowing either party to initiate renegotiation? Whatever the right answer is for farmers, it seems clear from the events of recent years, as well as the presentations by both Patricia Hammick and James Holland from the producer perspective, that this will become the pattern for gas purchase contracts in the near term. Indeed, the pattern is already established. The purchasers, however, are and will continue to be not only pipelines but also local distribution companies (LDCs) and gas marketers and brokers—and, in many instances, large industrial gas users.

The Office of Consumers' Counsel agrees that flexibility is the key to proper natural gas purchasing, whether by pipelines or others who are obtaining gas for captive markets, which now are primarily residential. What OCC argued in attacking the purchasing practices of Columbia Transmission in the 1981-1983 period under the "abuse" standard of the NGPA was exactly that: The pipeline had ignored the marketability of its gas and disregarded its duty to consumers in binding itself to ever escalating gas costs with no means of responding to decreases in demand due to high costs, conservation, or economic or weather fluctuations. Clearly, the flexibility about which we are now hearing so much was needed considerably earlier than many contractors realized. Many are familiar with the findings of the FERC and the D. C. Circuit Court of Appeals that ignoring marketability of gas purchases constituted reckless disregard of duty under the Natural Gas Act and that Columbia's 85-90 percent take-or-pay clauses in high cost contracts had become imprudent, violating Section 5 of the Natural Gas Act. The issue of abuse was remanded to the FERC, and no action has been taken.

Columbia Transmission has shown in the past two years that it is possible to face the music and remedy inflexible contracts. Along the way Columbia has spent a lot of money, written off some gas costs, and bought its way out of high take-or-pay levels, high prices and lack of market-out clauses. It remains to be seen how competitive Columbia will be at the end of the two-year settlement period during which this has taken place. Certainly, its current gas prices are still very high, and consumers continue to suffer from the lack of flexibility in its contracts.

Various commentators have recently noted that the lower gas prices about which the producers are complaining are not reaching the residential or so-called captive consumer. (Lower farm prices are not reaching the consumer either. I might note, but for a different reason.) Charles Teclaw has aptly identified the causes. Many LDCs have failed to diversify their system supply and to break...
away from reliance on high-cost pipeline supply for their captive markets. State commissions must recognize the need for them to do this and set policies which will ensure that they do. To the extent that LDCs are failing to procure the benefits of low-cost supplies available for their "core markets" because of fear of second guessing, the state commissions do need to set guidelines and policies to provide incentives to do so—and to affirm that the LDCs will be made to answer for failure to do so.

In Ohio for several years, the Ohio commission has now taken up the standard and is finally encouraging local utilities to develop their own gas procurement abilities, reduce their dependence on pipelines, and diversify their system supply. Some have been doing it on their own. Although the large users which threaten to leave the system are the primary beneficiaries, the lower prices are also reaching the core market consumers: you and me. Gas prices of some companies to residential and small commercial consumers have dropped 20 percent or more since 1983-1984. There are still enormous differences in rates from one company to another, reflecting the supply picture. Even though the settlement with Columbia Transmission in 1985 brought an immediate reduction of 9-10 percent in gas costs to the many Ohio LDCs which purchase from that pipeline, Columbia has not reduced its gas costs any further. Thus its Ohio affiliate, the largest distribution company in the state, has been the highest cost market in the state. (I should note that this is expected to drop dramatically by April 1987.) Consumers served by the affiliate pay gas costs nearly $1.50 per Mcf higher than those served by a nearby, much smaller gas company.

Ironically, the service territories of these two utilities are contiguous. Ohio does not have franchised service areas for gas companies, and these two distributors are competing vigorously for large users which can be served by both. Some cities are even planning to assert eminent domain over distribution facilities in order to switch suppliers.

Ohio is a ferment of transportation activity; virtually every gas user which can locate its own supply of gas or a broker to do that task and obtain transportation has done so. Indirectly, consumers are benefiting as many schools and hospitals are now acquiring gas through broker-arranged transportation. (Note that I am using broker as shorthand for both marketers and brokers.) There are even new gas distribution companies springing up, threatening to compete or succeeding in competing for large users on established distribution systems. The next year or two will tell whether this is healthy competition or whether residential consumers will be injured by cream-skimming—and whether state regulators will permit this.

One reason, obviously, that residential consumers are not able, in general, to obtain the full benefits of lower costs associated with direct transportation of market-priced gas is that pipelines do not provide open transportation of gas owned by third parties. Pipelines apparently are not willing to risk opening themselves to Order No. 436 without some purchase commitments or other take-or-pay protection guarantees. It should not be forgotten that Columbia Transmission obtained two-year purchase commitments from its customers in the purchasing practices settlement in early 1985, well in advance of opening its pipeline to transportation under Order 436.

Frankly, it is not surprising that pipelines are pressing for this advantage. The FERC has not so far disallowed any purchased gas costs under the NGPA, nor has it disallowed any payments or buyout costs as imprudent, no matter how outrageous. Nor has the FERC acted on the remand from the Court of Appeals in the Office of Consumers' Counsel case to set a new standard for "abuse" under Section 601 of the NGPA. However, take-or-pay levels in many existing contracts clearly make system supply gas on most pipelines unmarketable to all but the captive consumers on LDCs with no (or unexercised) options. If the FERC would do some disallowing, as OCC and many others have urged, it could perhaps help break the logjam. Similarly, state commission disallowances such as suggested by Tcclaw could hasten market equilibrium. (I was glad to hear Hamnick say "we must all share." Too many attempts are made to put all costs on captive consumers. This is one problem with modified fixed-variable rate design.)

On the question of affiliated marketers discussed by Curtis Cramer, OCC has many of the concerns expressed in the rulemaking positions that prompted the FERC's Notice of Inquiry. We have expressed these to the Securities and Exchange Commission in cases involving public utility holding companies and plan to express them to the FERC. Both Columbia transmission
Comments

and Consolidated Gas Transmission Corporation, the two major pipelines serving Ohio, are owned by holding companies which need SEC approval to form a marketing company, pursuant to the 1935 Public Utility Holding Company Act. Both have had applications before the SEC. Columbia withdrew its application in the fact of opposition by OCC and others. Consolidated's is still pending.

However, it is my observation that it may not be necessary to have a marketing affiliate in order to exercise market control if there is a distribution affiliate to act as agent. Yet, Ohio LDCs are obtaining transported gas supplies from the marketing affiliates of a number of pipelines other than their direct suppliers—that appears to be working to the advantage of consumers so far.

Holland points out, and Hammick implies, that producers need long-term firm commitments before they drill. Unlike farmers, who plant every year whether it pays or not, producers many times just stop drilling—or even cap their wells and pull out if the price is inadequate in their eye. Consumers do need natural gas supplies—at fair, market-related prices. I believe we will benefit by a balance between the merchant function and the transportation function performed by pipelines. If a standby charge is needed to maintain some optimum backup level of sales gas availability, I believe we would support a fair standby charge. This clearly is at issue in cases, including the Columbia rate case, now pending at the FERC. Here we will see the separation of the timid or reluctant LDCs and those willing to take on new challenges.

In summary, the supposed benefits to consumers from transportation of market-priced gas are only slowly trickling down to the pipelines. Contract reformation is still a crucial ingredient in transforming pipeline sales gas into a competitive component of LDCs' system supply. Consumers should not be forced to continue paying the penalty for pipelines' failure to negotiate market-sensitive price and take-or-pay clauses just because they have no alternative supply. The FERC still has an obligation to consumers. The new gas industry environment gives new opportunities to state regulators and LDCs to do their jobs in creative ways. Consumers will be cheering them on.

Part Nine

Beyond FERC Order 436: The New Natural Gas Industry – II
What Options Do State Commissions Have to Control Gas Costs and Minimize Price Discrimination?

William H. Smith, Jr.

My topic is controlling natural gas costs and minimizing price discrimination in the world as it exists after FERC Order 436. State regulators are required to do so, but their requirement stems from a statutory plan which predates the monopoly utility model we assume in most of our regulatory practices. The plan has been used without resort to company-specific rate-of-return regulation. We must remember that, in the long run, the rate-of-return model is just one way to simulate competitive pricing.

The standard regulatory statute has only a few basic requirements. Prices and practices must be just and reasonable. They must be published. They must be nondiscriminatory1. Entry and exit are often controlled. This regulatory scheme has been applied to rail, truck, and steamship service, taxis, stockyards, air carriers,

Note: The views and opinions expressed are not necessarily those of the Iowa State Utilities Board.
and warehouses. This structure also applied to manufactured gas; before passage of the Natural Gas Act in 1938 most factor inputs of a gas utility were not regulated. The fact of federal regulation of wholesale gas supply has dominated state regulation of natural gas service, however, from 1938 until the present.

Legislative and regulatory events from the Natural Gas Policy Act of 1978 to FERC Orders 436 and 451 have effectively stripped away much of the overlay of federal regulation from the retail gas industry. Two premises appear no longer debatable. First, Order 436, where and to the extent it is effective, severs gas commodity transactions from gas transportation. Second, by virtue of the NGPA, Order 451, and related regulations, the gas commodity is predominantly and increasingly unregulated, at least as to price, at the wholesale level.

Three corollaries which flow from these premises are increasingly evident in today's gas industry. First, the market sets the effective price for the gas commodity. Second, supplying the commodity need not be a monopoly function where open transportation is available. Third, the merchant function, selling gas from its own inventory, is not the utility's main business. The utility's main business is moving gas, and only to the extent that it promotes transportation of gas should the utility actually be concerned about selling its own gas.

Given these fundamental changes in the industry's setting, what choices does a state regulator actually have?

It may be helpful to mention one option I believe is foreclosed. It is no longer possible to regulate with a "business as usual" mentality, assuming comprehensive, wall-to-wall regulation. As federal wholesale regulation diminishes, so does the basis for this approach. Federal regulation purported to guarantee future supply, current deliverability, and price stability. It encouraged the belief that customers would not change their use in response to price change. It minimized the need for system planning by retail utilities.

Before considering other options, it may also be helpful to identify realistic state regulatory goals. This set might have the support of most regulators: Protect users in monopoly markets (if they really are); promote the business climate for competitive markets; and let Goals 1 and 2 produce healthy utilities. These goals can be translated into slightly more concrete regulatory strate-

gies: Regulate to stimulate competition wherever possible, and where competition is inadequate, regulate to simulate it. This last strategy ordinarily involves using classical rate-of-return regulation to price in monopoly markets. Stimulating competition may be approached either by streamlining the regulatory process for competitive sectors or by isolating and deregulating competitive services by accounting separations, depending on the degree of integration between the monopoly and competitive sectors.

Where can state regulators go from here? A state has two directions it may choose. It may want to recombine the unbundled services to preserve or re-create the monopoly. This option would look a lot like business as usual: traditional retail rates for delivered gas service. The regulatory commission takes on the role of pressuring the LDC to lower system gas cost using all sources available to it. It will have to scrutinize the utility's gas purchasing. The PSC can also expect considerable pressure for special deals in marginally competitive situations.

Can it work? A state may not be able to control physical bypass by interstate pipelines; if not, the monopoly is unalterable. The energy market may be too strong to resist if the regulators attempt to use the monopoly to impose any significant rate design shifts. This option may be more easily achieved if there are no pipelines in the state which have opened under Order 436.

This option describes the current situation in most states. It may be an intentional policy because of inflexible statutes or court decisions. No commission can be expected to go beyond the tolerance of its legislature or its high court. Gradualism may be another reason for following this option for some time. It may provide a status quo while a new program is developed. Does this option do anything to control gas costs? An LDC under this program will have incentives to ignore gas cost to its monopoly market (that is, the cost of gas delivered to the customer, consisting of gas cost plus transportation and distribution costs) and to maximize discrimination, presumably along economically sound Ramsey pricing principles.

A state's second choice is a Mini-436 program, or as Arlon Tusing calls it, service à la carte. This option takes the view that the future of the LDC lies in providing a menu of services responsive to competitive market pressures and to the needs of diverse customers. For "monopoly" or firm service customers, the
LDC can act as buyer, transporter, peaking agency, and risk taker. For other customers, it may provide firm and interruptible transportation, standby, peaking, storage, seasonal, and balancing services. Some distributors may also provide energy management, efficiency, and conservation services.

A Mini-436 program has three parts. Transportation is the monopoly service with the universal obligation to serve. Customers need not buy the utility's gas, but they must know the risk if they do not. Terms and conditions of leaving system gas supply must be clear. Storage, balancing, and other supply management services become stand-alone cost centers. The opportunity for cross-subsidization is reduced.

A Mini-436 program must recognize that natural gas itself is becoming a market-driven commodity, characterized by constantly changing prices and a multiplicity of suppliers. Regulation must allow utilities to react rapidly to price changes. It must also accept, and may come to welcome, additional sources of supply. One can speculate that some suppliers may become quasi-utilities although they lack distribution facilities of their own. Ultimately, it may make sense for gas supply service to be provided under two-part rates—a spot commodity value price and a fixed charge for security. Indeed, it may be said that take-or-pay arrangements have acted as a futures option for firmness of supply.

Whatever pricing mechanisms emerge for gas supply, it seems inevitable that regulated rates will have to divorce gas and nongas costs and perhaps should be separately stated even or customer bills. Only a full separation permits informed customer choices with respect to gas supply options. It will also facilitate regulatory review of utilities' gas acquisition strategies and practices, their planning functions, and their exercise of Order 451 rights.

Can the market-determined price for gas act as a "proxy" for gas prices within the monopoly market? The principle of nondiscrimination says it should. Why should captive customers pay more than those with more options. Alternatively stated, why should regulators, whose objective is to simulate competition where it does not exist, set a price different from that set by competition where it does exist? The difference is that the monopoly market receives a promise of reliable supply. This firmness represents both additional cost and additional value, which differentiates it from spot market gas at any moment.

At the same time, depressed economic conditions can dictate a need for flexibility of price to competitive customers. The focus is on price, not on cost, as Commissioner Schwartz stated earlier in this conference. Allowing some discrimination may be necessary to retain some control of the cost of gas to the captive sector. If regulation holds too firmly to price equality, it may lose significant markets to oil or bypass and thus lose price control.

In conditions nearer equilibrium, however, it would seem proper to avoid discounting. If PGA treatment actually yields zero profit, there is no basis for Ramsey pricing with respect to the gas commodity.

Separate sets of issues arise in pricing gas transportation and in gas sales regulation. It should not be surprising that gas transportation exhibits many of the same characteristics of imperfect competition seen in other once-regulated transportation sectors. Again, the regulatory response should be to stimulate or simulate competition.

Early transportation regulators found several recurring evils: rebates, deferred rebates, fighting rates, control of cargo, and extreme segmentation of markets. They developed several general tools which were more useful than price/entry control alone. The following would be included among the maxims of classical carrier regulation. Rates must be published. They must be strictly adhered to, and no rebating can be tolerated. Instant rate decreases can be allowed if it is made difficult to raise rates later. Carriers may not own cargo they carry or any interest in that cargo. Control of connecting carriers or modes of carriage is suspect. Rates for short haul may not be higher than rates for a longer haul on the same route.

The first years of air carrier deregulation suggest the same tendencies are present in that industry today, and early experience with open transportation by gas pipelines gives reason to believe that this industry may be subject to the same tendencies. Consider whether the pipelines' desire to file actual rates after the fact or the inscrutable complexity of an air carrier tariff are consistent with the open rate maxim. Contrast the negative implications of the pipelines' partial requirements rates or balancing penalties with the more attractively packaged deferred rebate characteristics of the airlines' frequent flyer programs. Air fares from Des Moines, Iowa, clearly exhibit exceptions to the long haul/short
haul principle, and some market area and postage stamp rates serve the same purpose for the pipelines. Examples of market segmentation and fighting rates will readily occur to anyone familiar with either industry.

Regulation of competitive transportation sectors often requires that attention be focused on tariff language or on the effects of rates, not on the level of rates alone. When competitive violations are alleged, evidence often originates outside the regulated firm, not within it. More issues can be resolved by reference to industry standards, or costs, rather than those of the individual firm. Regulators may view their proper role as regulating a marketplace, not its participants.

Regulators will, of course, continue to confront specific regulatory issues. In transportation rate design (including the transportation/distribution element of sales service), these will primarily involve allocation of the fixed costs of the distribution system. Distribution and transportation have relatively low variable costs. First, FERC rate design components (demand charges and commodity charges) have long been combined for state PGA purposes. Attempts to separate and recategorize these charges to meet gas-on-gas competition may raise competition and as-billed arguments at the state level. Second, until there is some standardization of LDC service menus and usage experience, costing of LDC services will be extremely judgmental, because the facilities used for transportation, peaking, storage, seasonal, and balancing services are used in common for several services. Allocation of joint and common facilities costs remains a subject with no easy regulatory answers. Ratemaking volumes must be estimated, and the choice of a base period may become an issue: Should the test period be a year or a business cycle? Should it be a past or future period? Third, the premium for firm transportation over interruptible must be set with recognition of the value of firmness perceived by customers. Perceived value will vary with the degree of utilization and make LDC revenues more cyclical. Fourth, protection of firm customers may require consideration of 100 percent load factor rates or targets through volume dedication. Fifth, with gas prices and the transportation component of sales service unbundled, ratemakers will probably be forced to equalize transportation charges with the transportation component of sales prices. While the non-gas cost of sales service will be the starting point for this calculation,

some elements of the non-gas cost will be treated more properly as fixed costs of firm gas supply. Sixth, transportation arrangements should provide for prompt paybacks where customer-owned gas is delivered to higher priority customers in curtailment situations. Seventh, appropriate balancing requirements need to be found for percent, period, and over/under penalty.

Access questions will arise at the state level involving the same issues faced by the FERC. Non-discriminatory access will remain a vague concept until several problem areas are resolved. (1) Capacity constraints provide an overall limitation on service, but within that limitation states may allow LDCs to serve sales customers preferentially or may require them to give firm transportation the same priority as firm sales. The working definition of available capacity may be proposed to restrict transportation access include: “existing customers only”; limitation by source, either to pipeline or producer sales; limitation to interruptible only; or maximum/minimum volumes. An LDC may want to copy the restrictions used by its pipeline supplier. (2) Within any priority category, first-in-time is the probable ordering mechanism. Commissions may soon be confronted with demands to prohibit resale of previously obtained places in the queue. Existence of an after market would enhance the value of transportation commitments. Without that market, such value would revert to the LDC. (3) Use-it-or-lose-it rules have been proposed for most pipeline transportation. As LDCs begin to reach their maximum available capacity, they may propose similar limits. Regulators will have to balance a customer's right to reserve capacity with the possibility that competitors could monopolize remaining capacity. (4) Validation of transportation requests must not become a means for stealing customers.

Designing rates for gas supply service will present very different issues, having to do with the speed, flexibility, and precision with which an LDC can reflect the market-sensitive commodity value of gas in its price. As a preliminary matter, regulators must consider whether the coverage of their statute includes sales by brokers or producers or, conversely, if they have the choice of deregulating the gas supply services of utilities. (1) Tools for gas supply rate design include rapid PGA adjustments, a mechanism to review the LDC's gas acquisition plan, and development of two- or three-part gas supply prices for large gas buyers. (2) Standby
or system supply reserve charges should recover the LDC's cost of maintaining the availability of gas. A regulatory objective may be to equalize these charges with the premium for firm gas supply. These charges may, however, be time segmented if the firmness is for a limited period or season. (3) The cost causation of past take-or-pay amounts seems certain to be an issue at the LDC level as well as in pipeline cases. (4) Gas supply charges must set the premium for firmness at realistic levels based on customer perceptions. (5) State regulation and tariffs should spell out the rights of a "prodigal" customer attempting to return to system gas purchases after switching to another source. It may be enough to state that the right to return depends on the LDC's situation at the time, or it may be necessary to develop a specific charge to compensate the LDC for maintaining the availability. The risks should be made clear to customers from the outset of a transportation program. (6) Provisions may be needed for customers terminating contractual purchase commitments.

One of the FERC's objectives in the development of Orders 436 and 451 has been to push responsibility for gas supply away from the pipelines and itself and toward the LDCs and state commissions. The movement cannot be arrested, and state regulators will be forced to make decisions of long-term consequence to the structure of the gas utility business in their respective states. With reasonable information and analysis, states are responding to the challenge and should welcome the opportunity to fashion a workable, modern regulatory scheme for the gas industry.

Note

1. The principle of nondiscrimination has two dimensions. First, regulated rates may not give preference or prejudice to the commercial welfare of others. Second, there should be no unreasonable difference in the regulated price for like and contemporaneous service.

Transportation Pursuant to Traditional Section 7(C) Certificates versus FERC Order 436: New Potential for Discrimination against Captive Customers

Thomas C. Gorak

In October 1985 the Federal Energy Regulatory Commission (FERC) promulgated its now famous, or perhaps infamous, Order 436. The rule was issued in response to an order by the U.S. Court of Appeals for the District of Columbia Circuit, which upheld a challenge to two FERC authorized gas transportation programs: the Special Marketing Program (SMP) and the blanket certificate program. According to the FERC, Order 436 was intended to remedy the discriminatory nature of its past gas transportation policies and to promote competition in the natural gas industry by providing nondiscriminatory access to pipeline transportation services. For the first time, any customer of an interstate pipeline would be able to negotiate directly with producers for market-priced gas and to have that gas transported via the pipeline. No longer would firm customers, such as local distribution customers (LDCs), be restricted to purchases from the pipelines' overpriced...
system supply. Promulgation of the rule was an apparent victory for residential customers, who prior to this time were unable to have competitively priced gas transported over the interstate pipeline system.

Despite these apparent “moral” victories, residential customers have not yet received the benefits envisioned by Order 436. Recent reports concerning gas prices illustrate that industrial customers continue to enjoy declining gas prices, while residential consumers continue to pay prices well above market level. For example, recent studies by the American Gas Association show that gas prices for industrial consumers have declined dramatically over the past two years: from $4.35 per MMBtu in July 1984, to $4.13 per MMBtu in July 1985, to $3.45 per MMBtu in July 1986. Residential gas prices not only have remained substantially higher than industrial prices but have declined only slightly since the advent of Order 436: from $6.95 per MMBtu in both July 1984 and July 1985 to $6.77 per MMBtu in July 1986. The Energy Information Administration reports similar figures: In 1986 the average price for gas purchased by industrials declined 24.8 percent, while residential gas prices declined only 6.7 percent.²

These figures graphically demonstrate that the competitive environment envisioned by the original Order 436 has not yet materialized. Instead, interstate pipelines pursue strategies that allow them to continue their past practice of segmenting their markets in order to maximize monopoly profits. As a result, LDCs are unable to obtain the necessary capacity in interstate pipelines to transport low cost gas purchased directly from producers or other nontraditional sources for the benefit of their customers. These disappointing results are due to an apparent retreat from Order 436 brought about by a change in the membership of the FERC. Abandoning the objective of true nondiscriminatory access to pipeline transportation service, this “new” FERC, under the auspices of Section 7(c) of the Natural Gas Act (NGA), has in essence reinstituted the discriminatory transportation programs of old.

The current commission’s failure to adhere to the principles of Order 436 has serious repercussions for residential consumers. They have been unable to participate in the Order 436 program in a meaningful fashion and are in much the same position now as they were prior to it. LDCs continue to purchase pipeline system supply gas at above-market prices for want of a better alternative. This paper explores the “new” potential for discrimination against residential customers through the use of traditional Section 7(c) certificates.

A Brief History

In 1984 the Maryland People’s Counsel (MPC) brought suit in the U.S. Court of Appeals for the District of Columbia Circuit challenging the FERC’s authorization of the SMP and the blanket certificate transportation program. These allowed industrial customers with the ability to utilize an alternate fuel (usually oil) the opportunity to negotiate directly with producers for supplies of gas at a cost well below that of a pipeline’s system supply and to have that gas transported over the interstate pipeline system. However, LDCs which primarily serve residential consumers were barred from participating in the programs and thus were unable to purchase market priced gas. Indeed, the LDC had but one choice: purchase of the pipeline’s system supply gas at prices well above a market level. In this way, the pipelines were able to segment their markets, charging supracompetitive system supply prices to captive customers (residential and small commercial) who could not leave the system, while continuing to collect transportation revenues from fuel switchable customers.

MPC argued that these transportation programs were both discriminatory and anticompetitive and thus demonstrated a classic abuse of monopoly power. In 1985 the court agreed with these contentions in a series of opinions known collectively as the MPC cases. The court overturned the SMP and blanket certificate programs, finding them to be both “unduly discriminatory” and “anticompetitive.” Moreover, the court found that transportation programs involving low cost sales gas could not be limited to fuel switchable end-users but must be offered to LDCs and other captive customers on nondiscriminatory terms.³

In response to the MPC cases as well as changing conditions in the marketplace, the FERC promulgated a regulatory scheme to replace the SMP and blanket certificate programs—Order 436. The analysis contained in that order demonstrates the necessity and wisdom of providing LDCs and other captive consumers with non-discriminatory access to market-priced gas.
Among other things, the FERC found that existing pipeline transportation programs such as the SMP and blanket certificate programs violated the NGA because they were unduly discriminatory and resulted in rates and charges to consumers which were "unjust and unreasonable."6 Moreover, the FERC observed that pipeline companies had exercised monopoly control over their facilities in order to protect or gain advantages in the marketing of natural gas and that these practices had severe effects in "causing unnecessarily high energy costs to consumers and a very large loss to the American economy in jobs, production, and net economic efficiency."6

Nondiscriminatory access to transportation services was described as the "cornerstone" of the rule, and the FERC established the terms it believed were essential to ensure such access. First, a pipeline desiring to offer transportation services was required to offer both firm and interruptible service. Second, a pipeline's firm sales customers were given the right to use that pipeline capacity which was previously reserved for their existing firm purchases for the transportation of gas purchased from third parties. This option, known as the contract demand (CD) conversion/reduction option, was described by the FERC as both "essential" and "indispensable" for meaningful access to transportation services for captive customers.7 However, it is also important to note that the FERC did not require pipelines to provide Order 436 transportation services; it left that decision to the business judgment of the pipelines.

Immediately following the promulgation of Order 436, it appeared that captive customers would be able to participate in the competitive gas market and, thereby, obtain the lower cost gas supplies which had previously been denied to them. Discriminatory programs such as the SMP and blanket certificate program were declared illegal, and Order 436 assured residential consumers that they would have access to transportation capacity on the interstate pipeline system to the extent such capacity was made available to others. In light of Order 436, pipelines had two options. One, a pipeline could remain as a "merchant only"—the "traditional" pipeline role—and determine the price of its system supply gas to all customers in order to keep fuel switchable customers on line. Two, in addition to its traditional merchant function, a pipeline could provide nondiscrimi-
discrimination. Thus, it appeared that applications which proposed to perpetuate the types of undue discrimination or preference eliminated under 436 would be denied. 10

Despite these statements, pipelines began to utilize the Section 7(c) mechanism to do far more than isolated merchant-related transactions. They filed Section 7(c) certificate applications which, in essence, requested authority to resurrect the SMP and blanket certificate programs. Indeed, these requests differed in name only from the former programs; the pipelines again proposed to provide transportation services to their fuel switchable industrial customers while either specifically or practically barring LDCs from obtaining similar services on behalf of retail customers and other customers.

At first it appeared that the FERC would not allow pipelines to sidestep Order 436 through the use of these individual certificates. For example, in a case involving the ANR Pipeline Company, the commission was presented with a group of applications filed pursuant to Section 7(c) which requested authority to transport gas for a number of end-users, excluding LDCs. The FERC denied temporary authorization for the transportation service and set the case for hearing, stating that Order 436 and its underlying rationale required the FERC to assure itself that it would not be permitting undue discrimination or preferential or discriminatory treatment of LDCs. The filing of separate Section 7(c) certificate applications. The commission decided that even though filed on a "piecemeal basis," such applications should be considered as interrelated parts of a larger "de facto" transportation program. 11

This decision bolstered the view that the appropriate use of Section 7(c) certificates was as an adjunct to a pipeline's merchant function, and that the FERC's position to the principles espoused in Order 436 was intact. However, at about this time, important changes took place in the membership of the commission. Chairman O'Connor, a strong supporter of open access, nondiscriminatory transportation and Order 436 resigned, as did Commissioner Georgianna Sheldon. They were replaced by two new appointees, C.M. (Mike) Naeve and Charles A. Trabardt. Almost immediately, the "new" commission began the retreat from Order 436.

On February 14, 1986, in a stunning reversal of its announced policies, the FERC granted the Texas Gas Transmission Corpora-

tion a certificate, pursuant to Section 7(c), to provide interruptible transportation service to 52 fuel switchable end-users who, prior to Order 436, had received the same service pursuant to either the blanket certificate or SMP programs—the very programs terminated by the court in the MPC cases. 12 While the FERC recognized that it was authorizing "virtually intact" service previously declared to be both discriminatory and anticompetitive, it made a tortured attempt to distinguish the new authority granted to Texas Gas from the former blanket certificate and SMP programs. The FERC found that the 52 applications granted were not unduly discriminatory because Texas Gas "promised" to seek additional authority if other customers requested similar service.

(Of course, the service provided was interruptible service, of little use to firm service captive customers such as LDCs, a fact well documented by the commission in Order 436.) In addition, the FERC observed that the authority was limited to a one-year term, and that Order 436 was a voluntary program. Commissioner Stalon filed a vigorous dissent to the Texas Gas order which will be discussed below.

The Texas Gas decision came as a shock to MPC and other advocates of nondiscriminatory open access. It was clear that under the suspensions of Section 7(c) the FERC had reimplemented the very programs found to be unlawful by the court in the MPC cases and by the commission in Order 436. It was also clear that the commission was well aware of its retreat from the strong policies enunciated in Order 436. At the commission's "sunshine meeting" held on May 4, 1986, Commissioner Trabardt stated that, with respect to the policies and goals of Order 436 at the time of its promulgation, "I honestly believe the policy of that Commission was more to deny alternative transportation... . And I think we reversed that position on February 26, with Texas Gas." 13

MPC filed an application for rehearing of Order 436 based upon the FERC's apparent reversal of that order in the Texas Gas decision. In response, on March 28, 1986, the FERC issued Order 436D, 14 which held that the Order 436 program was wholly voluntary and that pipelines could choose to participate or not. While recognizing that it was authorizing "virtually intact" service, the same transportation arrangements found to be unduly discriminatory in the MPC cases, the FERC distinguished its order with respect to the Texas Gas proposal on the basis that it was an
"individual" rather than a "generic" order. The commission observed that there were no claims of undue discrimination and that the proposed programs identified the customers as well as delivery and receipt points. Thus, the "new" FERC chose to ignore the thoughtful analysis contained in Order 346 and to relieve the pressure on pipelines to accept that order by allowing them to resurrect their own discriminatory transportation programs.

On May 22, 1986, Commissioner Stalon issued his dissent to both the Texas Gas decision and Order 436D.15 This 76-page document thoroughly dissects the "distinguishing factors" set forth by the majority in Texas Gas and mounts an eloquent defense of the principles and objectives of Order 436. With respect to the FERC’s contention that no party protested the Texas Gas certificate, Commissioner Stalon correctly observed that the NGA placed an affirmative duty on the FERC to determine that a certificate was in the public interest prior to its issuance, even if no opposition to the application was voiced.16 He recognized that the MPC cases required the consideration of the anticompetitive effects of a transportation program prior to the issuance of a certificate and that these considerations could not be deferred to a later time. Regarding the Texas Gas promise to provide similar access to "all comers," Commissioner Stalon noted that the promise was limited to transportation for the customers of Texas Gas only. Texas Gas had, in effect, created its own special marketing program: limiting transportation to existing core market customers, acting as its own broker, and making contractual arrangements with its own producers. Moreover, the Texas Gas application did not permit LDCs to reduce their contract demands.

Finally, Commissioner Stalon addressed the question of whether Order 436 was voluntary and concluded: "I believe the issuance of the Basic Order 436. In his view, in that order, the FERC told the pipeline community that although the program was voluntary, if a pipeline wanted the flexibility to enter into numerous transportation arrangements, it must do so pursuant to Order 436, as no other type of blanket certificate program would be in the public interest. If a pipeline chose to remain primarily a merchant of gas, with transportation services as a relatively insignificant portion of its business, Section 7(c) authority would be available to complement that primary sales function.

But undue discrimination was just as unacceptable under individual certificates as under Order 436 certificates, and choosing the Section 7(c) option did not relieve the pipeline of the necessity of demonstrating that the discrimination inherent in its application was not undue. With respect to the Texas Gas application, Commissioner Stalon concluded:

Clearly, Texas Gas’ application attempted to perpetuate the undue discrimination of past programs by gaining authorization under another statutory vehicle. Merely designating delivery points, establishing volumes, and changing the kind of certificate authority does not change a discriminatory application into a nondiscriminatory application. In fact, Texas Gas sought the kind of transportation program that parallels Order No. 436, but denies to others some of the benefits they would be entitled to in Order No. 436. The Commission spent one full year developing a transportation program that is in the public interest. It did not invite each pipeline to devise a program of its own and to implement it through individual, piecemeal Section 7(c) certificates.17

This eloquent defense of Order 436 had no apparent effect on the "new" FERC. On May 1, 1986, the Natural Gas Pipeline Company of America was granted authority to provide transportation for an interstate pipeline, an intrastate pipeline, and seven end-users without a hearing, and despite a protest.18 As justification for this grant of authority, the FERC found that Natural Gas would make a greater and more economical use of its system, that shippers would obtain cheaper gas supplies, and that producers would market supplies they might otherwise shut in. The FERC also observed that the application was limited to one year and that the proponents failed to make a showing that the proposed service would discriminate against any group of customers. Of course, these justifications are suspiciously similar to the justifications utilized by the FERC to support the original SMP and blanket certificate programs. Also on May 1, 1986, the commission granted authority to the Panhandle Eastern Pipeline Company to provide interruptible transportation to 39 high and low priority end-users who were previously served under the blanket certificate program.

The Southern Natural Gas Company filed similar applications on behalf of some 43 individual end-users. Belatedly recognizing that there might be potential for undue discrimination, the FERC
set a technical conference to explore that possibility as well as to define the term “undue discrimination.”

In ruling on Southern’s applications, the FERC failed to define undue discrimination, although it decided that Southern was not guilty of it. The FERC ultimately issued the certificates but did retract its policy to allow for flexible receipt and delivery points, a minor victory for consumers.

Thus, the question is: Has Order 436 been undermined by Section 7(c)? Perhaps the quickest answer is provided by observing that, in light of the Texas Gas decisions, ANR has petitioned for rehearing of the FERC’s earlier denial of its certificates. It appears that the FERC’s present policy amounts to nothing more than approval of reconstituted SMP or blanket certificate programs. Pipelines are again allowed to deliver markets and provide transportation to a chosen few (usually fuel switchable industrials), while holding other customers, particularly LDCs serving residential customers, hostage to overpriced supply. While pipelines may profess a willingness to allow LDCs to participate in the Section 7(c) programs, they offer neither firm transportation nor the CD conversion/reduction option. These elements were previously recognized by the FERC as indispensable to meaningful access to transportation by LDCs.

The Section 7(c) program eliminates the incentives for pipelines to minimize the price of their system supply gas to meet competition by allowing them to segment their markets, a practice found unlawful in the MPC cases. The failure of the FERC to consider and explain why those Section 7(c) certificates which have been granted comport with its statutory duty to assure that service is rendered on a basis not unduly discriminatory is all the more inexcusable because the FERC itself, in Orders 436 and 436A, explained in some detail why nondiscriminatory access requirements are necessary to cure the anticompetitive concerns highlighted by the court in the MPC cases. Distinctions drawn by the FERC with respect to this “new” 7(c) service are based on the “old” blanket certificate and SMP service are technical and trivial.

The disclosure of names, volumes, and delivery and receipt points does not significantly distinguish these programs from their predecessors; indeed, the same customers (fuel switchable industrials) are served, and the same customers (residential) are excluded.

The Mandatory Carriage Myth

The issue addressed above is whether the FERC has violated the mandate of the MPC cases by “reauthorizing” transportation programs for fuel switchable end-users without requiring nondiscriminatory access to those programs. It is clear that the “new” FERC has gone out of its way to stress the “optional” nature of Order 436 and, through the use of Section 7(c) certificates, has re-instituted the very programs a unanimous Court of Appeals struck down. One of the FERC’s major justifications for the apparent retreat from the principles enunciated in Order 436 is that it does not want to “mandate” common carriage—something it believes is contrary to congressional intent. However, Order 436 does not mandate common carriage—it requires, consistent with the NGA, that pipeline companies offering transportation services must do so on a nondiscriminatory basis. This requirement protects consumers from exploitation, as required by the NGA, and leaves pipelines a choice of whether to offer transportation services.

Conditioning transportation certificate authority on nondiscriminatory access does not compel pipelines to serve as common carriers. Order 436 expands, rather than restricts, pipelines’ options and allows them to supplement their traditional merchant function by also becoming nondiscriminatory transporters. In passing the NGA, the main concern of Congress was to assure that pipelines were not required to function as common carriers. However, nothing in the NGA or its legislative history suggests that Congress desired pipelines to have the authority to transport gas only for customers of their own choosing—such as fuel switchable industrials.

The MPC cases clearly establish that the FERC may deny pipelines the authority to undertake transportation under anticompetitive conditions. The FERC, therefore, also has the authority to permit transportation under such conditions as are necessary to protect the public interest. Order 436 offered a viable choice to pipelines either to be a traditional merchant (with limited transportation service in support of the merchant function), or to be both a merchant and a nondiscriminatory transporter. This choice is consistent with congressional intent.

Pipelines argue that the FERC has coerced them into accepting Order 436 because operating without such authority would
place them at a competitive disadvantage with fuel oil dealers and those pipelines which possess Order 436 authority. This conclusion is both factually and legally invalid. "Merchant only" pipelines can meet competition by lowering their system supply sales price. To the extent they are successful in lowering their price to meet that of competitive fuels, those customers with alternate fuel capabilities will remain on line. Moreover, whether a pipeline accepts Order 436, it faces the same market pressure to keep prices in line with market forces. In reality, the pipelines' complaint is not that they are being coerced to transport gas but that the FERC will not allow them to transport gas on their own discriminatory terms.

Legal precedent supports a similar conclusion. Federal regulation is not designed to insulate pipelines from competition. Moreover, it has been held that economic coercion does not exist if reasonable alternatives are available. The fact that one alternative is less beneficial economically than another does not mean that alternatives were not, in fact, available.

Finally, MPC believes that the common carriage argument was rejected in MPC I and MPC II. The court, in a footnote, clearly indicated that the FERC had the power to remedy past discriminatory and anticompetitive behavior by conditioning pipeline transportation service on the acceptance of open access. Thus, Order 436 stands as a proper exercise of regulatory power to repress past discriminatory behavior and as an assurance that all consumers will benefit from transportation programs in the future.

The Future for Captive Customers

In the three MPC decisions, the court vacated the FERC orders which authorized pipelines to transport low cost gas for fuel switchable end-users under the SMP and blanket certificate programs. In response to the court's mandate, the FERC issued Order 436, which generically authorized transportation under Section 7(c) of the NGA for all classes of customers, promising meaningful nondiscriminatory access to transportation for firm captive customers. As has been demonstrated, the FERC's current policy with respect to so-called individual Section 7(c) certificates violates both the mandate of the court and the NGA by authoriz-
tomers. Legislation directing the FERC to mandate contract carriage, including a provision similar to the conversion/reduction option of Order 436, may become much more attractive to the new Democratic Congress.

The residential customers' ultimate goal has remained consistent from the time of the initial challenges to the SMP and blanket certificate programs to the present. These customers seek meaningful access to competitively priced gas supplies. Attainment of this goal turns upon the ability of LDCs to obtain access to firm transportation capacity on the interstate pipeline system. Order 436 concluded that this access was required by the public interest and that denial of such access was both discriminatory and anticompetitive. Yet, the FERC's commitment to these goals has weakened, resulting in the resurrection of transportation programs which effectively preclude meaningful participation by LDCs. If residential customers are to achieve their ultimate goal, there must be a rededication to the policies and objectives set forth in Order 436. As in the original MPC cases, the courts will ultimately determine whether residential customers will enjoy gas prices set by market forces.

Notes

1. Maryland People's Counsel v. FERC, 701 F.2d 768 (D.C. Cir. 1983) (MPC I); Maryland People's Counsel v. FERC, 701 F.2d 780 (D.C. Cir. 1983) (MPC II); and Maryland People's Counsel v. FERC, 768 F.2d 453 (D.C. Cir. 1985) (MPC III).
2. As reported in Inside F.E.R.C., p. 5 (10/13/86).
3. See note 1.
5. 50 Fed. Reg. 42,408 at 42,422.
6. Ibid., at 42,421.
7. Ibid., at 42,436, 42,438.
8. Ibid., at 42,435.
9. Ibid.
Gas-on-Gas Competition, Reservation Charges, and Discount Tariffs: The Impact on End-Users

William H. Penniman

In large measure, today's debates over natural gas rate structures and gas-on-gas competition are another unfortunate byproduct of the Nation's 25-year misadventure with wellhead price controls. Despite the Natural Gas Policy Act of 1978 ("NGPA"), the ghost of the U.S. Supreme Court's Phillips decision still haunts the gas industry in the form of rate and investment distortions. Ultimately, the last remnants of the Phillips-generated rate and market distortions will be exorcised only through intense gas-on-gas competition, significant reforms of rate structures, and, quite possibly, some utilities being required to write off investments in capacity that is no longer economically justified.

Overview of the Gas Industry's New Economic Environment

Background

In the second third of this century, the natural gas industry mushroomed in order to deliver an oil exploration byproduct to new markets that could use it. The commodity was cheap, but the new long pipelines and sprawling local distribution systems needed to deliver it were not.

Based on the premise that the emerging interstate pipeline industry had natural monopoly characteristics, Congress responded to the potential for monopolistic behavior by enacting the Natural Gas Act of 1938. The NGA established the Federal Power Commission (later replaced by the Federal Energy Regulatory Commission, FERC) and authorized it to regulate the facilities, rates, and services of natural gas companies engaged in interstate transportation and interstate "sales for resale" of natural gas. Under the NGA, interstate pipelines' regulated rates and tariffs must be "just and reasonable" and not "unduly discriminatory." Production and gathering of natural gas are exempted by the NGA from federal regulators' direct authority, as are rates charged by intrastate pipelines for direct sales to gas consumers. The NGA also leaves intrastate pipelines and local distribution companies LDCs to be regulated by the states.

Local distribution companies and intrastate pipelines have generally been regulated by state or municipal authorities to the extent that they engage in sales or transportation of natural gas for the benefit of the general public. LDCs are typically regulated as public utilities with defined franchise areas, and their rates and services are subject to regulatory approval. In general, LDCs' rates are subject to statutory requirements that parallel the NGA's requirements for interstate pipelines, that is, LDC rates must be just and reasonable and must not unfairly discriminate among similarly situated customers or classes of customers.

In regulating the rates of natural gas pipelines and local distributors, federal and state regulators have generally had to balance several fundamental realities, five of which are identified below.

First, pipelines and utilities are merchants who are offering to sell natural gas and various services that consumers do not have
The economist reasons that, so long as customers who use gas at the peak are charged rates that fully reflect the cost of the facilities, new facilities will be demanded only when the potential recipient of peak service values them enough to pay the full cost associated with the service rather than conserving or utilizing cheaper alternatives. Conversely, if rates underprice service at the peak, then peak demand will inflate, creating pressure for the construction of additional, costly but underpriced delivery capacity. Correspondingly, to the extent capacity costs are imposed on off-peak consumption, off-peak usage will decline as customers respond with efforts to minimize their costs. However, because the off-peak capacity already exists and can be made available off-peak at no cost other than variable costs, it is inefficient to charge rates that drive customers to alternatives which entail costs greater than the variable costs of delivery. The net result of these which unnecessarily drive customers from use of installed capacity is that society will not benefit from maximum productive use of its economic resources.

Fourth, ratemaking is subject to various legal restrictions. In general, a pipeline or distributor must be afforded an opportunity through reasonable rates to recover its costs (including a reasonable return on investment) attributable to prudent expenses and prudent investments that are "used and useful" in rendering the regulated service. This does not mean, however, that utilities are guaranteed cost recovery or that they are entitled to charge ever higher unit rates to collect costs from shrinking markets. Furthermore, rates and services must not be "unduly undiscriminatory," that is, similarly situated customers and classes are entitled to receive comparable services at comparable rates. Within these broad guidelines, regulators have considerable discretion to allocate costs among customer classes and to structure pipelines' and distributors' rates.

Fifth, given the subjective, policy content of the applicable legal standards, ratemaking is inevitably influenced by political pressures and by regulators' own social and political philosophies and objectives. In contrast to the economist's model of imposing all fixed capacity costs on peak markets and maximizing utilization of facilities in off-peak periods, the political agenda of the last 35 years has generally called for shifting fixed costs from peak to off-peak markets, that is, from temperature-sensitive residential
and small commercial customers to industrial customers. Many rationales have been used to achieve the politically desired rate results, such as, making industrials pay their “fair share”; “protecting residential”; and discouraging industrial usage during gas supply shortages. In some jurisdictions, cost-based ratemaking has been overtly supplanted by the idea of maximizing revenues from large customers for the benefit of small customers—in effect, government use of monopoly power to achieve political goals. Yet, while political and social philosophies have been largely responsible for shifting rates to off-peak markets, the Philip decision made that cost shifting possible.

Effects of the Philip Decision

The Supreme Court’s ruling in Philip was ultimately responsible for three major market distortions. Two are still with us and will haunt the gas industry for the next several years.

First, the interstate gas shortages of the 1970s were the most obvious product of the Philip case. Wellhead price controls led to the underpricing of natural gas as a commodity in interstate markets; that, in turn, produced a corresponding increase in demand for gas and a reduction in resource development. The inevitable result arrived in the 1970s: widespread service curtailments in the interstate market. Despite its wrenching transition, the NGPA’s deregulation of the wellhead price for most natural gas supplies should have resolved at least this problem identified with the Philip decision.

Second, rate tilts resulted at the state and federal levels. Suppression of wellhead prices made it possible for regulators to increase pipelines’ and local distribution companies’ charges for service to high load factor industrial markets without risking immediate load losses to petroleum-based alternate fuels. That is, with the commodity cost of gas set at artificially low levels, an additional increment of fixed costs could be shifted to industrial customers while still maintaining a price advantage over at least some major alternative fuels. Since the regulated pipelines and utilities were subject to an overall revenue cap, the effect of raising industrial rates was to reduce residential and commercial rates. At the federal level, this meant that the Atlantic Seaboard rate design method was gradually implemented during the 1980s, and the United rate method was adopted and implemented in the 1970s.

Similar cost shifts from firm, peak markets to interruptible, off-peak markets occurred in many distributors’ rates.

The third distortion was excess capacity expansion. Underpricing of pipelines’ and utilities’ peak capacity compounded the erroneous price signals created by federal regulators’ underpricing of natural gas at the wellhead to inflate demands, particularly in residential and commercial markets. This, in turn, induced additional capacity expansion by distribution companies and pipelines during the 1960s. This occurred even during the 1970s, when supply shortages were widespread. Since residential and commercial markets are characterized by high winter peaks and low off-peak usage, they particularly benefited from both the low wellhead prices and the cross-subsidization of capacity costs by off-peak markets.

While pipelines and distribution companies expanded their peak capacity and distribution networks, pipelines also responded to the growing demand and emerging shortages by (1) extending their mainline and lateral facilities to distant, marginal supplies; (2) expanding gathering networks to reach marginal wells; and (3) investing in costly supplemental supply projects. Ironically, due to the time required for planning, regulatory approvals, and construction, several of these projects did not come on stream until shortly before or even after the NGPA undercut two major factors that justified such projects: cheap wellhead supplies and shortages.

Although some of the exotic supplemental supply projects have now failed and been written off, many of the pipeline and gathering facilities constructed to reach marginal supply sources remain in pipelines’ rates whether or not they are fully utilized today.

Changes in the Gas Market Environment

The economic environment in which pipelines and distributors now operate is very different from the one in which the bulk of today’s facilities were constructed. Now, wellhead prices have been largely deregulated; there is broad competition among gas sellers, including producers, pipelines, distributors, and independent marketers; and in a number of areas even competition among transporters has become a reality.

Demand has responded to the new regime of prices and market signals more strongly than many gas industry officials believed possible ten years ago. Most strikingly, during the past decade, an-
Annual demand for natural gas has fallen by approximately 22 percent, while peak demand remained relatively constant. Demand in industrial markets has fallen particularly sharply, while overall demand in residential and commercial markets has declined only modestly, as is apparent from the following figures:

*Changes in Natural Gas Consumption by Customer Class*

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<tbody>
<tr>
<td>Residential/commercial</td>
<td>– 7%</td>
<td>0%</td>
<td>– 7%</td>
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<tr>
<td>Industrial</td>
<td>– 32%</td>
<td>– 18%</td>
<td>– 16.5%</td>
</tr>
<tr>
<td>Utilities</td>
<td>– 14%</td>
<td>– 11%</td>
<td>– 3%</td>
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Although many factors obviously have contributed to the decline in industrial consumption of natural gas, the disproportionately large decline in industrial demand—4.5 times the percentage decline in residential markets between 1973 and 1985—suggests a lack of demand and gives grounds for concern. Since all consumers, at least until recently, have borne equally the effects of wellhead price increases, one must infer that the rate shifts against industrials and other off-peak users contributed significantly to the disproportionate load declines in industrial markets.

The contribution of rate design shifts to industrial market losses is also suggested by comparing load changes before and after the NGPA was enacted. As the figures above show industrial consumption of natural gas declined sharply both in the five years preceding enactment of the NGPA (– 18 percent) and during the seven years thereafter (– 16.5 percent). In contrast, residential and commercial usage remained constant during the years preceding the NGPA, notwithstanding substantial producer price increases brought on by the Federal Power Commission’s national rate orders. Virtually all the overall decline in residential and commercial markets (– 7 percent) has occurred since enactment of the NGPA. During that period, all markets experienced the combined effects of partial wellhead price deregulation and fixed cost concentration resulting from load losses. Even in the post-NGPA period, residential gas consumption has declined more slowly than has consumption in industrial markets.

*Outlook for the Future*

The gas industry now may face a no-win situation with respect to rate structures and rate design. It must take a hard look at whether any class of consumers can be made to pay for excess capacity for long. Recent experience shows that consumers have limited ability and/or willingness to absorb existing rates, yet price increases. Essentially, all market sectors are now flat or declining. At the same time, natural gas producers have seemingly absorbed all the price reductions possible. The spate of bankruptcies and the low drilling rates during the past few years are ample testimony to this fact. Proved gas reserves have declined in all but two years since 1968. Also, unlike oil markets, the natural gas industry does not have a vast world supply from which to draw. To be sure, Canadian producers have ample reserves which, in theory, could temper the effect of declining U.S. production, but political and practical considerations suggest that these supplies will remain a relatively small component of the U.S. gas mix. As producers’ existing reserves are sold, supplies will tighten, and prices will rise.

If demand is flat or declining at current price levels, the effect of future wellhead price increases is likely to be further demand reductions. Yet, in that environment, any efforts to concentrate fixed pipeline and distribution costs on remaining customers will likely compound the load loss problem, just as it probably has over the last several years. Thus, some pipelines and distributors may have to confront the difficult choice of either writing off substantial capacity costs or facing continuing erosion of load which may pose a greater threat to their long-term financial health. If the latter route is chosen, even generous regulators may not be able to even if willing to save gas companies’ markets and margins from the so-called death spiral of load losses begetting rate increases which in turn beget load losses.

Although writing off investment costs is antithetical to the cost-plus mentality which developed in much of the gas industry during the Phlips era, it is very common in other industries. In private industry, unsuccessful investments are frequently written off or written down. In return for the one-time write-off, the company gains a clean balance sheet, improved earnings on investment, and a generally healthier financial outlook.
Utilities, however, may be particularly reluctant to write off investment. Their regulated rates and maximum potential returns are directly linked to their ratebase, and to write off any portion of it would reduce their maximum potential profits. In contrast to privately operated and regulated companies, a one-time write-off would limit their upside potential for profit, not merely reduce their downside potential. Still, it appears that existing and new facilities must be subjected to closer economic scrutiny than in the past. Cost-plus is no longer a feasible strategy in today's increasingly competitive world.

The Effect of Gas-on-Gas Competition

Notwithstanding utilities' and regulators' reluctance to grapple with the dilemma facing the gas transportation and distribution industry, gas-on-gas competition is likely to provide irresistible pressure to change the services available to consumers and the way rates are established. Pressures for changing service and rate offerings will also be brought to bear by the growing international competition faced by manufacturers who are increasingly forced to cut costs, cut production, and even close plants. Even geographic areas that lack potential for direct gas-on-gas competition will feel the effects indirectly as manufacturers shift production to their lowest cost plants and locate new plants in areas where costs are low.

The power of gas-on-gas competition is obvious from recent experience with wellhead prices. As a surplus of deliverable supplies has persisted for several years, natural gas producers who lack enforceable long-term contracts to sell gas at high prices have aggressively competed with buyers through price reductions. Wellhead prices have dropped sharply as a consequence. On a national basis, average wellhead prices declined from a peak of $2.71 per Mcf in February 1984 to $1.82 per Mcf in October 1986. By late 1986, spot market prices had dropped to as little as $1.00 to $1.40 per MMBtu in major producing areas, although there has naturally been some increase during subsequent winter months.

Long-term contracts with producers will also be affected by gas-on-gas competition. Assuming that buyers have learned anything in the last five years, future "long-term" contracts for the sale and purchase of natural gas at the wellhead will include provisions that allow the parties to reestablish prices and volumes on a regular basis. That is, rationally structured "long-term" contracts will enable either buyer or seller to insist on frequent price renegotiations and changes in take levels. Only in that way can...
buyers under "long-term" contracts remain competitive in resale markets as conditions change.

The excess of capacity relative to demand on most pipeline systems has prompted interpipeline competition to a greater degree than in the past. For the first time in years, interstate pipelines have actively sought to add new wholesale and direct customers. Likewise, where markets are served extensively by two or more pipelines, the ability of wholesale customers and end-users to shift quickly among suppliers has strongly pressured a number of reluctant pipelines to offer open transportation services and lower rates. The power of this competition is evident from the fact that the only pipelines that have thus far refused to offer nondiscriminatory transportation, at least on an interim basis, are regionally isolated and lacking in substantial interpipeline competition. Gas-on-gas competition among pipelines has been frustrated by various orders of the FERC. Steps it has taken include (1) reduction and elimination of commodity minimum bills and minimum take requirements, (2) authorization of self-implementing transportation under Order No. 436, (3) permission to construct, on a nonjurisdictional basis, facilities used solely to transport gas under NGPA Section 311, and an apparent policy to encourage competition through prompt approval of certificates of public convenience and necessity under NGPA Section 7.27.

As with competition at the wellhead, consumers have benefited greatly from the emergence of interpipeline competition. First, as noted above, several reluctant pipelines have been induced by competition to offer transportation services on a nondiscriminatory basis so that users and distributors can purchase cheap gas supplies at the wellhead. Second, several distributors who previously had only a single source of supply, have been enabled to hook up with new pipeline suppliers. Third, some pipelines' rates have been reduced and some rate increases forestalled which would likely have been sought in the absence of competition. Fourth, efforts to hold down rates and improve service have enhanced the overall utilization of the natural gas supply network. That is, the lower rates and better services have helped attract or retain load that would otherwise go to alternate fuels. Gas has even become competitive with coal in some markets. The large savings from transportation of self-help gas have also kept some plants open. Thus, interpipeline competition has not merely involved a struggle to divide a fixed quantity of gas demand; it has helped to retain load and attract new demand as well.

More recently, gas-on-gas competition has begun to emerge even at the level of retail delivery services. In some states, distributors have begun to compete among one another for loads. Where geography permits, some users have constructed private lines connecting their plants directly to wellhead supplies. In addition, direct services by pipelines to end-users—so-called bypass proposals—have begun to emerge.28

Despite some movement, however, meaningful gas-on-gas competition at the local level has been delayed. In part, federal regulators have only recently begun to recognize the potential benefits of pipeline-to-distributor competition and the load losses that interstate pipelines have experienced as a result of distributors' delivery margins. More significantly, however, state regulators and distributors have attempted to interpose significant barriers to such competition, even when it is permitted by franchise laws. In this regard, state and local regulators have often developed a symbiotic relationship with the monopolies under their charge. In a sense, the local distributors' monopoly power has become a base for the regulators' political power. That is, local regulators' ability to achieve the politically popular goal of holding down residential rates has been directly linked to their ability to shift costs to a "captive" industrial market. If that market ceases to be "captive," then the local regulators must either impose the fixed capacity costs on the peak markets (where they properly belonged in the first instance) or on the shareholders of the regulated entities which constructed the now underutilized facilities.

From a broad economic perspective, there should probably be few, if any, barriers to direct hookups by pipelines to end-users. As with other levels of the system, competition should help yield higher throughput, innovations in services, and more economically efficient rates. Direct hookups also offer the potential for lower costs to manufacturers, improved competitiveness, greater productivity, more jobs, and a healthier economy. Furthermore, local distributors, which have existing, partly (or fully) depreciated connections to users which can offer a variety of unbundled services, should be able to compete with new suppliers if they choose to do so. In contrast, treating industrials merely as captive sources of revenue is harmful to the economy at large and may
ultimately be self-defeating as burdened industrials gradually find subtle ways to get off the system anyway. Unfortunately, the fact that helping industrials reduce their costs will help promote the local economy and jobs often seems less important to regulators than achieving more visible, short-run rate subsidies to residential and commercial constituencies.

Regardless of whether bypasses actually become widespread, merely developing a credible bypass potential may create the necessary pressure to reform a distributor's retail rates and services. That is, a serious threat of gas-on-gas competition over direct deliveries to users should help induce distributors to head off the threat by offering a greater variety of services and rates that are closer to costs. Since, in my experience, most users would prefer to stick with their existing distributor if they are treated well, distributors should be able to compete effectively for most users' loads, provided that they try. In doing so, they may also succeed in attracting new customers to their systems.

Two Rate Tools: Reservation Charges and Discount Rates

The FERC has begun to recognize the nature of the situation facing the gas industry. In addition to identifying the problem of decreasing utilization of off-peak capacity while peak usage remains high, the FERC in Order 436 recognized that rates play an important economic function beyond simply collecting money for the pipelines and utilities. According to the FERC, (1) rates should "communicate clear market signals to all participants in the gas industry"; (2) "the pricing system should embody strong incentives to minimize costs"; (3) "customers should be given maximum flexibility in making choices among services and suppliers"; (4) "peak rates should ration capacity and off-peak rates should maximize throughput"; and (5) the basic "framework should apply equally well to different market conditions" without a spate of ad hoc adjustments over time.79

In discussing rate structures for transportation services under Order No. 436, the FERC identified several tools for achieving these objectives. While it left much to be developed in individual cases, rate possibilities included reservation charges, selective discounting of rates, seasonal rates, rates based on distance, and unbundling rates and services into their individual components.

Two of these concepts—reservation charges and discounting—will be discussed below.

Reservation Charges

Reservation charges have long been part of interstate pipelines' firm wholesale rates, and the FERC has recognized them as a legitimate transportation component under Order No. 436. In contrast, they have no place in rates for interruptible services, since neither reliable supplies nor capacity are reserved for interruptible services.

Basically, the underlying concept is that customers who reserve firm capacity or services should pay all or part of the fixed costs, irrespective of whether the capacity or services are fully utilized. To achieve this result, fixed capacity costs attributable to the firm service are typically collected through monthly or annual charges based on the maximum level of reserved services. Variable costs (and possibly a portion of fixed costs) are collected through "commodity charges" in accordance with the customers' actual use of the capacity or service. The result is a two-part rate structure which yields lower average costs for high load factor customers than for low load factor customers.

Various considerations underlie the use of reservation charges for firm services. (1) Most obviously, there is the concept that customers should fully pay for what they get. Firm customers who tie up capacity do so at the expense of both the utility, which must construct facilities to assure continuity of service, and those customers whose access to firm service is limited by existing firm customers' prior claim to capacity. (2) To the extent costs are collected from firm customers through reservation charges, the seller's firm commodity charges and its rates for off-peak and interruptible services can be reduced and still afford the utility an opportunity to meet its revenue requirements. (3) By differentiating between firm and interruptible services, reservation charges can perform a critical capacity allocation function. (4) From the utility's vantage point, reservation charges reduce market risks by guaranteeing fixed cost recovery at least temporarily, that is, between rate cases or until contract demand levels are changed. This risk shifting feature has a negative side to the extent it reduces the utility's financial incentives to maximize use of its system and to minimize its variable costs (such as gas costs).
reduce the fixed capacity costs assigned to a pipeline's commodity charge, its "modified fixed/variable" ("MFV") rate design is jerry-rigged to prevent assigning capacity costs to lower load factor customers in proportion to their responsibility for system peaks. Under MFV, all the pipeline's return on equity and related taxes associated with its investment in transmission and storage capacity are collected through the commodity charge. The remaining transmission and capacity fixed costs are collected through a two-part reservation charge. Within that charge, half the fixed costs are collected based on peak day (D-1) demands and half based on "annual" (D-2) demands. Overall, significantly less than half the pipeline's capacity costs are collected from firm customers based on their reservation of peak capacity. The two-part demand charge thus substantially undercuts the formula's unloading of fixed costs from the commodity charge.

To date, the FERC has applied the same rate design structure to both firm transportation and firm sales rates. As a result, for a very low fee, a firm customer can reserve the right to demand uninterrupted transportation up to its full contract quantities on any day of the year, even if it actually ships gas only sporadically. Because the cost of tying up pipeline capacity is substantially less to the customer who ties it up than to the pipeline that constructed the capacity, pipelines' existing wholesale customers have very little reason to release capacity, even if others may have a greater need for it. Hanging on to the capacity for such a low reservation fee represents a cheap insurance policy to supplement the firm service that the customers actually need. The unfortunate results, however, are that end-users and other distributors who would very much like to contract for firm service cannot do so, and markets behind the distributors that currently have reserved capacity are not given the full price signal concerning the value of that capacity.

To compound the capacity allocation problem, the FERC has elevated interruptible transportation rates to the point that they are only barely (if at all) below the rates charged for firm transportation service. The FERC has achieved this result through its so-called 100 percent load factor or fully allocated rate policy. Under this scheme, costs are allocated and rates are designed so that the unit rate for interruptible service is equivalent to the average unit charge that a firm customer would incur if it took service
under the firm rate at full contract volumes every day. Since the
MFV method's commodity and D-2 charges for firm service are
computed using the pipeline's average load factor, this methodol-
ogy "discounts" interruptible rates relative to firm rates only to
the extent that the D-1 component of the firm rate is reduced, on
a per-unit basis, by the 100 percent load factor assumption, that
is, by spreading those limited costs over hypothetical volumes that
are greater than those actually moving through the system.

To be sure, collecting all fixed costs, including a pipeline's
equity return, through reservation charges would raise legitimate
concerns about undermining the pipeline's incentives to minimize
costs. Currently, load losses affect a pipeline's profitability imme-
diately by depriving it of revenues collected through its commodity
charge. As noted above, this is particularly important in the case of
sales rates, since the rate customers pay the pipeline to keep
have strong economic incentives to keep gas costs as low as pos-
able. However, one may be able to provide adequate incentives and
a fair balance of risks while assigning all or most capacity
costs to the reservation charge. This could be accomplished, for
example, by (1) giving customers a unilateral right to reduce their
firm contract levels or convert from firm sales to transportation
on short notice (at least annually) while (2) making it clear that
pipelines could not recover such losses through higher rates in
subsequent cases. By giving customers the equivalent of "mar-
ket out" rights with respect to their firm contracts, customers
could respond to inadequate service or better offers from others
by changing sellers or transporters. If it were felt that additional
incentives were necessary, this could be combined with an addi-
tional incentive rate mechanism linked to its success in achieving
given sales or throughout rates charged (say, a weighted return on
equity). In any event, it appears that the concerns about guar-
anteeing utility revenues could be mitigated with solutions other
than piling fixed costs onto commodity charges.

Apart from the treatment of capacity costs, an important is-
sue not yet fully addressed by the FERC is what to do with a
pipeline's costs of reserving gas supplies if firm sales customers
choose to purchase from other sellers while holding the pipeline re-
ponsible for meeting its full contract obligations. Several pipelines
have requested that they be allowed to flow their take-or-pay costs
directly to customers who have "deficient" purchase levels. They
propose to collect these costs through demand surcharges which
ensure recovery without affecting the competitiveness of the
pipeline's commodity rate. Others have responded that the risk of
take-or-pay exposure gives pipelines a valuable incentive to keep
their sales rates competitive so that customers do not switch to
other sellers. They are concerned that traditional "prudence" chal-
lenge to take-or-pay costs will be ineffective, so that take-or-pay
rate "trackers" will merely operate to inhibit desirable competi-
tion. The answer to this debate will be an important element in
the shape of reservation charges in the future.

In summary, the FERC has been clear in its decision to in-
clude reservation charges in firm transportation as well as sales
rates. However, by underpricing the reservation charge for firm
peak day capacity, the FERC has subsidized existing firm cus-
tomers' claims to capacity and severely undermined the capacity
allocation function of ratemaking. It also has undermined the ob-
jective of cost-based rates since firm customers for whom the ca-
pacity costs were incurred are able to avoid the full costs that are
properly attributable to the firm services being rendered.

Discount Rates

Discount rates have emerged in recent years as a partial "so-
tion" to the competing desires to preserve maximum revenues
from a given customer class while stemming the tide of load losses
created by excessive rates. Although beneficial to the users who
get them, discount rates may have the perverse effect of propping
up excessive rates for similar customers who do not get them.

In Order No. 436, the FERC posited that an interstate pipeline
can selectively discount rates without engaging in undue discrimi-
nation so long as the maximum rates charged are "just and reason-
able" and revenue losses attributable to the discounts are absorbed
by the pipeline's shareholders, rather than other customer classes.
In effect, the FERC is saying that as long as other customers do
not pay higher rates they are not harmed and do not suffer undue
discrimination. This is the ratemaking equivalent of "no harm, no
foul."

The commission's current position represents a significant de-
parture from past precedent. For example, in Transcontinental
Gas Pipe Line Corp., 28 FPC 979 (1962), the FPC rejected a dis-
count rate that was allegedly needed to prevent a wholesale cus-
customer from going bankrupt. It rejected the proposal notwithstanding the fact that the pipeline offered to absorb the full cost of the discount in the hope of increasing future sales to the customer.20 The D.C. Circuit's decision in the Maryland Peoples' Counsel v. FERC cases also raise questions relevant to selective rate reductions and services for alternate fuel capable customers.21

The most obvious difficulty with the FERC's analysis of the discount rate issue is that, as discussed above, the underlying rates themselves—the so-called just and reasonable maximums—begin at too high a level in the case of off-peak, interruptible customers and high load factor firm customers. The real effect of rate discounting, therefore, may be to recapture load or prevent load loss while still preserving cross-subsidies from continued high rates for most off-peak customers. In this way, discount rates may help users with low cost alternatives (for example coal, residual oil, or access to another pipeline) while continuing to prop up overly high margins to other industrial.

Pipelines and LDCs are caught in the crossfire over this issue. They are told they cannot collect fixed capacity costs from the customers who caused their incidence but must attempt to collect them from off-peak markets, the stability of which will erode over time as the utility tries to collect high revenues from them. That is, while discount rates may help retain load that has installed fuel switching capability, users who cannot now get discounts will continue to develop alternatives that can be paid back through use of cheaper alternate fuels or through the discounts that can be commanded once alternate fuel capabilities exist. Since discounts supposedly come out of pipeline shareholders' pockets, discounts are unlikely to be given out until load loss has actually occurred or is virtually inevitable. Yet, once the alternative capabilities are installed, the pipeline's or utility's load will erode and become less and less stable as a higher percentage of customers develop the capability to switch to alternatives on the basis of small price changes.

One can also question whether it is realistic to suppose that, over time, shareholders will truly absorb the revenue deficiency that may be created by selective discounts. Despite its temporarily fierce appearance to interstate pipelines, the FERC has not been terribly hostile to regulated companies over the years; other regulatory commissions have likewise been somewhat protective of their regulated companies. If pipelines suffer revenue deterioration due to rate discounting, the FERC may well find other ways of assuring that a given pipeline's total revenue requirements are met. This could easily be achieved by increasing a pipeline's equity return, for example, in the name of a "risk premium," to reflect added risks in the marketplace. Alternatively, the commission could adjust the volumes used for setting rates (such as billing determinants) so as to offset the potential underrecovery. In dealing with these issues, the nature of the debate in rate cases could easily shift toward whether the pipeline had engaged in "prudent" rate discounting. So long as the commission concludes that the answer is yes, a way could be found to offset the pipeline's losses assuming other market sectors will absorb higher rates.

Thus, further points should be considered here. First, apart from the effect on end-users, underutilization of facilities is inefficient. Society would be better off if users used those facilities at rates equal to variable costs than it would to have users invest in costly alternatives designed to avoid a given utility's high rates. States and communities interested in expanding jobs and their economic bases should consider this reality even if the economic pay-offs cannot obviously be traced to utility rates. However, authorities must be careful not to offer special deals solely to new customers while existing relatively "captive" customers bear heavy burdens that impair their competitive positions and drive them off gradually. Second, to the extent high transportation charges are exacted and producers absorb those costs through lower net back pricing at the wellhead, they will have less incentive to drill for gas. If that occurs, the remaining customers may find their rates going up anyway as lower output raises prices. Third, to the extent pipelines or distributors engage in ratemaking schemes designed to maximize revenues from their industrial markets, they should receive no sympathy when confronted with users' efforts to "bypass" traditional suppliers in order to receive direct services from other sources. While it is questionable whether pipelines' or utilities' monopoly power should ever be afforded regulatory protection from competition, there is certainly no basis for protection designed to prop up rates that exceed the actual cost of providing service to the customer.

In sum, selective discounting of rates is emerging as an important device for retaining load in the face of competition. Neverthe-
The Impact on End-Users

less, selective discounting raises issues about discrimination within the relevant customer class, at least to the extent it functions to postpone more fundamental rule reforms that would benefit all class members.

Conclusion

The emergence of widespread gas-on-gas competition has been the most important development in the natural gas industry during the 1980s. It has affected every level of the gas system and promises to continue to play a central role in the gas industry’s evolution.

To date, the pressure of competition has been felt most directly by producers and pipelines, while consumers, local distributors, and independent marketers have been the principal beneficiaries. In the future, pipelines will perceive even greater competitive pressure than they face today, and the pressure of competition may apply increasingly to local distributors.

As competition has emerged and wellhead price regulation has faded in importance, rate design and cost allocation issues have returned to the spotlight. Fixed capacity costs were easily incurred and easily imposed on high load factor industries when wellhead price controls artificially held rates down and demand up. However, declining throughput and growing competition require reexamination of who can (and should) be made to bear some of those fixed costs today. In this regard, regulators and gas companies must consider not only competition with other gas suppliers and with alternate fuels, but also the international competition among manufacturers which makes cost cutting a matter of survival for many companies.

Service unbundling, targeted discount rates, reservation charges, and shifting fixed costs to firm, on-peak service from interruptible and off-peak service are important elements of today’s debates over future rates of pipelines and distributors. One way or another, rate structures which seemed workable during the heyday of wellhead price controls will almost certainly have to be modified as gas pipelines and distributors grapple with changing markets brought on by growing competition.

Notes

1. In Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954), the Supreme Court ruled that the Natural Gas Act of 1938 ("NGA"), 15 U.S.C. §171, et seq., required the Federal Power Commission (FPC) to regulate prices charged by producers for interstate sales of natural gas for resale. In 1978, Congress enacted the NGPA, 15 U.S.C. §§3301-3429, which, among other things, (1) implemented phased deregulation of wellhead prices for natural gas sold in the interstate market, (2) eliminated a number of the adverse regulatory consequences of interstate sales by producers or nonpipeline resellers, and (3) enabled gas to be transported in interstate commerce by entities that are not subject to comprehensive regulation by federal authorities under the Natural Gas Act. Subsequently, this phased wellhead price deregulation combined with tumultuous world oil markets and ill-considered gas purchasing practices by interstate pipelines to create havoc in gas markets. See William Penniman, "Natural Gas Pricing Regulation: The Market Ordering Problem," 4 Eastern Mineral Law Institute, Chapter 18 (1983). As wellhead price controls have been lifted on most new gas, the distorting effects of wellhead price controls have been reduced but not eliminated.


3. NGA, Sections 4 and 5, 15 U.S.C. §717c and 717d. In addition, Section 7 of the NGA, 15 U.S.C. §717f, prescribes certificate and abandonment requirements to govern both (1) the initiation and termination of services and (2) the construction and operation of facilities for interstate transportation and wholesales of natural gas. Section 7(a), 15 U.S.C. §717f(a), also permits the FERC to order interstate pipelines to attach and serve new local distribution company customers under certain circumstances. However, for the most part, interstate pipelines’ decisions to serve new customers or to offer new services are voluntary.

4. In a few states, gas production and intrastate pipelines are so pervasive that those pipelines have not been closely regulated, at least in the case of direct services to industries.

5. See, generally, Office of Consumers Counsel, State of Ohio v. FERC, 783 F.2d 206 (D.C. Cir. 1986). (But for a settlement, refunds might well have been ordered following remand of this case, however, that would only have occurred six or more years after the original challenges were made to the pipeline’s gas costs.)


7. In order to reduce its costs, each user may pursue any of a variety of marginally less expensive alternatives, including investing in equipment. William H. Penniman
to burn alternate fuels or to reduce fuel consumption; shifting production to other lower cost manufacturing facilities; shutting down plants; and degrading product quality. These are relatively inefficient results from society’s standpoint.


10. See note 1, Penniman, “Natural Gas Pricing Regulation.

11. See note 2.

12. The Atlantic Seaboard method, which dates to 1953, assigns to the pipeline’s commodity charge 50 percent of a pipeline’s fixed costs of transmission and storage capacity, in addition to all variable costs and the pipeline’s fixed gathering and production costs. See Atlantic Seaboard Corporation, 11 FPC 43 (1952). Due to competitive pressures and the belief that selective discounts to specific customers were unduly discriminatory, the FPC was unable fully to implement the Seaboard method even by the mid-1960s. Instead, despite recitations of allegiance to the Seaboard methodology, the commission repeatedly approved departures (so-called tilts) designed to reduce the costs assigned to the wholesale commodity charge. This was done to keep retail interruptible rates competitive with alternate fuels. See FPCs Research Council, Inc., v. FPC, 374 F.2d 842, 852 (7th Cir. 1967); United Fuel Gas Co., 31 FPC 1342, 1347-52, 1352-63 (1964); and Southern Natural Gas Co., 29 FPC 323 (1963).

The United method, which began to be adopted in the early 1970s, assigns 75 percent of the fixed transmission and storage costs to the commodity charge, along with all variable costs and all fixed production and gathering costs. See United Gas Pipe Line Company, 50 FPC 1348 (1972).

Thus, under the Atlantic Seaboard method, less than half the fixed costs of meeting peak demands were assigned to the peak demand charge. Under the United method, less than one quarter of those fixed costs were allocated based on demands for peak service.


15. Department of Energy, Natural Gas Monthly (DOE/EIA-0035(86/11)).

February 1987, p. 58. The underlying data are as follows (in Bcf):

<table>
<thead>
<tr>
<th>Year</th>
<th>Residential</th>
<th>Industrial</th>
<th>Utilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>4,179</td>
<td>8,889</td>
<td>3,660</td>
</tr>
<tr>
<td>1986</td>
<td>4,903</td>
<td>6,757</td>
<td>3,388</td>
</tr>
<tr>
<td>1987</td>
<td>4,333</td>
<td>5,901</td>
<td>3,046</td>
</tr>
</tbody>
</table>

Industrial gas sales actually rose by about 6 percent between 1978 and 1980 and then collapsed after 1981. This temporary increase occurred partly because NGPA section 311 enabled surplus intrastate gas to be transported to interstate markets, but mostly because of sharp oil price increases triggered by political instabilities in the Middle East, including the Iranian revolution. In 1978 crude oil imported into the United States cost $14.67 per barrel. The average price of imported crude rose to $21.67 per barrel in 1979, $33.89 in 1980, and $37.05 in 1981, before beginning to fall in 1982. The average price of imports fell to $26.50 by 1985, before returning to pre-1978 levels in 1986. DOE, Monthly Energy Review—November 1986, p. 51.

16. Between 1963 and 1965, the FERC permitted various interstate pipelines to implement “special marketing programs” that targeted lower priced gas to price-sensitive markets, in particular to end-users who had the ability to switch to cheaper residual fuel oil. The FERC also tolerated discriminatory transportation practices by interstate pipelines under then existing “blanket” certificate authorizations. In 1985, these programs were rejected by the U.S. Court of Appeals for the District of Columbia Circuit in response to charges of undue discrimination. Maryland People’s Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985) (MPC-I); Maryland People’s Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985) (MPC-II); and Maryland People’s Counsel v. FERC, 768 F.2d 450 (D.C. Cir. 1985) (MPC-III).

Following the FERC’s promulgation of nondiscriminatory transportation rules in its Order No. 430, both distributors and industrial end-users began to gain access to cheaper wellhead supplies. Nevertheless, because industry’s producers have generally been more aggressive in pursuing the transportation option, it appears that in many areas of the country industries have still been able to obtain lower priced gas than other customer classes.

17. Cartellizations during the 1970s also would have contributed to pre-NGPA reductions of sales to industrials. However, the large disparity between residential and industrial load declines and the failure of the gas industry to recoup industrial losses after shortages ended suggest that rates had a significant effect on industrial load.

18. As annual load has declined, fixed costs that had been collected from departed customers have been concentrated on the remaining gas users. This has compounded the load loss problems in off-peak markets and raised prices in peak markets as well.
The Impact on End-Users

19. Significantly, the available data contradict the perception that industrial load largely switched to residual fuel oil and thus is available for recapture by gas markets. In fact, residual fuel oil consumption in the United States has also declined sharply since the late 1970s, although it rose in 1986 compared to 1985 levels.

20. A potential alternative to write-offs may be for utilities to vary their depreciation rates in response to changing market conditions. For example, during periods of low throughput or intense competition, a utility might develop rates using a slower depreciation schedule, thereby lowering current rates but raising rates for the future. This allows for a lower return in years when market conditions improve through competitive alternatives, which could potentially be accelerated.


22. There is a lack of symmetry here that is important to recognize: Load is not necessarily regained by price decreases to the same degree that it is lost to price increases. That is, when prices rise, some load is being lost permanently to plant shutdowns, permanent efficiency improvements, and conversions to fuels that are priced below levels with which gas can compete over the long term (such as woodchips). Thus, load recaptured from alternate fuels after periods of price increases may well be less than existed previously.

23. For example, Algonquin Gas Transmission, Florida Gas Transmission, Mississippi River Transmission, and East Tennessee Gas Pipeline. It remains to be seen whether there will be retrenchment by pipelines that have offered interim open access transportation. Some face only limited competition from other pipelines, and the limited number of pipelines exacerbates the risk of consciously parallel behavior to limit competition.


30. See also Otter Tail Power Co., 2 FPC 124 (1940).

31. The MPC cases may be distinguishable from the FERC's selective discount transportation rates since a pipeline implementing an SMP typically absorbs no rate discount of its own. Instead, under the special marketing programs, the pipeline hoped to collect its normal transporta-

32. William H. Penniman
LDC Strategies for Optimizing the Mix of Spot and Long-Term Purchases

John S. Fick

The purpose of this presentation is to discuss some of the current uncertainties faced by local distribution companies (LDCs) as they make supply contracting decisions and describe the approaches being used by the Southern California Gas Company (SoCalGas) to develop its overall gas purchasing strategy that are based on the explicit consideration of these many areas of uncertainty.

An Industry in Transition

The gas industry is currently in the midst of a transition from a gas supply environment which allowed LDCs almost no supply purchasing flexibility to an environment of perceived open competition in which we have very broad purchasing flexibility. I say "perceived" because, at present, we seem to be somewhere in the middle between a system of comprehensive regulation and open competition; some might even suggest that we are struggling with the worst of both worlds. The SoCalGas experience, thus far in this transition, has probably not been dissimilar to that of others.

Prior to 1980, demand on the SoCalGas system exceeded or equaled supply availability, and our gas purchase contracts contained a variety of restrictive provisions. As contract prices increased under the NGPA of 1978 and the supply surplus grew, pressure developed to create contractual and regulatory changes that would increase the gas purchasing flexibility of LDCs. Through a series of negotiations and/or regulatory proceedings, minimum bills and minimum take obligations in our gas purchase contracts with suppliers were substantially reduced or eliminated. This, of course, has contributed to the take-or-pay problems presently being visited upon interstate pipeline suppliers. But without having this initial relief, the transition from a system of comprehensive regulation to open competition could not have begun.

The gas industry transition has been, and will continue to be, spurred on by the implementation of FERC Order 436, which is aimed at moving pipelines toward providing open access to their pipeline capacity, thereby giving end-users greater access to supplies, and by FERC Order 451, a measure that will tend to increase old gas prices; the embedded commodity costs of interstate pipeline supplies; and, the supply of lower cost, nonpipeline gas, which can be purchased directly by LDCs and end-users.

Spot Market Purchases

SoCalGas responded to its newly gained gas purchasing flexibility by establishing a blind bid program for spot market supplies in July 1985. We had hoped for total bids in the neighborhood of 200-300 MMcf/d and were surprised when we received 1.2 Bcf/d in bids. Our actual purchases totaled slightly above 600 MMcf/d in that first month. Since July 1985, spot market purchases have averaged over 28 percent of our total supply. The swings in our purchases of spot market supplies, however, have been quite substantial as a result of variations in our market requirements. In 1986 SoCalGas purchases of spot market supplies ranged from a low of about 400 MMcf/d to a high of about 850 MMcf/d.

The active involvement of SoCalGas in the spot market has, of course, been motivated by the significant short-term cost savings that, so long as the gas supply surplus exists, can be re-
alized by substituting spot market purchases for dedicated supplies. In July and August 1985, the first two months of our spot market program, the average cost of our spot gas purchases was $2.73/MMBtu and $2.67/MMBtu, respectively, significantly lower than the commodity rates of our two major interstate pipeline suppliers, which averaged $3.20/MMBtu during that period. In subsequent months, the price differential between the average cost of our spot market purchases and our pipeline’s commodity rates ranged between 50¢ and 58¢/MMBtu. Our estimates that, compared to the alternative of purchasing commodity rate supplies, our spot market purchases saved our customers about $85 million in 1985 and more than $175 million in 1986.

In addition to direct cost savings, our spot market purchases put considerable pressure on the prices we pay for dedicated supplies. In fact, we believe that spot market prices have contributed significantly to the 25 percent reduction in our pipeline suppliers’ commodity rates experienced since the program was initiated.

I think it is important to make note of the limited reliability associated with supplies purchased on the spot market. Since our spot contracts do not require the seller to deliver its gas upon acceptance of their bid, there will always be uncertainty as to whether the gas will actually be there when we need it on a daily basis. As a matter of fact, our experience since June 1985 has seen nonperformance of around 25 percent. We are concerned that as the gas market tightens, for whatever reason, spot gas supply will become more unreliable and that this will happen precisely when it is needed the most.

**Released Gas and Incentive Gas Programs**

In order to facilitate sales of dedicated supplies that would not otherwise be purchased by us because they are not price competitive with spot market supplies, SoCalGas implemented a released gas matching program under which we commit to purchase a block of dedicated supplies from our major interstate pipeline suppliers at the average price of supplies bid into our spot market program each month. In addition to the obvious benefit of immediate gas cost reductions, the released gas matching program provides the further benefit of mitigating the mounting pressure of our pipeline suppliers’ take-or-pay exposure. In another effort to facilitate sales of dedicated supplies, we have agreed to buy such supplies above minimum bill levels (where they still exist) if those supplies are competitively priced when compared with available spot market supplies.

**The Supply Portfolio Challenges**

The availability of low cost spot market supplies together with major reductions in our contract purchase obligations required SoCalGas to reassess its gas supply policies. Specifically, we needed to examine the trade-offs between the near-term benefits of lower cost spot market supplies and the long-term risks of higher costs and supply shortages that could result from excessive dependence on spot market supplies.

Beyond the challenge of determining the optimum mix of spot and dedicated supplies, it is also necessary to deal with questions regarding the structure of the long- and intermediate-term contracts themselves. This is even more important in the wake of FERC Order 436 because the open access to interstate pipeline capacity required by that order has greatly improved our ability to acquire supplies directly from producers. Issues regarding contract structure can be addressed under the conceptual headings “duration mix” and “flexibility mix.” Contract duration mix involves the use of a range of intermediate- and short-term contracts as a tool to manage supply and price risk. Contract flexibility mix involves the determination of the most appropriate set of contract provisions, such as market-out clauses, reservation fees, and fixed price contracts. If flexibility were free, we would attempt to get as much as possible. Since it has a cost, it is necessary to determine the amount we can afford.

Briefly, then, the challenge is to develop a supply portfolio which includes a broad range of contract durations and structures that minimize purchased gas costs over the longer term. (Please note that the optimum contract portfolio for SoCalGas is not necessarily the most appropriate contract mix for any other LDC.)

**Sources of Uncertainty**

The primary difficulty in developing and managing a supply portfolio is getting a handle on the various sources of uncertainty we find all around us. These include questions regarding future gas supply availability, price and demand levels, underlying economic
trends, and regulatory and legislative changes. While these factors are not strangers to any of us, the ongoing transition in the gas industry is adding an additional degree of complexity to efforts to forecast them.

Price and supply stability, for example, are influenced by spot and pipeline contract price differentials, direct purchase opportunities, dedicated pipeline capacity, and oil market dynamics. Demand stability or growth will be heavily influenced by the unbundling of sales and transmission services, the prevalence of fuel switching, the development of new markets (such as EOR, cogeneration, small electric generation plants), and resolution of the bypass issue. All of those uncertainties may be further affected by future regulatory and legislative initiatives.

SoCalGas is currently involved with a statewide investigation by the California Public Utilities Commission (CPUC) which contemplates multiple supply portfolios and requires the unbundling of gas sales and transmission services and rates to our nonfarm customers. Essentially, the CPUC has separated our market into two basic categories: a core market, consisting primarily of customers without alternative fuel capability (primarily residential and commercial customers), and the noncore market, consisting of customers with alternative fuel capability. Core customers who use an excess of 25,000 MMBtu of gas per year may elect to receive only transmission service. Noncore customers may elect transmission only service, procurement service from spot market supplies, and firm “core elect” procurement from the core market portfolio.

Since the CPUC contemplates further hearings on the gas procurement side of its investigation, many important issues have yet to be resolved. These hearings will undoubtedly consider the following: the specific makeup of particular portfolios, the number and types of portfolios that may be permissible, the degree to which LDCs in California may be held at risk for unrecovered gas costs; the handling of so-called transition costs which will include take-or-pay buyouts by pipelines, to the extent they are passed through to us; the question of bypass; and the further unbundling of services, including storage.

Development of Supply Procurement Strategies

The basic supply strategy of SoCalGas has been to (1) match a variety of significantly different supply sources with the needs and risk preferences of our various types of customers and (2) sequence our gas purchases in a way that stimulates price competition among our suppliers to minimize gas costs. This approach employs the same natural division of the SoCalGas market as adopted by the CPUC in its recent decision regarding transmission service and rate design. As indicated above, that decision divided our market into core and noncore segments and required SoCalGas to serve each from a separate supply portfolio.

Matching Supplies with Customer Risk Preferences

A key factor in our ability to implement this strategy is access to a diverse base of dedicated supplies. The portfolio available to core customers presently includes California state onshore and offshore supplies, gas production from federal offshore areas, Canadian gas purchased through our affiliated interstate pipeline supplier, supplies from major interstate pipelines, and spot market gas. In addition, as a means to balance supply and requirements, SoCalGas operates underground gas storage with a total capacity of about 114 Bcf and a maximum withdrawal rate of 5.4 Bcf/d.

In 1986 about 35 percent of SoCalGas purchases of dedicated supplies were directly from producers or through one of our supply affiliates. This has allowed us to develop a diverse set of gas contracts through which supply and price risks can be managed. Some of those contracts include exchange agreements under which we receive gas from a producer at one point and then deliver gas to the producer somewhere else in our service territory, provided that we do not need the gas ourselves or the producer does not choose to offer it to us. Other contracts require a certain percentage of the gas to be priced at the lower of the commodity rate or the average of our marginal supply purchases. Still other contracts require gas to be priced at our annual or monthly border prices. I might add, as an indication of the supply security offered by these contracts, that most of our contracts with producers cover production over the life of the field.

Recently, long-term dedicated pipeline supplies have been planned, together with the direct purchases described above, at a level sufficient to meet the cold year requirements of our core customers as a means of providing them with long-term supply security. During warm or average temperature conditions, “excess” dedicated supplies would be sold to our larger commercial, in-
dustrial and electric generating customers. This strategy required annual average purchases from our two major interstate pipeline suppliers at a level equivalent to 40 percent of their contract demand quantities (CDQ). However, executing this strategy proved to be quite difficult in warm or average temperature years when excess dedicated supplies could not be sold to nonfirm customers due to price competition from alternative fuels or other gas supplies. In fact, in 1986 our inability to market dedicated supplies to our alternate fuel capable customers forced us to back away from the cold year requirements as the standard for commodity rate purchases. Instead, we are now following a strategy of purchasing only enough dedicated supplies to meet average temperature year core market requirements. We are concerned that this approach puts core customers at risk during cold year conditions. Our ability to provide supply security to our core customers during such periods will probably become even more tenuous in the future, to the extent that our noncore customers choose transmission only service, since they will no longer be available to buy “excess” dedicated supplies in warm years even if those supplies are cost competitive.

Reductions in our purchases of dedicated supplies tend to (1) increase the take-or-pay liabilities of our pipeline suppliers, exposing SoCalGas and its customers to the possible pass-through of those costs, and (2) jeopardize the future availability of those supplies at levels necessary to meet cold year requirements, possibly leaving us more dependent on short-term supplies during such periods. The availability of released gas—dedicated supplies at spot market prices—has helped to mitigate those effects. During most of 1986 SoCalGas was able to market released gas from our major interstate pipeline suppliers to our core customers at a level equivalent to 20 percent of CDQs, thereby increasing our total purchases of dedicated supplies. Most recently, one of our suppliers has taken steps which make it more difficult to purchase released gas on its system. We are hopeful that this will not result in a substantial decline in our purchases from this lower cost source of supply.

Stimulating Price Competition

Our current supply purchasing strategy attempts to stimulate competition among our dedicated pipeline suppliers by sequenc-
market program, we began working closely with DFI to develop in-house expertise in the use of this approach and to make changes in the model necessary to tailor it for use in gas supply decision making. SoCalGas was the first company to apply this model to gas supply portfolio management. I understand that it is now beginning to be used by other gas utilities throughout the country.

The model focuses on the following strategic questions: (1) What are the cost/benefit trade-offs associated with the different types of gas supplies (such as spot, short-, intermediate-, and long-term supplies)? (2) What role should those various supply alternatives play in our supply portfolios?

The model requires supply and marketing planners to characterize the entire range of possible outcomes of the various supply and demand uncertainties over a given planning horizon, together with the associated probabilities of their occurrence. For example, the group that develops the SoCalGas oil price forecast is required to provide three or four possible price scenarios together with the probability of each one materializing.

It is important to note that the process of providing this input is valuable not only as it affects the output of the model but also because it forces managers and planners to think about gas supply issues and the probabilities of alternative outcomes in a disciplined, systematic way. Furthermore, this process requires a more rigorous analysis of the issues at hand than does an approach which simply requires a single forecast with no consideration of alternative scenarios and associated probabilities.

Some of the input variables used by the model are: expected requirements of core and noncore customers; the alternative fuel capabilities of our customers; possible pipeline supply availability and prices (including take-or-pay consequences); spot market supply availability and prices; and information related to the terms and conditions contained in intermediate and long-term contracts. Simply stated, the model integrates this information and tests alternative supply mix strategies under different scenarios by simulating gas purchases from available sources in a manner that minimizes total costs given our existing contract commitments. The model then calculates the costs associated with each supply procurement strategy being considered under a variety of market conditions. The model thus enables supply planners to examine the risks of alternative strategies, not simply the expected costs.

This feature is important because, typically, the differences in the expected costs of alternative strategies may be very close, while the associated risks vary substantially.

For each supply mix and economic scenario under consideration, the model evaluates the total and average unit cost of gas; gas purchases by source; likely levels of gas curtailments; load loss to competing fuels; and takes of gas that minimize purchased gas costs.

It is important to emphasize that by relying on this model we are not replacing management decision-making with a computer. Rather, we are using the model as an aid or a tool in the overall supply management process. We fully realize that any mechanical process is going to have limitations in its ability to consider "all" relevant factors. The model we are using is no exception.

Summary

Today, as we move toward an era of open competition, the future is replete with uncertainties. Our challenge is to recognize those and shape our gas supply portfolios accordingly. It is our hope that by actively developing and managing our diversified supply portfolios, based on a rigorous evaluation of our gas procurement alternatives, we will be prepared to meet whatever circumstances may develop.
I appreciate the opportunity to voice the pipeline point of view on the many issues that constitute the transition of the gas industry—or parts of it—from rigid and comprehensive regulation to a climate where market forces are being encouraged to have increasing influence. The primary difficulty for pipelines in adjusting to the massive changes coming from the market and the regulators involves the fact that the playing field is just not level for all participants, representations to the contrary notwithstanding. Let me explain.

A shrinking market—consumption in 1986 was estimated to be about 20 percent below that of 1981—has created a surplus of gas production. That surplus, in turn, has generated demands by certain producers and LDCs for access to the spot market, where prices are a function of basic economics—supply and demand. Such prices are below those in pipeline gas purchase contracts, where the prices were set by government fiat—FERC regulation and the Natural Gas Policy Act of 1978. Administrer prices and the free market are not compatible, but those are controlling facts in the current gas industry situation.

So, LDCs and their consumer-oriented supporters are saying: "We don't want your contract gas, Mr. Pipeline—we want your transport service to haul us the spot market gas." As we all know, these attitudes have become public policy in the form of Order 436.

The origin of that price disparity is, however, conveniently forgotten or at least given little recognition by the rising chorus that is now accusing pipelines of blocking access. We in the pipeline industry have no difficulty with free market theory. The problem comes in the real world, where contract realities cannot be ignored. In short, the consequence of access is take-or-pay exposure, and that is a financial hazard pipeline management is unwilling to carry alone. Current estimates are that this exposure for the industry is approaching $13 billion, a sum greater than the net worth of the pipeline industry.

More to the point, as far as pipelines are concerned, is the absence of clear regulatory policy dealing with the recovery of the cost of take-or-pay settlement and contract reformation costs. The contracts that result in take-or-pay exposure were, for the most part, signed under the prior regulatory conditions. The volume of gas under contract relates to the pipeline's legal obligation to serve. Those contracts were based upon requirements data provided by the same LDCs which, for the most part, now want to be relieved of their obligation to purchase. This set of circumstances makes the playing field uneven as far as pipelines are concerned.

This financial exposure becomes even more serious when reasonable recognition is given to the uncertainty surrounding recovery of the buy-out costs. My company has endured three prudence inquiries. The fact that we have won each case does not deter our utility customers from raising the same issues again each time a PGA is filed. Fairness requires a more efficient solution.

The material presented by William Smith, Thomas Gorak, William Penniman, and John Fick was deficient in another respect, namely, the absence of comment about security of supply for the long term. It would appear that those who want to re-model the industry have abandoned any concern for supply adequacy, which responsibility pipelines have satisfactorily carried up to this time. As a responsible company with more than half a century of experience, Panhandle Eastern believes it must remind audiences of the need to pay attention to the long-term supply...
question. If experience teaches us anything, it is that current conditions of surplus and relatively low spot prices will not be ever present. As we have seen in oil markets, availability and price are cyclical. What goes down will inevitably go up.

Today's surplus can easily turn into tomorrow's shortage. The physical facts clearly point that out. Gas drilling is down by almost 60 percent in the last four years. Reserve replacement is also lagging consumption. The so-called gas bubble does not have an everlasting life. But by the time the next supply crunch appears—possibly in the 1987–1988 winter—the infrastructure that in the past searched for and developed supply will have been substantially demolished. Prices below replacement costs—the current circumstance—do not attract drilling investment. And with pipelines reforming contracts and getting out of the merchant business, who will be responsible? This is a question that public policy has not yet addressed.

Absent divine insight, I must leave to others to discuss and determine what policy will best serve the long-term interests of consumers. I strongly suggest that emphasis upon “least-cost” purchase practices does not provide the economic incentives necessary to attract investment for the search for reserves. I suggest that the short-term benefits of the spot market are just that—short term, this year, maybe next year. Those who advocate complete market freedom for LDCs have an obligation, it seems to me, to prepare consumers for the tighter supply and higher prices that are surely coming.

There is yet another matter addressed by these papers that merits comment: by-pass. While traditional regulatory concepts are being downplayed in favor of market forces, those advocating allegiance to the market also invoke regulatory protection of LDCs against by-pass. Yet, direct supply relationships with an end-user are, in my opinion, but another expression of the market at work. Those who oppose by-pass, however, assert that the whole stream of utility revenues must be protected in the interest of the so-called captive customer. If that is a valid concern, the philosophy that supports it should also encompass concern for supply adequacy and, therefore, something less than total purchase mobility for LDCs. If pipelines are to compete, certain markets cannot be fenced off. Again, we have the question of defining the attributes that constitute a level playing field.
Part Ten

New Public Utility Accounting and Taxation Issues
The Effects on Public Utilities of the Tax Reform Act of 1986

Donald W. Kiefer

The Tax Reform Act of 1986 has been described as the most significant revision of the income tax since World War II. The act broadens the tax base and reduces tax rates; it also provides a small tax cut to individuals while increasing taxes on corporations. The act will have major effects on public utilities, both because they will be affected substantially by the general revisions in the corporate income tax and because some provisions are directed specifically at the utility industry.

This paper reviews seven provisions in the act which will have major effects on public utilities. The final section briefly discusses the likely overall effects of the Tax Reform Act on utilities.

Note: The views expressed are those of the author and do not represent the position of the Congressional Research Service or the Library of Congress.
Decrease in the Corporate Tax Rate

The Tax Reform Act reduces the corporate income tax rate from 46 percent to 34 percent effective July 1, 1987. The act also includes a provision that, for public utility property, requires excess deferred taxes attributable to accelerated depreciation (the difference between deferred taxes computed using the prior tax rate and deferred taxes computed using the new tax rate) to be normalized over the remaining lives of utility assets as the tax timing differences reverse. The requirement does not apply to excess deferred taxes attributable to factors other than accelerated depreciation, for example, construction period interest and taxes.

The corporate tax rate was reduced from 48 percent to 46 percent in 1978, but no such normalization requirement accompanied that tax decrease, and the issue was not addressed in Treasury regulations. Several utility commissions followed the reduced deferred taxes resulting from that tax rate decrease through to lower utility rates over periods ranging from three to five years.

The normalization requirement in the 1986 act has already become controversial and is likely to receive increased attention. Some consumer groups and state regulatory commissions would like for the excess tax deferrals to be flowed through to lower utility rates. The total amount of excess tax deferrals at the end of 1986 is probably about $9.3 billion in the electric utility industry, $7.4 billion in the telephone industry, and $2.2 billion in the gas utility industry. If these excess deferrals were all flowed through to reduce utility rates over a three-year period, the annual rate reduction would be approximately 2.3 percent for the electric utilities, 2.7 percent for the telephone companies, and 0.9 percent for the gas companies.

The appropriateness of the new normalization requirement can be evaluated using several criteria. In the case of accelerated depreciation, which gave rise to the deferred taxes, these different criteria yield consistent policy conclusions. In the case of the excess deferred taxes resulting from a tax rate decrease, however, the criteria yield different conclusions.

Congress required normalization of accelerated depreciation principally to avoid the tax revenue losses associated with flow through treatment and to assure that accelerated depreciation would have the intended effects in the public utility industry.

The rules regarding normalization treatment are also structured to be consistent with the overall logic of utility rate regulation rather than imposing some different procedure (for example, tax accounting or consistency with the economic theory of income measurement) on the ratemaking process.

Under flow through treatment of accelerated depreciation, tax collections from utilities are lower early in the lives of assets (and higher later) than under normalization treatment. Similarly, flow through of the excess deferred taxes resulting from tax rate reduction would cause tax collections from utilities to be lower in the first several years after the rate reduction (and higher later) than if the excess deferred taxes continued to be normalized. Such a pattern would be inconsistent with the general character of the Tax Reform Act of 1986; most of the provisions of the act were designed to affect the timing of tax payments require earlier payments rather than later.

Congress intended accelerated depreciation to reduce the after-tax cost of acquiring capital assets and also intended the tax saving resulting from accelerated depreciation to be available to finance capital investments. Flow through treatment is not consistent with the second of these purposes since the tax saving resulting from accelerated depreciation is used to reduce utility rates charged to customers rather than to finance capital assets. Similarly, flow through of the excess deferred taxes resulting from tax rate reduction would force utilities to refinance the portion of their capital stock currently financed by the excess tax deferrals.

Hence, consistency with the stated congressional intentions in enacting accelerated depreciation and its normalization requirement would seem to dictate requiring normalization of the excess deferred taxes resulting from tax rate reduction over the remaining lives of the assets. Normalization can also be evaluated against other criteria, however, some of which suggest different conclusions.

One such criterion is the consistency of the required ratemaking treatment with the true economic character of the tax benefit. The effect of accelerated as compared to straight-line depreciation is like an interest-free loan. Normalization treatment of accelerated depreciation is consistent with this characterization; it permits the utility to retain the "principal" (the tax deferral) of the interest-free loan to finance its capital assets while exclud-
ing the loan amount from the utility’s rate base, thus providing customers with the benefit of the zero cost capital.

The reduction of the corporate tax rate would convert a portion of this interest-free loan into a grant; a portion of prior tax deferrals would no longer have to be repaid. This grant is a windfall to the company. The logic of public utility ratemaking, which exists to prevent “natural monopolies” from earning “excess profits” (while enabling them to recover the costs of providing their services and to earn a reasonable rate of return on invested capital) would seem to require that this windfall be used to reduce utility rates. Both normalization and flow through treatment would have this effect.

Another criterion for evaluating the appropriateness of normalization treatment is the distinction between a timing difference and a permanent difference in the recognition of an interest in accounting versus ratemaking accounting. Generally, normalization is regarded as appropriate treatment of timing differences and inappropriate treatment of permanent differences. The difference between accelerated tax depreciation and straight-line ratemaking depreciation is a timing difference which is appropriately normalized according to this criterion. When the tax rate is decreased, however, a portion of deferred taxes which previously represented a timing difference becomes a permanent difference and, according to this criterion, should be flowed through to an adjustment in utility rates.

An additional criterion for the evaluation of a ratemaking process is the degree to which, to the extent possible and appropriate in a regulated industry, it emulates the results which would be expected in the unregulated sector of the economy. In the unregulated sector, the windfall associated with the tax rate reduction on previous tax deferrals presumably will simply increase the profitability of existing assets. Emulating this result would require completely ignoring the windfall in setting utility rates, neither normalizing nor flowing through the reduced tax deferrals. As mentioned earlier, however, since one purpose of utility regulation is to prevent utilities from earning “excess profits,” presumably, the windfall resulting from the tax rate decrease is intended to increase the profitability of utilities. On the other hand, under either normalization or flow through, utilities will not profit from the windfall so long as the excess deferred taxes are excluded from the rate base during the amortization period.

The windfall received by unregulated companies presumably will have no effect on the prices of products produced by existing assets. Emulating this result in the regulated industries also would require ignoring the windfall in ratemaking, which, for the reasons stated above, would be inconsistent with the purposes of regulation. Both flow through and normalization treatment would yield price reductions on utility services as a result of the tax rate reduction. The difference is in the timing and pattern of the price effects. Flow through treatment would concentrate the price reductions in the first few years after the tax rate reduction, followed by price increases resulting from the substitution of private capital for cost-free tax deferrals. Normalization would spread the price reductions over the remaining lives of the utility assets.

Also in the unregulated sector, because the windfall will have no effect on prices of products, the previously deferred taxes will continue to be available to finance capital assets (the tax rate reduction, in effect, converts deferred taxes to equity). Thus, in the unregulated sector the tax rate reduction, in essence, automatically refines existing assets with new equity capital. In the regulated sector neither normalization nor flow through treatment would convert the excess tax deferrals to equity capital, but only normalization would avoid refinancing the portion of utility assets currently financed by the excess tax deferrals.

In adopting the normalization requirement, Congress clearly decided that consistency with its intentions in adopting accelerated depreciation and the normalization requirement as well as attempting (to the extent appropriate) to emulate the results in unregulated markets were the most important considerations in determining the appropriate regulatory treatment of the excess deferred taxes resulting from tax rate reduction.

Repeal of the Investment Tax Credit

The Tax Reform Act repeals the investment tax credit (ITC) effective January 1, 1986. A number of general and specific transition rules permit some property to continue to qualify for the credit. While these will not be detailed here, the general rule provides the credit for property for which a binding contract existed on December 31, 1985, and which will be placed in service by a specified date depending on the property’s depreciation class (for
example, 15-year and 20-year property must be placed in service by January 1, 1991, to qualify for the credit. Tax credits taken on qualified progress expenditures prior to January 1, 1986, are not affected by the repeal. Progress expenditures after December 31, 1985, continue to qualify for the credit so long as the property is placed in service by the required date (if not, the credits are recaptured back to December 31, 1985).

Beginning January 1, 1986, any property which qualifies for the ITC is subject to a basis adjustment for the full amount of the ITC, rather than the adjustment for half of the credit under prior law. Also beginning January 1, 1986, the ITC can offset at most $25,000 plus 75 percent of the amount of tax liability in excess of $25,000 (the percentage was 85 under prior law). Beginning July 1, 1987 (the date of the tax rate reduction), the amount of the ITC and any remaining ITC carryforwards are reduced by 35 percent.

The Tax Reform Act requires continued normalization of the investment tax credit, both credits previously received and those received during the transition period. This requirement seems consistent with the policy objectives of the existing normalization requirement and with the economic effects of the ITC on a utility asset.

Repeal of the investment credit with regard to new investments does not alter the policy objectives associated with the credit during its existence nor their relationship to the normalization requirement. The latter was enacted and has been amended over the years principally to avoid the tax revenue losses associated with flow through treatment and to ensure that the ITC would have the intended effect in the public utility industry. As with accelerated depreciation, under flow through treatment of the investment credit, the tax revenue losses in a regulated industry are larger early in the lives of assets and smaller later than under normalization ratemaking treatment. Similarly, if prior ITCs were allowed to be flowed through after repeal of the credit, tax collections from utilities would be smaller in the first several years after repeal (and higher in later years) than if normalization of the prior credits continued to be required.

Also similar to accelerated depreciation, Congress intended the ITC to reduce the after-tax acquisition cost of capital assets and intended the tax saving resulting from the ITC to be available to finance capital investments. Flow through treatment of the prior ITCs would fail to meet the second of these objectives because the portion of prior investments financed by deferred investment tax credits would have to be refinanced by private capital.

Since the effects of the ITC on an investment all occur at the outset, repealing the ITC for subsequent investments does not change the economic effects of the credit on the original qualifying investment. The credit has an effect on an investment similar to a price reduction in the investment asset. A price increase which occurs after an investment asset has been purchased does not change the effect of the price of the original investment. Hence, repeal of the investment credit for new investments does not change the appropriateness of normalization treatment for credits received prior to repeal.

The investment credit does create a permanent rather than a timing difference between actual taxes and book taxes, but the tax reduction resulting from the credit is a capital subsidy intended to have effects similar to a price reduction on investment assets. Achieving these effects requires normalization treatment, and this fact is not changed by repeal of the credit for future investment.

Finally, normalization of the investment credit emulates the effects of the ITC in the unregulated industries (except to the extent that the ITC normalization rules in the tax code are inconsistent with “economic normalization”). That is, in general terms, normalization causes the ITC to have effects in regulated industries similar to a price reduction (or a purchase subsidy) on capital assets.

Revision of Accelerated Depreciation

The Tax Reform Act revises the Accelerated Cost Recovery System (ACRS) enacted in 1981. For most types of property the act lengthens the depreciation period but accelerates the depreciation method. For most types of public utility property, however, the depreciation period is lengthened, but the depreciation method remains unchanged.

Under the new system, most business equipment, previously in the five-year class will now be in a seven-year class. Telephone computer-based central office switching equipment and nuclear fuel assemblies have been assigned to a five-year class. Assets in
classes up to the ten-year class receive double declining balance depreciation, an acceleration from the 150 percent declining balance method available under prior law. Public utility property previously in the ten-year class, which includes nuclear generating plant and most gas pipeline assets, will now be in a fifteen-year class (telephone distribution plant has also been put in this class). Public utility property formerly in the fifteen-year class, which includes nonnuclear electric generating plants, electric transmission and distribution facilities, and gas plant and distribution facilities, will now be in a twenty-year class. These classes continue to receive 150 percent declining balance depreciation. Nonresidential real property must be depreciated using the straight-line method over 31.5 years.

The new depreciation system is generally applicable to property placed in service after 1986, but taxpayers may elect to apply the system to property placed in service after July 31, 1986. This election is beneficial for some short-lived property that qualifies for double declining balance depreciation under the new system. Just as for the repeal of the investment credit, numerous transition rules apply to the accelerated depreciation revisions. The general rule permits use of the previous depreciation system for property for which a binding contract was in effect on March 1, 1986, with the same requirements as for the ITC regarding the dates the property must be placed in service.

The act continues the present law’s normalization requirement for accelerated depreciation, and the same rationale applies.

Capitalization of Construction Period Expenses and Inventory Costs

The Tax Reform Act contains a set of “uniform capitalization rules” which replace previous capitalization requirements and apply to a wide range of activities involving manufacturing or constructing real or personal property for resale or the taxpayer’s business use. The rules extend the list of activities for which costs must be capitalized, broaden the types of costs which must be capitalized, and change the capitalization rules for some types of costs.

These rules will require comprehensive capitalization of the costs of constructing utility plants and distribution systems. The new requirements apply to costs incurred after December 31, 1986, except that projects for which substantial construction occurred before March 1, 1986, continue to be covered by the prior rules. Not only will direct costs have to be capitalized under the new system, but also taxes, interest, pensions and other employee benefits, and an appropriate portion of general and administrative costs. Under prior law the required treatment of indirect costs was uncertain. The previous rules which allowed amortization of construction period interest and taxes on real property over a ten-year period are no longer applicable. Interest and taxes on both real property and long-lived personal property are to be capitalized like all other expenses. Furthermore, the amount of interest allocated to a construction project is the amount of interest expense that could have been avoided if the construction expenditures had been used to repay debt. This rule, in effect, assumes that 100 percent of the construction is debt financed (unless the total debt of the company is less than the construction cost).

For projects covered by this provision, the new rules will result in smaller tax deferrals during the construction period. The capitalization rules do not institute income measurement procedures that match AFUDC treatment (which is more consistent with the economic character of the investment/construction activity), but they move in that direction. To the extent that the avoided cost method of determining interest attributable to the project results in capitalizing a larger amount of interest than is included in AFUDC, the capitalization process indirectly taxes a portion of the equity component of AFUDC.

The new uniform capitalization rules also apply to inventory costs, which affect gas and water utilities. As is the case for self-constructed assets, the rules require comprehensive capitalization of the costs of acquiring inventory, including indirect costs. The conference committee report states it is not intended that the rules require any portion of overhead or other indirect costs to be allocated to “cushion gas” and that the Treasury Department may also issue regulations exempting some portion of “emergency reserve gas.” The effect of the inventory capitalization rules will be to increase the value of inventories on hand at the end of the tax year. The resulting adjustment in taxable income may be spread over a period of up to four years.
Corporate Alternative Minimum Tax

Beginning in 1987, the Tax Reform Act replaces the previous add-on minimum tax with a new alternative minimum tax (AMT) on corporations that is much broader than its predecessor. The tax is designed to assure that most profitable corporations will pay at least some federal income tax. The AMT is essentially a separate income tax with the actual amount of tax liability determined by the relationship between the AMT and the regular income tax. For public utilities and most other corporations the AMT will operate basically to accelerate tax payments for those companies that would otherwise have a low regular tax liability due to tax deferral items. It is an understatement to say that the way in which this objective is achieved is extremely complex.

Alternative minimum taxable income (AMTI) equals regular taxable income (before deduction of NOL carryovers) plus certain preferences and adjustments. Two of these items—depreciation and untaxed reported book income—are particularly important for utilities. The new AMT depreciation system applies to assets placed in service after 1986 which are not covered by the regular tax accelerated depreciation transition rules. The AMT contains a complete depreciation system separate from the regular tax rather than just an add-on preference for accelerated depreciation as under the prior minimum tax. Thus, assets will have not only annual depreciation amounts under the AMT which differ from the regular tax but also a different basis. Under this system, a sale or other disposition of an asset will result in gain or loss for both the regular tax and the AMT (in general, the amounts under the two taxes will differ).

For most real property, AMT depreciation is based on a forty-year life and the straight-line method. Under the previous minimum tax, the tax preference for accelerated depreciation on real property was the excess of accelerated over straight-line depreciation but using the same depreciation life. For personal property, AMT depreciation is based on the asset depreciation range (ADR) midpoint life and the 150 percent declining balance method. Under the previous minimum tax, accelerated depreciation on personal property was not a tax preference except with regard to leased property in the hands of a personal holding company.

The second preference of particular importance to utilities is untaxed reported book income. There was no comparable provision under the prior minimum tax. This tax preference, while controversial, is the central feature of the new minimum tax, for it assures that profitable corporations will pay at least some income tax. To compute this preference, book income must be adjusted, if necessary, to reflect the same set of corporations included in the taxpayer’s consolidated tax return. One-half the amount by which adjusted pretax book income exceeds AMTI (prior to reduction by net operating losses) is the preference. In 1990 the book income preference will be replaced by one based on “adjusted current earnings,” the calculation of which is based on the rules for computing earnings and profits.

Net operating losses (NOLs) adjusted to be consistent with the AMT (preferences must be added back in for years after 1986) may be carried over and used to offset up to 90 percent of AMTI in other years. There is a $40,000 exemption against the AMT which is phased out at a rate of 25 cents per dollar for AMTI between $150,000 and $310,000. The tax rate of the alternative minimum tax is 20 percent. Investment credit carryovers and transitional credits may be used to offset up to 25 percent of the AMT; if the AMT is less than the regular tax, investment credits may not be used to reduce tax liability to less than 75 percent of the AMT. Hence, NOL and investment credit carryovers may be used to offset the AMT but not fully. In general, if a company has book net income, it will pay some federal income tax under the new structure.

The amount of AMT liability in excess of the regular tax becomes a credit against future regular tax liability, subject to the limit that the credit cannot reduce tax below the AMT liability in any year. In calculating the credit, four AMT preference items which are regarded as exclusion preferences rather than timing preferences are omitted, and the effect of the investment credit is ignored.

The effect of the AMT will be to prevent tax deferral items from reducing tax liability below specified levels related to book income. To the extent that the AMT causes tax liability to be higher than regular tax, the excess becomes a credit usable in a future year when the regular tax again exceeds AMT. Thus, the AMT essentially operates to negate a sufficient amount of tax deferrals to assure a minimum tax payment each year (the negated deferrals may be subsequently reinstated, however, if regular tax
liability in a subsequent year is high enough).

Understanding the operation and effect of the new alternative minimum tax will be important to regulators. The earlier minimum tax had relatively little effect on most utilities because they had little of the designated tax preferences. In contrast, the new minimum tax, while likely have a substantial effect on utilities. The book income tax preference will be significant for utilities because of two factors: accelerated depreciation and AFUDC.

As discussed above, the new depreciation rules will reduce the amount of deferred taxes of utilities attributable to accelerated depreciation. Also, the requirements for capitalizing construction period expenses will indirectly move tax accounting closer to AFUDC treatment. These new rules, however, apply only to new assets and new construction projects. The book income preference of the minimum tax will have the effect (where it applies) of reducing the tax deferrals attributable to accelerated depreciation and partially taxing AFUDC with regard to existing assets and projects and those covered by the transition rules. Thus, the "grandfathering" of the tax treatment of existing assets and projects by the transition rules in the tax bill is not complete. This relationship also implies that, to the extent companies pay the minimum tax due to the book income preference, the applicability of the tax is likely to diminish gradually in the future as an increasing proportion of assets come under the new depreciation and capitalization rules. In the longer run, the minimum tax will probably affect most utilities only in the initial phase of growth spurts, when regular tax accelerated depreciation will exceed minimum tax accelerated depreciation by larger than normal amounts.

Regulatory commissions will have to consider the nature of the factors creating alternative minimum tax liability for the utilities under their jurisdiction in determining ratemaking treatment. For the most part, the tax will not simply represent an added tax liability as did the earlier minimum tax. Rather, as stressed above, the new minimum tax operates largely to negate a certain amount of tax deferrals, with possible later reinstatement. Hence, the appropriate ratemaking treatment will require adjustment to deferred tax accounting procedures.

It should also be noted that Congress passed an additional tax based on alternative minimum taxable income. The Super-

fund Amendments and Reauthorization Act of 1986 imposes an environmental tax on all corporations, effective for 1987 through 1991, at the rate of 0.12 percent on AMTI (before deduction of net operating losses) in excess of an exemption of $2 million.

Accrual Accounting for Utilities

The Tax Reform Act requires utilities using the accrual method of accounting to recognize income from providing utility services in the year in which the service is provided. Prior to the act there was dispute over the application of accrual accounting to utilities (which may continue regarding years prior to 1987). The IRS had announced in April 1986 that it would permit utilities to recognize income in a taxable year based on when a customer's utility meter is read only if the same method is used for book purposes. Some court cases, however, had allowed taxable income to be recognized based on meter readings regardless of the method used to determine book income, and in some cases had allowed taxable income to be determined based on when customers are billed rather than on when meters are read.

The act requires recognition of the income in the year the service is provided beginning in 1987. This will require estimates of the service provided from the last meter reading to the end of the year, which may be based on a pro rata allocation of service between the last meter reading of the taxable year and the first reading of the following year. The costs of providing the utility services may also be deducted during the taxable year if economic performance has occurred. The net adjustment required by this provision may be taken into taxable income ratably over a four-year period.

Contributions in Aid of Construction

The Tax Reform Act terminates the present treatment of contributions in aid of construction in electric, gas, water, and sewage utilities. Currently, these are not included in taxable income, and the assets purchased with the contributions have no basis, do not qualify for the investment credit, and may not be included in the utility's rate base. The act repeals this treatment for years after 1986. Thus, contributions in aid of construction will be taxable.
income to the utility, and the assets purchased with the contributions will be depreciable.

Contributions in aid of construction are, in essence, a prepayment for future utility services. The current treatment, in effect, exempts from tax the income from services provided by the assets financed by the contributions. The new treatment will tax that income the same as any other utility income. This will result in an increase in the amount utilities will charge as contributions in aid of construction. After implementation of the act, the contributions not only will have to cover the (after-tax) cost of providing the service, but also (as is the case with payments for other utility services) will be grossed-up to cover the tax on the income derived from providing the service.

**Overall Consequences for Utilities**

Among the changes discussed above, all but the tax rate reduction will have the effect of increasing taxes for public utilities. Nonetheless, it would seem reasonable to expect that federal income taxes paid by most utilities will decline at least during the next few years as a result of the Tax Reform Act of 1986. The corporate tax rate decrease, which takes effect in mid-1987, is substantial (more than a 25 percent cut). While the repeal of the ITC, the depreciation revisions, and the capitalization requirements will have substantial future effects on utilities, the current effects are largely mitigated by transition rules which "grandfather" current assets and projects. The full effect of the tax revisions, therefore, will not be felt until the next cycle of construction projects, which, at least in the case of electric utilities, is far in the future. Even telephone utilities, with their shorter asset lives, will not experience the full effect of the tax revisions for several years.

The changes in the accrual accounting rules and the treatment of contributions in aid of construction will have immediate effects, but these are small items compared to the tax rate reduction. The provision which has the potential to raise taxes in the short run, at least for some utilities, is the new alternative minimum tax. The AMT is very complex, and its effect depends on a host of factors specific to a company. In general, however, ignoring the effects of NOL carryovers and other special considerations, the tax will assure that corporations have an effective tax rate of at least 7.5 percent based on book income. Based on aggregate data, industrywide effective tax rates are higher than this level: 11.3 percent in the electric utility industry, 20.9 percent in the telephone industry, and 33.4 percent in the gas utility industry.

Within each industry, of course, there is variation around these rates. Utility companies with low tax payments because of current or recent construction programs may face higher taxes immediately under the minimum tax. It is more likely to affect electric utilities, which historically have had low effective tax rates, than telephone or gas utilities. To the extent that higher taxes are attributable to the minimum tax, however, they result in credits which may be used to offset taxes in the future once regular tax liability reaches higher levels.

Utility rates charged to customers are also likely to decrease as a result of the Tax Reform Act for two reasons. First, the tax rate decrease directly reduces the tax component of the cost of service in ratemaking and reduces utility rates. The speed with which this occurs depends on how quickly regulatory commissions approve rate reductions based on the tax decrease. In some states, commissions have called for rate reduction submissions by their utilities. In others, utilities have taken the initiative to request rate reductions to reflect the tax decrease. In the latter cases, one suspects that the utilities may prefer to initiate the rate reduction rather than to invite close regulatory scrutiny of their finances at a time of generally decreasing financing costs.

The second reason utility rates will be reduced is the continued normalization of past tax deferrals and deferred tax credits. Formerly, the effect of past deferrals in reducing utility rates has usually been swamped by the effect of new deferrals in increasing rates. In the future, as the ITC and accelerated depreciation disappear or diminish as sources of new deferrals, the amortization of prior deferrals will be a force that reduces utility rates. Previously, the normalization process has been criticized for charging customers for "phantom taxes"; in the future, utility customers will receive rate reductions from "phantom tax benefits" provided by tax incentives long since limited or repealed.

The cost of capital to utility companies will be affected in several ways by changes in the Tax Reform Act, some of them indirect. For example, because of the reduced individual tax rates and the repeal of the exclusion of 60 percent of long-term capital gains, investors are more attracted to income producing financial
assets, such as bonds and high dividend stocks, and less attracted to growth stocks. This reorientation should benefit utilities who are heavy borrowers and whose stocks have traditionally paid high dividends. In fact, utility stocks were among the best performers in 1985-1986 while the tax bill was under development in Congress. Higher stock prices reduce the cost of equity capital to the utilities.

The Tax Reform Act is widely expected to result in a decrease in interest rates in the economy not only for the reason just mentioned but also because it should reduce the demand for credit. Borrowing by individuals is expected to decrease because the deductibility of interest on consumer borrowing is being phased out. Borrowing by businesses is expected to decrease because the tax bill increases the taxation of profits from investment. A decrease in interest rates, of course, also reduces the cost of capital to utilities. Like the increase in stock prices, some or nearly all of this effect may have already occurred as it became increasingly apparent that the tax bill would be enacted.

The reduction of tax deferrals, however, will reduce cash flow and increase capital costs of utilities in the longer term. The ITC and accelerated depreciation, combined with normalization ratemaking treatment, have been substantial sources of cash flow for utilities. These cash flow sources will diminish in the future and perhaps even turn tax deferrals at negative as new tax deferrals are greatly reduced and large prior tax deferrals are amortized. The current required method of normalizing the investment credit increases the equity earnings of utilities above the rate of return stated in the ratemaking process because the deferred ITCs are not allowed to be excluded from the rate base. As deferred ITCs are amortized, therefore, this source of "extra earnings" will disappear, resulting in a downward adjustment in the price of utility stock. The reduction of accumulated deferred taxes will also increase utility capital costs as zero-cost capital (tax deferrals) is replaced by debt and equity.

The Tax Reform Act would also be expected to affect the investment decisions made by utilities for reasons in addition to the effects on utility rates and capital costs described above. There has been criticism in the past that the tax code biased utilities toward capital-intensive technologies because of the large tax benefits associated with capital investment. This criticism was most often directed at the huge investment of electric utilities in nuclear capacity as opposed to other less capital-intensive, but more fuel-intensive, technologies. The Tax Reform Act, by reducing the investment-related tax benefits, decreases the relative attractiveness of capital-intensive technologies.

In summary, the Tax Reform Act of 1986 will have substantial effects on public utilities. The previous corporate tax system was characterized by a high tax rate and provisions which granted substantial investment-related tax reductions. Under that system, the utilities accumulated substantial tax deferrals and during periods of high construction activity paid little or no federal income tax. At the same time, the charge to utility customers for corporate tax payments was based on the high statutory tax rate, which led to complaints from consumer groups. The new system is characterized by a lower tax rate and a tax base which comes much closer to measuring economic income. Once this new system is fully phased in, utilities will have much smaller tax deferrals and will pay taxes more closely matching the charges for taxes included in utility rates, which will be lower because of the reduced statutory tax rate. This also means that the earnings and especially the cash flow of utilities will be even more heavily dependent on the decisions of regulatory commissions.

Notes
1. As under current law, lower tax rates apply to corporations with low taxable income, and a surtax over a higher income range produces a flat rate tax for larger corporations. Under the new law, a flat 34 percent tax rate will, in effect, apply to all corporations with taxable income above $335,000.
2. The penalty for noncompliance is the same as the penalty associated with the accelerated depreciation normalization requirement: The utility's assets would no longer qualify for accelerated tax depreciation.
5. See the discussion in Donald W. Kiefer, Accelerated Depreciation and the Investment Tax Credit in the Public Utility Industry: A Background Analy...
6. Flow through in this context will be used to refer to passing the benefit from the tax rate reduction through to customers in reduced utility rates over a period shorter than the remaining lives of the utility's assets (say, a period of three to five years) rather than necessarily reducing rates in the year of the tax reduction to reflect the full benefit.


8. Under normalization treatment utilities receive a cash flow benefit but do not earn higher profits.

9. For self-constructed property, the rule requires that by December 31, 1985, construction must have begun, and at least 5 percent of the cost of the property or $1 million (whichever is less) must have been incurred or committed.

10. There is an additional limitation that the ITC cannot reduce tax liability to less than 75 percent of the amount of the alternative minimum tax, see discussion below.

11. The penalty for noncompliance is recapture of investment credits or reduction of credit carryforwards. The amount of the recapture or reduction would be the greater of (1) credits for open taxable years of the utility or (2) unamortized credits.

12. See the discussion in the source cited in note 5.


14. The rule regarding self-constructed property is the same for accelerated depreciation as for the ITC, except for the March 1, 1986, date.

15. See the source cited in note 5 for a review of the rationale for the normalization requirement for accelerated depreciation.

16. The interest capitalization rules are separate from the others. Property for which construction period interest must be capitalized includes: (1) real property, (2) property with a class life of twenty years or more, (3) property with a construction period of more than two years, and (4) property with a construction period of more than one year and costing more than $1 million.

17. The conference committee report states that the avoided cost method of determining interest allocable to a project is to be used regardless of whether it is appropriate or authorized for other purposes. Specifically, "a regulated utility company must apply the avoided cost method of deter-
Flowbacks and Deferrals under the 1986 Tax Reform Act: Normalization or Confiscation?

Michael Foley

About five years ago the National Association of Regulatory Commissioners (NARUC) was invited to testify on a bill pending before the U.S. House Committee on Ways and Means which would have cleared up a longstanding technical dispute between the IRS and a number of utilities regulated by the California Public Utilities Commission.

In the course of presenting the NARUC position on the issue and fending off questions from Member of Congress, it was suggested that perhaps what we ought to do is abolish federal income taxation on all public utility companies and simply levy an excise tax on utility services. That way we would not have to fight over normalization, ITCs, contributions in aid of construction, unbilled revenues, interest synchronization, and so forth.

Congressman Pete Stark of California, who was on the panel at the time, responded that such a legislative effort would surely fail because, ironically, it would be the utility lobby that would fight to preserve the federal tax system as it then existed. Stark added that he once floated such a bill, and it died a quick death at the hands of the Washington ratepayer funded utility lobby.

One of the first questions I want to examine here is why utility companies, particularly the larger gas, electric, and telephone companies, love the federal tax code. Why would they fight to preserve it over the alternative of paying NO federal income taxes and merely collecting an excise tax on utility services provided?

In order to appreciate the "beauty" of the federal tax system from the utility's perspective it is helpful to draw an analogy between the utility's procurement of other supplies and services and the procurement of government services, which is presumably what one receives when one pays his taxes.

When a utility pays $100 for paper clips, or $1,000 for the president's travel expenses, or a million dollars for tree trimming services, the regulatory implications and considerations are really quite simple. Certainly, one can question the level of the expenditure—perhaps the tree trimming services could have been performed for $950,000. Ultimately, however, the regulator must merely determine whether the cost was reasonable and necessary for the proper operation of the corporation and then order that the cost be passed on to ratepayers.

However, with the purchase of government services and the corresponding "cost" of paying federal income taxes, life is not so simple. The Internal Revenue Service, via whatever complex formulas Congress has written into law applicable for that year, determines the price it will apply to the services the government has provided the utility that year. In year one, for example, the government decides that the price is $100. The utility then dutifully collects $100 from its ratepayers and proceeds to pay the federal Treasury. Except that before the payment is actually rendered, the utility determines upon a closer reading of the tax code that it is merely required to remit $50. The balance is held as a future tax obligation or more properly in an account titled "Accumulated Deferred Income Taxes."

The $50 in deferred taxes is held by the utility with the understanding that at some future date the payment will be required by the federal government. Ratepayers have, in effect, created an interest-free loan to the utility. Over time this repeated process creates a rather large loan. In fact using year-end 1984 figures the nation's combined electric, gas, telephone, and water indus-
tries held more than $60 billion in funds collected from ratepayers through the years which have not yet been paid to the Treasury. Indeed, the figure increases by several billion each year. This whole process takes place in large measure because of accounting timing differences created by the use of accelerated depreciation for tax purposes and straight-line depreciation for regulatory purposes. The use of different depreciation schedules for tax and book purposes creates a deferral of the current federal tax obligation, and the utilities are therefore allowed to over-collect the tax component of their revenue requirement year after year after year.

Conventional accounting theory provides that timing differences eventually reverse and that all deferred taxes are paid however, theory and practice differ substantially, and the available data shows that utilities for the most part have been able to more than offset the reversal of deferred taxes with new deferred taxes created via the purchase of new assets. This is documented in Table 1, 2, and 3, which show the substantial—indeed, radical—increases in the deferred tax balances of the nation’s major utility companies. Table 1, for example, shows that deferred tax balances in the electric industry have routinely increased by 20 percent or more per year. In the natural gas pipeline industry (Table 2) the story is much the same, although the increases are not quite as consistent.

The question as to whether deferred taxes ever really get paid to the Treasury has been a rather contentious issue for many years. Critics of normalization accounting argue that deferred tax balances represent phantom taxes imposed on utility ratepayers which will never be paid to the government. Indeed, about twenty years ago Price Waterhouse conducted a study on the generic question of tax accounting which seems to bolster these claims. Examining the deferred tax balances of 100 major U.S. corporations from 1954-1965, the study concluded: "With respect to accelerated depreciation and installment sales the aggregate paybacks have been minute in comparison with the charges. Moreover, there are no indications from the data that the payback experience of the future will be any different from that of the past... These so-called 'deferred income taxes' arising from recurring items of this nature are perhaps best described as 'hypothetical income taxes.'"

Should ratepayers care that they have, for three decades or so, paid $60 billion or more in revenues to the utilities in the name...
<table>
<thead>
<tr>
<th>Year</th>
<th>Accumulated Deferral</th>
<th>Increase</th>
<th>Increase Over Previous</th>
<th>Income Over Previous</th>
</tr>
</thead>
<tbody>
<tr>
<td>1970</td>
<td>$394,748</td>
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<td></td>
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</tr>
<tr>
<td>1971</td>
<td>$445,035</td>
<td>$50,287</td>
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<td></td>
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<tr>
<td>1972</td>
<td>$544,294</td>
<td>$99,259</td>
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<td></td>
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<tr>
<td>1973</td>
<td>$745,634</td>
<td>$201,340</td>
<td>37%</td>
<td></td>
</tr>
<tr>
<td>1974</td>
<td>$938,521</td>
<td>$192,887</td>
<td>26%</td>
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<tr>
<td>1975</td>
<td>$1,121,205</td>
<td>$182,684</td>
<td>19%</td>
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</tr>
<tr>
<td>1976</td>
<td>$1,489,223</td>
<td>$368,018</td>
<td>33%</td>
<td></td>
</tr>
<tr>
<td>1977</td>
<td>$1,620,655</td>
<td>$131,432</td>
<td>9%</td>
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<td>1978</td>
<td>$1,757,483</td>
<td>$136,796</td>
<td>8%</td>
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<tr>
<td>1979</td>
<td>$2,261,035</td>
<td>$503,584</td>
<td>29%</td>
<td></td>
</tr>
<tr>
<td>1980</td>
<td>$2,331,119</td>
<td>$70,084</td>
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<tr>
<td>1981</td>
<td>$2,390,303</td>
<td>$578,184</td>
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<tr>
<td>1982</td>
<td>$3,777,180</td>
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<td>1983</td>
<td>$4,294,352</td>
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<tr>
<td>1984</td>
<td>$4,790,337</td>
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<tr>
<td>1985</td>
<td>$5,121,283</td>
<td>$330,946</td>
<td>7%</td>
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</table>


<table>
<thead>
<tr>
<th>Year</th>
<th>Accumulated Deferred Income Taxes</th>
<th>Increase Over Previous</th>
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</thead>
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<td>1972</td>
<td>$1,085,568</td>
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<td>1973</td>
<td>$1,202,215</td>
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<td>1974</td>
<td>$1,398,862</td>
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<td>1975</td>
<td>$1,595,509</td>
<td>$196,647</td>
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<tr>
<td>1976</td>
<td>$1,792,156</td>
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<td>1977</td>
<td>$1,988,803</td>
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<td>1978</td>
<td>$2,185,450</td>
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<tr>
<td>1979</td>
<td>$2,382,097</td>
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<tr>
<td>1980</td>
<td>$2,578,744</td>
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<tr>
<td>1981</td>
<td>$2,775,391</td>
<td>$196,647</td>
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<tr>
<td>1982</td>
<td>$3,072,038</td>
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<tr>
<td>1983</td>
<td>$3,368,685</td>
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<tr>
<td>1984</td>
<td>$3,665,332</td>
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<tr>
<td>1985</td>
<td>$3,961,979</td>
<td>$196,647</td>
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</table>

Table 2.

<table>
<thead>
<tr>
<th>Name of Company</th>
<th>Accumulated Deferred Income Tax Increase</th>
<th>DEFERRED TAX BALANCE 1972-1985</th>
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<tr>
<td>ALABAMA PWR. CO.</td>
<td>$27,153,219</td>
<td>$778,356,070</td>
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<tr>
<td>APPALACHIAN PWR. CO</td>
<td>$37,063,400</td>
<td>$1,085,568,944</td>
</tr>
<tr>
<td>ARIZONA PWR. CO.</td>
<td>$2,627,457</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>KENTUCKY PWR. CO.</td>
<td>$9,637,220</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>LOUISIANA PWR. CO.</td>
<td>$12,029,150</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>MISSISSIPPI PWR. CO</td>
<td>$2,324,334</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>MICHIGAN PWR. CO.</td>
<td>$10,500,000</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>OHIO PWR. CO.</td>
<td>$13,457,500</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>SOUTH CAROLINA PWR. CO</td>
<td>$7,384,000</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>WASHINGTON PWR. CO.</td>
<td>$12,029,150</td>
<td>$778,356,070</td>
</tr>
<tr>
<td>WISCONSIN PWR. CO.</td>
<td>$2,324,334</td>
<td>$778,356,070</td>
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</tbody>
</table>

Table 3.
### Normalization or Confusion?

<table>
<thead>
<tr>
<th>Name of Company</th>
<th>Accumulated Deferred</th>
<th>Accumulated Defeered</th>
<th>Deferred Tax</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Income Taxes</td>
<td>Income Taxes</td>
<td></td>
</tr>
<tr>
<td>ELECTRICITY PUR CHC CO</td>
<td>$3,774,105</td>
<td>$20,018,307</td>
<td>$30,002,956</td>
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<tr>
<td>MID-AMERICA PUR CHC CO</td>
<td>$8,114,720</td>
<td>$20,115,399</td>
<td>$13,767,189</td>
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<tr>
<td>MONTANA SOUTHERN UTILITIES CO</td>
<td>$51,039,087</td>
<td>$85,193,725</td>
<td>$147,458,482</td>
</tr>
<tr>
<td>MONTANA PUR CO THE</td>
<td>$37,370,630</td>
<td>$89,274,712</td>
<td>$182,053,482</td>
</tr>
<tr>
<td>NEVADA PUR CO</td>
<td>$51,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>NEW YORK STATE ELEC &amp; GAS COR</td>
<td>$5,092,090</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>RHODE ISLAND PUR CHC CO</td>
<td>$10,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>SOUTHERN MA PUR SERV CO</td>
<td>$10,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>SOUTHERN STATES PUR CO</td>
<td>$10,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>WHITE ELECTRIC CO</td>
<td>$10,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
<tr>
<td>WISCONSIN PUR CO</td>
<td>$10,402,034</td>
<td>$37,370,630</td>
<td>$58,195,417</td>
</tr>
</tbody>
</table>

### Source:

U.S. Energy Information Administration
U.S. Department of Energy

and data provided annually by the electric utility companies in the FERC Form 1 Table 3 (cont.)

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Michael Foley

of "taxes" which the companies in turn have not yet paid to the Treasury due to an accounting technique known as normalization? Several reasons often are given as to why ratepayers should care.

1. The ratemaking process is distorted, and the inherent logic of paying a dollar in utility rates to cover a dollar in utility expenses is compromised with the resultant effect that consumers lose confidence in the integrity of the rate-setting process. (2) The argument is made that in the utility industry the incentives created by accelerated depreciation encourage companies (particularly electric utilities) to overbuild or select capital-intensive options for expansion rather than so-called soft path or least-cost options. (3) A more generic argument, and one which I think has a certain appeal, maintains that utilities after all are by definition monopolies and therefore do not need any incentives cleared through the federal tax code to invest in new assets. Presumably, they will procure only those assets needed to meet basic services in their respective jurisdictions, why should the tax code provide an extra kick to invest for those companies which by law are required to have sufficient plant and capacity to serve their customers. (4) Federally mandated normalization is an unnecessary intrusion into the rate-making process. State regulators are entrusted to establish fair and reasonable rates balanced with the financial needs of the utilities in their jurisdictions, and therefore Congress has no business setting ratemaking policies.

The arguments in favor of normalization are extensive and will not be repeated here, with one exception. The one compelling argument in favor of normalization, and one often overlooked by advocates of flow-through accounting, is that normalization does provide a ratepayer benefit over the life of the asset in that the capital created via deferral of current taxes is in effect interest-free capital and the firm is thus relieved of the financing costs associated with that sum of money.

For that reason I generally support normalization accounting and would probably recommend its adoption were I in a position to do so, although I think it is entirely inappropriate for normalization to be written into the tax code and therefore imposed on utility regulators. The state commissions ought to have a free hand to adopt flow through accounting or any one of dozens of other techniques which fall somewhere between normalization and flow through. It is only when balanced with this ratemaking flexibility
that normalization is acceptable.

The key point is that accounting for income taxes is a critical component of the rate-setting process and is therefore best left to those lawfully charged with the task. If Congress had limited its intrusion into the process to this one instance, the nation’s utility consumers would not have been significantly harmed, for as I pointed out normalization of accelerated depreciation tax benefits does provide a ratepayer benefit in terms of a lower cost of capital. However, Congressional intrusion has not stopped there.

The essential problem is that the Washington utility lobby has sold Congress on “normalization” whenever they need further to preempt the ratemaking process; they simply call it “normalization,” run to their friends on the congressional tax-writing committees, and sell all manner of inappropriate tax schemes. Clearly, I do not accept the notion that Congress should set ratemaking policies. Needless to say, the utility lobby has convinced many that Congress does have an interest in these matters. For those who accept that view, does it not logically follow that Congress ought at least to do it properly. I will cite several instances in which I think Congress has “botched up” its new role as utility ratesetter.

**Excess Deferred Taxes**

The first and most recent example relates to Section 203(e) of the 1986 Tax Reform Act, which defines *normalization* to include specific mechanisms for accounting for the effects of the cut in the corporate income tax rate from 46 percent to 34 percent and its resultant effect on deferred tax balances, which were “grouse up” at the 46 percent rate.

Table 4, 5, and 6 give data on the total accumulated deferred income taxes for the nation’s major electric, gas pipeline, and telephone companies. As I mentioned earlier, accounting theory provides that deferred tax balances created by timing differences, such as the use of different asset lives for tax and book purposes, will eventually reverse and “zero-out.” As shown in the tables, deferred tax balances are enormous and were collected from ratepayers under the assumption that they would eventually be paid at the same rate collected. In other words, deferred tax balances grossed up at the 46 percent rate will—in theory—eventually reverse and be paid future date at the same rate.
### Normalization or Confusion? 

<table>
<thead>
<tr>
<th>COMPANY</th>
<th>ACCUMULATED</th>
<th>DEFERRED</th>
<th>EXCESS</th>
<th>DEP. TAXES</th>
<th>UNDER 50</th>
<th>TAXES</th>
<th>RATEPAYERS</th>
</tr>
</thead>
<tbody>
<tr>
<td>ATT Communications</td>
<td>$1,465,988,715</td>
<td>$716,318,374</td>
<td>$186,805,563</td>
<td>$295,015,621</td>
<td>$66,274,460</td>
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<td>Illinois Bell Telephone Co.</td>
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<td>$520,205,607</td>
<td>$1,520,123,245</td>
<td>$121,303,123</td>
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<td>$1,341,205,789</td>
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<td>$226,451,105</td>
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<tr>
<td>Ohio Bell Telephone Co.</td>
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<td>Wisconsin Bell</td>
<td>$250,180,205</td>
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<tr>
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<tr>
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<tr>
<td>C F P of Maryland</td>
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<td>$101,927,736</td>
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<td>General Telephone Co. of Indiana</td>
<td>$3,246,417</td>
<td>$2,034,823</td>
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<td>$459,581</td>
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</table>

**TOTAL (1984)**

$22,922,227,461 $5,797,713,134

Source: U.S. Federal Communications Commission

Table 6.

Any accountant worth his salt can readily go through the mechanics of this process and show how the reversal works and how, over the full book life of the asset, the taxes are eventually paid to the Treasury. However, the process comes "unglued" when the corporate tax rate is cut at some point after the dollars have been collected, but before they are paid to the Treasury, which is precisely what has happened: The corporate tax rate has been cut to 34 percent, a reduction of 12 percent. By multiplying the accumulated deferred tax balance by 12 over 48, one can come up with a rough approximation of the amount of taxes which have in effect been forgiven and thus no longer represent an obligation of the utility to the federal Treasury.

In the case of the electric industry the amount forgiven is roughly equal to $8 billion dollars using 1985 data. In the case of the telephone industry the amount is approximately $6 billion. Finally, in the gas pipeline industry the figure is approximately $1.3 billion.

In sum, of the roughly $58 billion in funds which electric, gas, and telephone utilities are currently carrying on their books as a tax liability owed to the federal government, the 1986 Tax Act forgives more than $15 billion. Ratepayers have thus overpaid the federal tax component of the cost of service by $15 billion and are accordingly due a refund in that amount.

It is interesting to note that despite wide differences of views over the timing of the repayment of the excess deferred taxes, the utility lobby is at least willing to acknowledge that these taxes do, indeed, represent funds owed to ratepayers. Unfortunately, in the name of "normalization," it has convinced Congress to include language—specifically that found in Sec. 203(a) of the Tax Reform Act—which effectively prevents utility regulators from giving customers their money back on a timely basis.

In simplest terms, the effect will be to flow back the funds due ratepayers over the average remaining book lives of the utility's assets. In the case of the electric utility industry refunds to customers will thus be flowed back over as much as 25-30 years. On a present value basis, assuming an inflation rate of 5 percent per year, customers will be repaid at the rate of roughly 50 cents on the dollar, provided they live long enough to receive the full refund.

What are the arguments to defend this substantial intrusion into a rather crucial ratemaking decision? First, the utilities claim
that ratepayers are not suffering a loss because deferred taxes, after all, are always excluded from ratebase. This strikes me as a rather shallow argument. Ratepayers have undoubtedly overpaid utility taxes by many billions of dollars and are thus due a refund. The fact that the overpayment is not earning a rate of return is hardly a valid reason for delaying repayment for 25 years or more. If the utility argument were valid, then perhaps what we ought to do is require ratepayers to overpay all utility expenses by many tens of billions and then delay the refunds—an absurd proposition indeed. Second, utilities argue that, if given the opportunity, the political pressures being what they are on the ratemaking process would force utility regulators to refund the excess taxes under an excessively rapid time schedule which would compromise the financial integrity of the companies. Once again this argument is unfounded. In 1978 Congress adopted major legislation which cut the corporate tax rate from 48 percent to 46 percent, effective January 1, 1979. Thus, the question of refunding excess deferred taxes is by no means a new issue.

Table 7 displays partial results of a survey recently conducted by the NARUC which details how the states treated excess deferred taxes resulting from the 1978 Tax Act. Quite a variety of ratemaking treatments are represented in the table. What is perhaps most interesting is that very few states required the immediate flow through of the excess deferred taxes owed to customers. While past commission policy is not binding on current commissions and past practice is perhaps not a good barometer of future ratemaking, I think this survey at least "pokes a hole" in the utility argument that state commissions will immediately flow through to ratepayers any and all federal tax breaks they can get their hands on.

The key point it seems to me is that there is a critical difference between deferred and excess deferred taxes. In the first instance we are talking about money owed the federal government, while in the second we are talking about money owed customers. While there is a strong federal interest in having a measure of control over the timing of federal receipts, do not think it logically follows that Congress should dictate to the state commissions the timing of refunds legally owed to ratepayers.

The third argument used to defend this policy is that ratepayers would ultimately lose if the state commissions were allowed to

<table>
<thead>
<tr>
<th>State</th>
<th>Name of Agency</th>
<th>Rate Constant Period</th>
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<tbody>
<tr>
<td>Alabama PSC</td>
<td>ALABAMA PSC</td>
<td>Remaining Life</td>
</tr>
<tr>
<td>Alaska PUC</td>
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<td>Remaining Life</td>
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<td>Arkansas PSC</td>
<td>ARKANSAS PSC</td>
<td>1 Year</td>
</tr>
<tr>
<td>California PUC</td>
<td>CALIFORNIA PUC</td>
<td>10 Years</td>
</tr>
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<td>Colorado PUC</td>
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<td>CONNECTICUT DPC</td>
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<td>DELAWARE PSC</td>
<td>5 Years</td>
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<td>D.C. PSC</td>
<td>D.C. PSC</td>
<td>Remaining Life</td>
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<td>IOWA UR</td>
<td>NW 2-4 Years/Others-5 Years</td>
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<td>Kansas PSC</td>
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<td>Maryland PSC</td>
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<td>Massachusetts DPW</td>
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<td>No Refunds Permitted</td>
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<td>MISSISSIPPI PSC</td>
<td>3 Years</td>
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<td>3-5 Years</td>
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<td>Montana PSC</td>
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<td>NEVADA PSC</td>
<td>1 Year</td>
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<td>New Hampshire PUC</td>
<td>NEW HAMPSHIRE PUC</td>
<td>Elec-3 Years/Tel-4 Years</td>
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<td>NEW MEXICO PSC</td>
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<td>North Carolina PSC</td>
<td>NORTH CAROLINA PSC</td>
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<td>Oregon PSC</td>
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<td>WISCONSIN PSC</td>
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<tr>
<td>Wyoming PSC</td>
<td>WYOMING PSC</td>
<td>1 Year</td>
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Source: National Association of Regulatory Utility Commissioners (NARUC)

Table 7.
flow through the excess deferred taxes under a more rapid time frame, for the utilities would have to replace the lost capital at market rates, and who would pay the capital cost? The ratepayer, of course. Again I find this argument lacking in that many utilities (admittedly not all) are today rather "flush," particularly the electric utilities, who are holding many billions more in cash and temporary cash investments than they did just five years ago.

Table 8 shows the difference between what the major electric companies had in cash on hand and temporary cash investments as of 1985 versus 1980. The figures are, respectively, roughly $2 billion versus more than $6 billion. A closer comparison of the total 1985 cash versus the excess deferred taxes owed to ratepayers shows the wide disparity between the current cash position of the various companies, but quite a number could pay off their debt to ratepayers in rather short order.

Consider Consolidated Edison of New York as a case in point. In 1980 it held roughly $300 million in cash and temporary cash investments. By 1985 this figure had ballooned to more than $850 million. Its debt to ratepayers of a mere $150 million is paltry by comparison. I see absolutely no reason why Con Ed, with the highest electric rates in the nation and the highest cash balances of any electric utility in the nation, should not be compelled to pay off its debt to ratepayers in a more rapid manner than that required by the new tax law.

One word of caution is in order with respect to Table 8. Cash balances calculated at year-end are not in and of themselves a satisfactory measure of the financial strength of any company. The point I am making is merely that many utilities today, particularly electric are churning out sizable cash profits, which in turn are being reinvested in everything from real estate, to baseball teams, to parking lots, to insurance companies, to God knows what else, that could more appropriately be used to pay off this debt to ratepayers in a more timely manner. Clearly, state commissioners ought to have the ability to exercise control over this matter, particularly given the amount of dollars involved.

It is interesting to note that the Financial Accounting Standards Board (FASB) has entered the debate. The FASB is the professional society which determines acceptable and permissible accounting practices binding on the profession for the preparation and publication of financial statements. In an exposure draft is-
issued on September 2, 1986, relating to the proper accounting for income taxes, the FASB holds that companies should show the effect of tax rate changes immediately, in the first year. In other words, corporations (including public utility companies) will have to adjust the deferred tax amounts on their balance sheets to show the effect of the cut in the corporate rate even though the ratepayers will not receive their refunds for many years to come.

In shorthand this is called having your cake and eating it too! The business press, including Business Week and the Wall Street Journal, has already published articles noting this windfall to public utilities.

Perhaps more significant is the fact that a key FASB staffer who spoke to the NARUC staff Subcommittee on Accounts in Albuquerque speculated that this new FASB policy on deferred taxes could well spur Congress to amend the tax law to conform with generally accepted accounting principles.

The Investment Tax Credit Windfall

A second major issue in federal tax policy that has been a bone of contention for many years has been the federally prescribed ratemaking treatment of the investment tax credit. I think it is fair to say that many in regulatory circles were only too pleased to see the credit abolished as a major element of the tax reform package. No other provision of the Internal Revenue Code has caused greater confiscation of ratepayer dollars than section 46(f) of the code, which details permissible accounting mechanisms for the investment tax credit for rate-regulated enterprises.

The issue is significant and is currently causing utility rates nationally to be significantly higher than they would otherwise be were it not for the restrictive language of this section of the code.

The technical problem with the current normalization provisions of the code can probably best be seen by way of a simplistic, hypothetical example: Assume a utility purchases a $10,000 asset. It qualifies for a 10 percent ITC, so the company is entitled to an immediate $1,000 reduction in the federal taxes it would otherwise owe. The true cost of the asset is thus not $10,000 but $9,000 because the federal government has chipped in a $1,000 zero-cost capital subsidy. For ratemaking purposes the tax law requires that this subsidy be recognized only gradually or "ratably" over the regulatory life of the asset. For most utilities, which use so-called
Normalization or Conflagration?

option 2 normalization, this involves a simple annual reduction to the ratebase in an amount equal to a consistent fractional amount of the value of the credit received.

If Congress had stopped here, the ratepayer would have no reason to complain; Congress has merely provided a zero-cost capital subsidy to the utility which will be gradually flowed through to the ratepayer over the lifetime of the asset. Needless to say, Congress did not stop here. It went the next step and mandated that the unamortized ITCs—that portion of the credit not yet flowed through to customers—must be included in the ratebase and provided a full rate of return thereon.

The question we keep bringing to Congress is: What is the cost of the ITC to the utility? The answer is simple: The ITC has no cost. It is in every sense of the word a capital subsidy provided without cost to the recipient utility. Thus, it defies logic to require ratepayers to pay a rate of return on capital that has no cost.

The Department of the Treasury under both Presidents Carter and Reagan, the NARUC, the Congressional Research Service, indeed, all parties to this debate with the obvious exception of the utility lobby have testified any number of times before the congressional committees and have brought this technical error to the attention of Congress. Indeed, when the Reagan administration first took office in 1981 it shortly thereafter submitted its Economic Recovery Tax Act, and the original version contained language which would have cleaned up this problem. Needless to say, that was quickly excised from the bill at the request of the utility lobby and has not surfaced since.

What is at stake is significant. In the electric and telephone industries alone, well over $25 billion of accumulated deferred ITCs are on the books of the utilities and, accordingly, in the ratebase earning a full rate of return.

With the demise of the ITC under the new tax law, there is a temptation to assume that the problem has gone away. Unfortunately, nothing could be farther from the truth, because the unamortized ITC balances will be on the utilities books and in the ratebase for decades to come unless Congress acts to correct this inequity.

Assuming an 11-12 percent average overall rate of return on ratebase, which includes of course the $25 billion in unamortized ITC’s mentioned earlier, one can readily see that the nation’s pub-

lic utilities are clearly enjoying a windfall of enormous proportions.

Commissioner Charles Stalon, formerly of the Illinois Commerce Commission and now of the FERC, presented a paper to the NARUC annual convention a few years ago and called on Congress to correct this longstanding technical problem in the tax code. According to Stalon, “current ratemaking treatment of ITCs and the growing magnitude of unamortized ITCs will combine to destroy the public respect necessary for survival of State PUCs and, perhaps, the necessary public respect for survival of investor-owned utilities, and now is the time for State regulators to renew their call to Congress to modify the ratemaking treatment for ITCs.” The central thesis of Stalon’s paper is that in the course of the ratesetting process regulators are given a wide range of opinions as to the “correct” allowed rate of return on equity. A band of discretion of roughly 100 basis points or more generally exists between the high and low reasonable estimates for the correct allowable rate of return.

The regulator could thus choose an allowed rate in the low end of the scale in order to offset the inappropriate inclusion of the ITCs in ratebase. Note that the regulator would violate the normalization requirements if he explicitly made a rate-of-return adjustment based on the ITC inclusion. Nevertheless, the shrewd regulator could offset the ITC by cutting the allowed ROR. After a number of years, however, even this quasi-legal technique would fail in that ITC balances have grown so rapidly and are now so dramatically distorting the ROR actually earned that even this adjustment will fail to make the ratepayer whole. In 1986 the IRS did promulgate a vitally important rulemaking with respect to the ITC, and I urge all state commissions to take full advantage of it if they have not done so already. I am referring to the IRS final rule on the use of interest synchronization which was published in the Federal Register on May 22, 1986. NARUC was an active participant in this rulemaking and submitted written comments as well as oral testimony during a public hearing conducted during August 1985.

In essence, the new rule declares that a ratemaking technique already in use in quite a number of states is permissible and does not violate the normalization requirements of the code. More specifically, some state commissions were setting rates on the basis that, because the law required the ITC to earn a full rate of return,
it logically follows that the absence of the ITC would require the utilities to go to the capital markets and raise capital in a ratio roughly equivalent to its existing capitalization structure. Following through on this logic, if a utility had a 50 percent debt ratio, then 50 percent of the unamortized ITCs on the books represent debt which the utility has replaced with the federal capital subsidy. Accordingly, the commission should be allowed to impute an interest expense to this capital. The net result of this adjustment is the calculation of a higher interest expense for the utility and, accordingly, a higher interest deduction for federal tax purposes, which results in a lower federal tax obligation and ultimately a lower revenue requirement for the utility.

Needless to say, the IRS did not issue this rule without undergoing quite a fight with the utility interests, evident both in the number of written submissions filed and in the number of participants in the public hearing. The telephone lobby went so far as to attempt to reverse this rule as part of the new tax bill. The U.S. Telephone Association, never pleased with the rule from day one, pulled out all the stops in a last-ditch effort to reverse the IRS on this issue. Fortunately, Congress, for whatever reason, did not heed the advice of the telephone lobbyists, and the rule stands.

I urge state commission to look at this new rule and take advantage of the economic benefits of interest synchronization. NARUC did a survey on this topic a few years ago and found that roughly half the states were using interest synchronization. Presumably, many more are now taking advantage of this ratemaking device since promulgation of the rule. I know, for example, that the California PUC has adopted the practice.

Taxability of Unbilled Revenues

The next issue I would like to discuss is the taxability of so-called unbilled revenues. This is a matter over which there has been considerable debate—not to mention litigation—in recent years.

The IRS, since at least a 1972 revenue ruling, has allowed a variation of the accrual method of accounting known as "cycle meter reading." If the meter reading date falls within the current taxable year, the income attributable to utility services provided on or before the reading date is included in gross taxable income in that year. Utility services provided to customers within the current taxable year but after the last meter reading date were not recognized as taxable income until the following year.

This marked a substantial departure from traditional accrual accounting and provided a benefit to both companies and ratepayers. Generally, income is taxable when earned, regardless of when the cash revenues are actually received. The company benefited by an improved cash flow situation in that the taxes on unbilled revenues were not payable until the following year, when the cash revenues were received, even though the expenses associated with the production of those services were deductible the previous year. Ratepayers benefited in the same manner as they benefit from the deferral of tax obligations resulting from accelerated depreciation, that is, from an interest-free source of capital to the utility.

This issue came to a head in 1986 when the Orange and Rockland Utilities Co. of New York prevailed in the tax court over the IRS in its effort to expand upon existing practices of accounting for unbilled revenues. Apparently, the IRS has now gained its "sweet revenge" over Orange & Rockland, not to mention all other public utilities, by prevailing on Congress to require that unbilled revenues be currently taxable in the year earned. The net effect of this provision is to require an estimate of the income attributable to those utility services provided during the current taxable year but after the final meter reading date of the year. In short, this provides new funds to the federal Treasury at a time when it is scraping around for revenues, and thus this new provision was rather easy to sell to Congress.

Contributions in Aid of Construction

Another provision of the 1986 Tax Reform Act that will prove painful to both public utility stockholders and investors is the one relating to contributions in aid of construction, an issue of great importance to the water industry. Section 118(b) of the former tax law provided that gross taxable income does not include any contribution to capital of the utility.

In order to be eligible to be treated as contributed property, the money or property must be spent for the intended purpose within a given time, and the property may not be included in the utility's ratebase for ratemaking purposes. The new tax law deletes this tax preference. The problem is that as developers of residential housing tracts expand into underdeveloped areas, extensions of
the water service systems are necessary. Water companies have traditionally required the developer, or new homeowner, or both to pay for these extensions and then contribute to the utility.

Given that contributed property is now taxable income as received by the utility, the question arises over who should pay for the tax consequences of these extensions. In a recent decision before the Missouri Public Service Commission the commission ordered the developer to pay the income taxes which would be owed by the utility as a result of his contribution, less the present value of any tax benefits which the utility may be provided due to the fact that the contributed property may now be depreciated for income tax purposes. This approach places the burden squarely on the cost causeur. However, other states are exploring other approaches to this new tax dilemma.

A rate analyst of the Missouri commission informed me that they are now looking at a second approach. The developer would loan the utility the amount equal to the tax on the rate base, and the loan would be repaid over ten years, with principal and interest paid at the end of each year. To the extent that loan repayments are in excess of the tax savings realized by the utility, that amount would be added to ratebase. I am not sure of all the mechanics of this approach, but the point is that a number of states are concerned that water utility companies, particularly the smaller ones, will not be able to afford this new tax and have the wherewithal to build plant at the same time.

Where this is all leading I do not know, but suffice it to say that the commissions will be examining a host of innovative financing approaches in an effort to deal with this new tax problem.

Corporate Minimum Tax

One other issue warrants our attention, the new corporate minimum tax. Table 9 and 10 contain data on the effective tax rates paid by the nation's electric and natural gas pipeline industries. Unfortunately, time did not permit the preparation of a similar schedule for the telephone industry.

Without going into the complexities of the schedule itself, let me briefly state that the schedule purports to show the net effective tax rate paid by the two industries as adjusted for noncash earnings, such as the debt and equity components of AFUDC and as adjusted for the effects of interperiod tax allocations, which
### Normalization or Conflation?

**GAS PIPELINE INDUSTRY EFFECTIVE TAX RATE**

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<th>YEAR</th>
<th>BEFORE</th>
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<th>EFFECTIVE</th>
<th>BEFORE</th>
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<td>27.6</td>
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*Source: Kiefer utility tax model using data provided by the U.S. Energy Information Administration of the U.S. Department of Energy. For a thorough review of this tax model refer to: "The Diminishing Federal Tax Burden of the Public Utilities; Measurement and Analysis", by Donald W. Kiefer; National Tax Journal: December, 1980; p. 391.*

Table 10.

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Michael Foley

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as discussed at length earlier allow the utilities to collect more from customers year after year than they actually have to pay to the federal government. Accordingly, the final column of numbers shows the net effective tax rate paid by the industries to the Treasury.

One will note that in both the electric and gas pipeline industries the net effective tax rate paid bottomed out in 1981, at 7.4 percent for electrics and 10.9 percent in the gas pipeline industry. The effective tax rates for both industries have been generally rising since then due to at least three factors: (1) the dilution in depreciation and ITC benefits as a result of the 1982 TEFRA Tax Act; (2) a general slowdown in new capital plant additions, which of course contribute to an increase in the deferral of current federal taxes; and (3) a strong decrease in noncash earnings, again resulting from the slowdown in the increase in new capital plant additions.

While the effective tax rate for both industries has been rising, there still remains a rather wide gulf between the 46 percent corporate tax rate and the actual tax rate paid by the utility companies. This gulf is particularly wide in the electric industry, where in 1984 the effective tax rate was only 18.5 percent, or roughly 27 percent or more below the statutory corporate tax rate of 46 percent. These and similar data for other large capital-intensive industries have prompted Congress to toughen the corporate minimum tax.

A brief model of how the corporate minimum tax works is shown below. The mechanics of the new corporate minimum tax are rather complex, and I will not embarrass myself by attempting to explain the details. However, at least one point is in order: Congress enacted a tough minimum tax because it felt the gulf between the statutory tax rate and the actual net effective tax rate in certain industries was far too wide.

Quite a number of electric utilities will be caught by the new minimum tax, and Duquesne Light Co. and Philadelphia Electric have already filed for rate increases to reflect the effects. It seems to me that to set utility rates on the basis of the minimum tax is to defeat its very purpose. Once again, the utilities want to have their cake and eat it, too. Is it not enough that utilities are being allowed to hold onto some $515 billion of ratepayers' money and flow it back only under an extremely slow time frame. Now they
ALTERNATIVE MINIMUM TAX CALCULATION

TAXABLE INCOME
+ TAX PREFERENCES
ALTERNATIVE MINIMUM TAXABLE INCOME
- EXEMPTION AMOUNT
ALTERNATIVE MINIMUM TAX BASE
\[
\times 20\%
\]
ALTERNATIVE MINIMUM TAX

Exhibit 1.

are coming in to the commissions and arguing that ratepayers ought to be hit with yet another round of rate increases just to cover the additional tax burden utilities will have to pay under the minimum tax.

More important, however, is the fact that utilities are now put in a position where they are arguing against themselves. When they were earning huge tax deferrals under the lucrative depreciation schedules of the Economic Recovery Tax Act and therefore building up their deferred tax balances industrywide basis by many billions of dollars per year, the utilities would fend off the consumerists by saying that one need not worry about ratepayers overpaying the federal taxes component of the revenue requirement because eventually the timing differences would reverse, and the taxes would be paid. Now that the corporate minimum tax has advanced the day when it is time to pay the piper, the utilities have gone charging off to their state commissions asking dollar-for-dollar recovery of the new tax burden. You cannot have it both ways.

Conclusion

It is said there are only two sure things in life—death and taxes. I submit that so long as Congress continues to usurp the role of those who have the legal obligation of setting utility rates by way of gerrymandering the federal tax code there will be a third sure thing in life: The prices we pay for basic public utility services will continue to be higher than they need to be due to an excessive federal tax component in the revenue requirement. Perhaps that explains why utilities love “paying” federal taxes.

Notes
Obsolescence and an Economic Model of Equipment Lives and Depreciation

Paul S. Brandon

Depreciation is a dull subject, at least as generally calculated by regulated firms and commissions. In caricature, traditional depreciation techniques rely on historical equipment retirement data, which is like driving a car down the freeway with the windshield covered up, only being able to see what you have passed.

Astronomy gives us another analogy. Long ago, people recorded regularities in the movement of the sun, moon, planets, and stars. They could accurately predict their motions, but their approach was simply analysis of historical data. For centuries, they had no model that explained why celestial bodies moved the way they did; the ancient astronomers did not know the gravitational theory. So if someone had asked them to specify the trajectory of a rocket into orbit, they could not have answered. Similarly, reliance on historical telecommunications retirement data may yield overestimated lives of today's equipment because of major changes.

Note: The views expressed in this paper are the author's, not those of Bell Communications Research or its owners.

Motivations for a New Approach

I noted one problem with traditional depreciation methods which motivated me to develop a new approach; namely, previous methods have not dealt adequately with significant industry changes. A second problem is that a central assumption of mortality analysis is generally false, at least in the telecommunications industry.

For the mortality approach to be the most useful, the expected remaining life of equipment should be affected more by its physical age than by its vintage. Yet, telecommunications data tend to demonstrate the opposite. Figure 1 is a typical example. Each curve represents the gross investment history of a different vintage of large step-by-step switching equipment, an electromechanical technology. Most of these switches were removed from service in only four years—1974 through 1977—regardless of when they were first installed. The technology had become obsolete. The retirement pattern is more like mass extinction than individual mortality. The new economic model can predict such obsolescence and resulting mass retirements.

A third motivation for a new approach is illustrated by the following example: The tandem switch in New York Telephone's Garden City central office had worked well for thirteen years, and it was still switching calls as it always had. Yet, New York Telephone spent several million dollars to replace this 44 crossbar switch with a new digital electronic switching system. There is nothing unusual about this. Telephone companies all over the country are sending electromechanical switches into retirement.
But why? If an old switch is not worn out, why replace it? Some regulatory commissioners are asking that question.

The electromechanical switches are not worn out, but technological and market changes have made most of them obsolete. An economic model can explain why it pays to replace them. Traditional depreciation methods predict when they will be retired but cannot explain why.

**An Economic Model of Equipment Lives and Depreciation**

Previous technologies such as electromechanical switches become obsolete primarily in three ways. First, the digital switching systems that replace them will cost much less to operate and maintain. Second, the new switches will enable telephone companies to offer customers equal access and a broader range of services, for example, custom-calling services such as call forwarding, thus generating more revenue than the old switches could. In some cases, the new technology’s greater capabilities enable revenues to be retained that would otherwise be lost to competitive offerings. Third, by investing in a digital switch now, a telephone company will avoid future investments in the signal-conversion equipment needed to adapt electromechanical and analog electronic switches to the increasingly digital network. Over the life of the new switching system, these reduced expenses, increased revenues, and avoided investments will more than compensate for its purchase. The replacement will make the company’s customers, on the whole, economically better off. That scenario applies if the economic life of a switch or other equipment is over. The model I have developed estimates when a piece of equipment will come to the end of its economic life. It selects the replacement date so as to minimize the present discounted value of all future net expenditures. At that date, the replacement’s lower maintenance and operating expense, higher revenues, and so forth, will exactly pay the interest and principal for a loan to finance its purchase.

The model’s main inputs for the existing equipment are its maintenance and operating expense, future right-to-use fees and training expenses, its salvage value, and the rate at which those variables are changing. The model also requires the maintenance and operating expense, installed cost, right-to-use fees and training expenses, salvage value, and greater revenue-generating capability of today’s best alternative technology, as well as the rate at which those variables will change over time for that technology and from that technology to the next.

Of course, people may argue about the forecasts of such variables, but at least they would be arguing about the right things. Although a comprehensive discussion of such forecasts is beyond the scope of this paper, one example of data may be helpful. Figure 2 shows what has happened to the installed costs per line for large switching systems from 1965 to 1986. In constant dollars, the cost per line fell about 60 percent, roughly 5 percent per year compounded. The rate of decline accelerated after 1973. From then until 1986, the compound annual cost decrease was 7 percent. Such data can be used to help forecast future installed switch costs.

My emphasis here is on economic equipment lives, and one
HISTORICAL LOCAL SWITCHING COST

![Graph showing historical local switching cost](image)

Figure 2.

could use the economic model just to calculate lives, but it also permits one to calculate the economic value of equipment for each year of its economic life. Companies in some industries can measure the value of existing plant in ways that do not apply to the telecommunications industry. A trucking company, for example, can use the active resale market in trucks to determine the value of its fleet. There is no comparable resale market for switching systems and buried cable, so the going price of, say, a 1977-vintage switch cannot be used as a reference point. Instead, the economic value of equipment must be imputed. The imputed value is the answer to a deceptively simple question: How much more would it cost to start from scratch with the best available technology than to continue with the existing technology? The model calculates the present discounted value of capital and expenses required to install, operate, and maintain the best technology available and its subsequent replacements, less the additional revenues that new equipment would provide. Taking a similar set of factors into account, it calculates the present discounted value of expenditures for the alternative, sticking with the existing plant. The difference between the present value of expenditures for the two scenarios is the economic value of the existing plant. The value is calculated for each year of the existing equipment's remaining economic life. The economic depreciation is defined as the reduction in economic value from one year to the next.

Illustrative Model Results and Conclusion

For telecommunications central office equipment, economic depreciation generally follows an accelerated pattern. Figure 3 shows results of an illustrative model run for a large switching system. The economic value erodes more rapidly during the first several years than it does for the remainder of its life. The degree and pattern of technological change affect the pattern of economic depreciation, but the dominant factor yielding the accelerated pattern is the short period of tax depreciation. Each year after installation is one less year for which the firm can look forward to receiving the positive cash flow from tax depreciation; therefore, the present discounted value of net expenditures for the existing plant rises rapidly for the first several years, causing its economic value to fall rapidly. A second observation from Figure 3 is that, because the economic benefits of new technology compel the replacement of existing plant regardless of age, later installations of an old technology lose value more rapidly than did the earlier installations. Also note that the later installations will be replaced at an earlier age, but at the same date. Therefore, if a discrete technology had been installed for several years, then the economic model can indeed predict an avalanche of retirements.

In this era of rapid industry change, the economic life and depreciation model can solve several problems with traditional methods. The economic model can handle the new industry conditions even if they are significantly changed from a few years ago. The model can predict an avalanche of retirements that is typical of telecommunications equipment. The new model can explain why obsolete plant should be replaced to make customers as a whole better off. Finally, as an economist, I am much more comfortable using a model that emulates actual decision processes as opposed to merely analyzing data without a theory.
ILLUSTRATIVE ECONOMIC VALUE

1977 AND 1982 INSTALLATIONS

1982 INSTALLATION

1977 INSTALLATION

ECONOMIC VALUE (% OF BOOK)

YEAR

77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95

Figure 3.

Notes

1. GTE and I independently developed economic depreciation models. The two are largely consistent but differ in the degree of detail. GTE's model is described in T. D. Robinson, "An Economist's Perspective on Depreciation," Telephony, August 11, 1986, pp. 63-68. An early version of my model is described in "Technological and Market Obsolescence of Telephone Network Equipment" June, 1986, pp. 30-41 and Appendix 1, Bellcore document #ST-BEL-000029.

2. The important question of how the economic benefits of new technology should be shared among different categories of customers is beyond the scope of this paper.

3. The installed costs are the "E&F" expenditures—engineered, furnished, and installed. Note that the costs are based on planning prices. They are not necessarily equal to prices which might be paid by an operating telephone company. For example, these planning prices do not consider the possibility of volume discounts. These prices should not be used for vendor selection.


5. I mean to imply no recommendation here about what the pattern of book depreciation should be. A crucial element whose discussion is left for another time is what happens to the deferred tax accounts.
Comments

James S. Pignatelli

William Ahern has likened the regulatory process with regard to avoided cost and QF development as a “wild turkey shoot.” We liken the regulatory process and the court system in the early 1960s and 1970s in California to a breakfast cereal—it is a bunch of fruits and nuts surrounded by flakes. That group is, depending on the expletive one likes to use, the mother or the father of a lot of the normalization restrictions to which Michael Foley takes offense, the actions of the court system and the regulatory system with regard to PacTel and the Bell network, as well as the gas companies and the Pacific Gas and Electric Company.

So, we do feel uniquely situated to discuss some of the issues that Foley said. I promise I will not debate normalization or flow through. I was pleased that Foley recognized the validity and the propriety in the ratemaking process of comprehensive interperiod tax allocation or normalization. He took exception to the treatment of the excess reserve, which I will discuss further. I cannot let his statement that “utilities love income taxes” go by without at least a little defense. I do not think there is a utility executive who can state that he loves paying income taxes, either personally or from his customers’ funds, because he has to recover those income taxes from the customer. Peter Stark’s misguided attempts to replace the income tax with an excise or special tax on utilities would, I believe, segregate utilities from the mainstream of taxpayers. And once segregated from the mainstream, one is fair game for increases or treatment leading to a higher tax burden that, if one is included in the mainstream.

I think Donald Kiefer and Foley have done a good job of summarizing what has been referred to as the most comprehensive tax legislation in forty years. It is so comprehensive that the Tax Reform Act of 1986 will be renamed the Internal Revenue Code of 1986; we can no longer say “Internal Revenue Code of 1954 as amended and superseded, and so forth.” Now it is the Internal Revenue Code of 1986. Simplification? No. This act did not simplify. I think Kiefer’s point is that we are now going to maintain comprehensive records, financial tax records, alternative minimum tax records, and ratemaking records. Whether those four sets of books will ever meet is still a question. I do not know. It is going to be interesting.

Every time we have a tax act, it is really the accountants’ and lawyers’ retirement fund being built up, and this one is no exception. Reduction? This tax act did not reduce taxes; it shifted the burden of taxes, and I think this is something Kiefer and Foley might have discussed. With the shifting of the burden of taxes, what is the longevity of the rates? Will we see 34 percent? We will see a blended rate, perhaps 40 percent. I question, first, whether we will see 34 percent as the rate for a year and, second, if we do, how long it will last. That has a lot of implications for excess taxes. If one assumes that the tax rates are going to go up, those excess taxes, deferred taxes, become deficient. Who should bear the burden of the deferred?

Just to put it in perspective, in the electric utility industry, we project a one or two percent reduction in utility rates because of the reduced tax rate. We expect this to last into the mid-1990s, at which time we will start to incur higher taxes because of the longer lives in the other provisions of the code. But along with that—and this is what I would like to hear Kiefer comment on—how about the effect on the financial condition of the utilities? Once again, in the electric industry we project reduced cash flow in the neigh-
borhood of 5–10 percent from what it would have been through the mid-1990s and, after about 1995, a reduced cash flow of about 25 percent. That concerns me because that is the time we probably will embark, depending upon the success of cogeneration and other measures, on long-term construction programs. Aggravating the reduced cash flow, we will have lower pretax coverage ratios. That is going to affect debt costs, potentially hastening the day of increasing the equity return Foley indicated. Aggravating that may be a required thickening in the equity ratio to compensate for the lower interest coverages.

I think we have a challenge in implementing this tax action. In the ratemaking process we have to avoid short-term aberrations in rates; that is why I am very interested in the assessment of the longevity of the rate. If it is a very short-lived tax act and we see increased revenue requirements shortly, should we act speedily in reducing rates at this time and producing a momentary dip? I believe that long-term rate stability is a primary objective of regulation. In addition, we must—and this is something that runs through all the specific items that Kiefer and Foley discussed, which I am going to examine briefly—we must ensure equity to our customers. We must provide the correct customer with the correct tax benefits which arise from the payments he makes—and this gets into the disagreement on excess tax reserves between Foley and Kiefer. Looking at just the six specific items, the tax reserves being the most contentious, I agree with Kiefer that the excess tax reserve should be flowed through over the life. He cited the congressional intent, the maintenance of capital, and the consistency with unregulated business as rationales for this. I would add to that the equitable treatment of ratepayers and refer to what Kiefer said about this being a grant when one changes the tax rate. To avoid a short-term aberration in rates by immediately flowing through that grant, I feel it is better to flow it through over the life and therefore not create that inequity. Foley argues that Congress should not set ratemaking policy but should leave that to the regulators. I hear back to the cereal—the reason it is there is because the regulators, primarily in my home state, created and aggravated a situation which the courts kept sending back to the regulators. Regulators attempted to treat it correctly in the late 1960s, but Congress felt compelled to take action to restrict these benefits and their availability contingent on the ratemaking process.

There is one other interesting subject I wish would have been discussed more, the exposure draft of the accountants’ current thinking on the reflection of taxes in financials. Foley alluded to it, but I think he missed one very important point, that the exposure draft requires one to set forth the liability method. He focused on the excess reserve due to the rate decrease, and I think he quantified that at $8 million, but he did not focus on the liability which currently exists in the utility industry for previously flowed through taxes, which were immediately flowed through to the ratepayer, especially in California, prior to 1982, and the tremendous liability that currently sits inherently on our books. Maybe the excess reserves about which Foley is concerned should be offset against the deficiency that currently sits on our books, because that is a liability for which the ratepayer is going to have to make us whole.

Foley also commented on the investment tax credit and his exception to whether it should be used to offset ratebase. That is an ongoing disagreement. I would only refer to the congressional intent behind the restrictions, the three options with regard to investment credit, where I believe Congress felt there were dual benefits that should be shared between the stockholders and the consumers of electric service. I think that was covered in the original legislation.

As to Kiefer’s discussion of accelerated depreciation, I would like to know how, comparatively, QFs or other third-party generation projects now stack up with regard to depreciation compared to conventional electric plants. This tax act has removed some of the special credits and accelerated life that third parties previously enjoyed. I would have liked to have heard something from Kiefer on that.

With regard to the alternative minimum tax, there will now be two sets of books, which is going to be a severe pain. I think both papers missed the impact on the AMT which will come from those utilities with large fuel adjustment clauses, because they will have a high aberration one year to the next depending on the under- or overcollection in their fuel balancing accounts. This will create the possibility of an AMT between periods.

Concerning the absolute payment of the AMT, I agree with Foley that it is an error to seek from the regulator the actual AMT.
Test year ratemaking should avoid situations where the AMT is an expected item, but I believe we have to come to an agreement with the regulator to treat the AMT as, perhaps, a prepaid tax item or a negative deferred tax, that is, something on which the utility and the shareholders earn a return, because they have put that money out in advance of collecting it. That is something which has to be covered very carefully.

Kiefer also mentioned unbilled revenues. The effect of these is just a further aggravation of cash flow.

Contributions in aid of construction are the last specific item on which both Kiefer and Foley touched. It is interesting that they came up with two different rate treatments. Kiefer threw it off the cuff, suggesting perhaps contributions should be included in ratebase. I do not see that happening. Increasing the current cost of producing power by a tax which comes from somebody connecting up to our system—I just do not know that the ratepayer will allow that. Foley, in contrast, suggested a gross-up with a discount for the present value of the future tax benefits, charging the person who is causing the increase. I have sympathy with that approach, even though I know the QFs and the building trades are going to object to it, but I am concerned if that method is used. Who stands the risk of loss if the discount factor changes? Is it the utility who "eats that difference" out in the future—they certainly will not get it back from the developer. So taxation of that element is going to create ratemaking opportunities.

I do not want to slight Paul Brandon. I have great sympathy for economic depreciation. I believe it facilitates prudent investment decisions. However, I think there are practical problems. The accountants will say that depreciation is not an evaluation system. It is purely a cost allocation system, and all it is attempting to do is make a systematic and rational allocation of cost between periods. When one switches to economic depreciation, one is establishing it based on value, and I think there would have to be a great deal of education in the accounting profession to achieve any changed economic depreciation. It also gives me a little bit of a problem, since I am rather on the other side of the situation. Brandon's concern is technology outstripping inflation, which for large electric utilities is generally happening at this time, and in fact what we have run into is trended ratebase approaches which would defer depreciation by capitalizing it. This is perhaps the opposite side of the coin from what Brandon is talking about. The accountants have a lot of problems with that, because it means starting to carry an asset on the books at a higher than cost. I think the application of Brandon's method in the ratemaking process would be subject to considerable contention. There would be arguments over discount rate, over future O&M. There is much volatility in the factors on which return assumptions are based. Changes in tax rates would change the evaluation of alternatives. The ratemaking process is contentious enough in the use of depreciation based on actual data, and this would add a new wrinkle. That is not to say I do not think it is useful; I think we should use this type of modeling in establishing recovery periods.

In conclusion, I think taxes—whether it be depreciation or an actual tax—should be treated in rates in a way that strives for some stability and intergenerational equity. To me that is comprehensive interperiod tax allocation. I also would suggest that in about two years we have a panel on how to treat the tax rate increase and its effect on depreciation reserves.