Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing

Edited by
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Proceedings of the Institute of Public Utilities
Fifteenth Annual Conference

1984
MSU Public Utilities Papers

Institute of Public Utilities
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East Lansing
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The papers and comments contained herein are the final versions of presentations at the Fifteenth Annual Conference of the Institute of Public Utilities held in Williamsburg, Virginia, on December 12, 13, and 14, 1983. This particular conference emphasized the changing patterns of regulation, markets, and technology in the electricity, gas, and telecommunications sectors, with particular focus on the consequences for pricing practices. In essence, the theme of the 1983 conference was similar to the themes of the past several conferences in focusing on how public utilities and regulatory agencies are adapting to increased uncertainty, unstable environments, and changing external forces.

The papers and comments are derived from eleven conference sessions which addressed (1) an overview of new pricing issues in public utility industries, (2) adjustments to new market structures in telecommunications, (3) consumer responses to changing price patterns in telecommunications, (4) issues in local telephone exchange pricing, (5) universal telephone service and the access charge debate, (6) regulatory treatment of excess capacity, high cost plant, and premature retirements in electricity, (7) integration of high cost plant and excess capacity into electricity rate structures, (8) nuclear power issues and the problem of social costs, (9) changing market boundaries, new entry, and interfuel rivalry in natural gas, (10) the potential effect of imposing common or contract carrier status on pipelines, and (11) international issues in natural gas pricing.

In an overview of new pricing issues, three papers address specific pricing issues in electricity, natural gas, and...
telecommunications. Richard A. Abdo presents a universal theory of electricity pricing. George R. Hall discusses changing pricing policies in natural gas; and James H. Alleman and Leland W. Schmidt address telecommunications pricing in an unstable regulatory environment.

In a telecommunications section dealing with adjustments to new market structures, five papers address bypass and other current regulatory issues. Maurice W. Lamb analyzes bypass as a competitive alternative; David S. Brevitz provides a framework for evaluating the threat of bypass in regulatory proceedings; Basil J. Bertzke discusses the effect of the AT&T divestiture on the independent telephone companies; Andrew J. Margeson analyzes new entry and intercity competition after divestiture; and Charles A. Zieliinski assesses post-divestiture state regulation.

In a telecommunications section focusing on consumer responses to changing price patterns, A. Noel Doherty presents empirical estimates of demand price elasticities of local service; Susan E. Grove and Scott Stephen analyze consumer response to interstate rate changes; Lewis J. Perl presents an econometric analysis of the demand for access; and John Chan examines the demand for residential terminal equipment.

In a telecommunications section involving local exchange pricing, Edward C. Beaulieu evaluates the efficiency gains from usage sensitive pricing; James R. Green and Charles J. Zarkadas discuss the issues linked to optional local measured service; and John K. Holay analyzes the integration of local and toll rates.

In a final telecommunications section, four papers address the debate regarding universal service and access charges. Kenneth L. Gordon and John H. Harper discuss FCC rate revision and their effect on universal service; Michael D. Peckovit, Nina W. Cornell, and Stephen R. Brenner focus on the gap between access charge theory and implementation; Richard Stonard evaluates access charge options for intrastate and interLATA services; and Brian P. Sullivan analyzes the distributional consequences of equal access.

Three papers address significant regulatory problems in the electric utility industry associated with the current environment of excess capacity, high cost plant, and plant abandonments. Basil L. Copeland, Jr., discusses ratemaking treatment regarding excess capacity; William M. Gallivan and Bruce T. Smith look at the regulatory challenges in handling major plant additions; and Richard J. Lurito and Bruce M. Louelle evaluate the economic and financial implications of alternative treatments of cancellations, abandonments, and premature retirements. These papers address the problems of integrating high cost plant and excess capacity into electricity rate structures. Miles D. Bidwell discusses optimal cost allocation as a means of avoiding rate shock; David K. Owens examines the effect of high cost plant on established ratemaking prac-

tices; and Kenneth D. Stofferahn analyzes the potential for employing demand elasticity in rate design as a method for dealing with excess capacity.

A final electricity section focuses on social cost and nuclear power issues. Jean-Paul Reiner assesses European nuclear power development; Howard F. Perry addresses the issues of financing and managing nuclear waste disposal; and Rob Brenner and Milton Russell examine the social cost issues in power generation.

Three papers address issues related to the emerging competition in natural gas, as exemplified by new entry and interfuel rivalry. Kenneth A. Williams looks at competitive responses by interstate pipelines; Virginia K. Sheffield presents an empirical study of natural gas price elasticities and their regulatory implications; and Julian M. Green examines interstate interfuel rivalry as a proxy for competition and regulation in the natural gas industry. Two papers address issues related to imposing common or contract carrier status on natural gas pipelines. Curtis A. Cramer evaluates the pipeline industry as a common or contract carrier in the context of benefit-cost analysis, and Catherine Good Abbott examines the future consequences of regulatory reform in the pipeline industry.

The concluding section of the volume looks at some international issues in natural gas. Roland Priddle examines the price relationship between Canada and the United States; Keith F. Palmer discusses producer incentives and gas contracts in competing countries; Asfaneh Mashayekhi compares pricing practices between developing and developed countries; and Gary J. Paglino focuses on the economic aspects of the Alaskan and Alaskan projects.


The administrative details in planning and conducting the conference were handled by Mrs. Virginia Michels. Her administrative performance helped produce a successful conference. In addition, Mrs. Michels monitored the publication process; she was assisted by Mrs. Audrey Rubner.
Part One:
An Overview of New Pricing Issues in Electricity, Natural Gas, and Telecommunications
UNIVERSAL THEORY OF ELECTRICITY PRICING

Richard A. Abdoo

Accepted theories of public utility pricing of electricity in the past were quite narrow in scope, usually single purpose and quite resistant to change. Although these theories were thought to be adequate in their time, changing patterns in regulation, markets, and technology have severely affected public utility pricing theory. The impact has been so extensive that it now demands an enlightened broadening of pricing theory to a comprehensive, or universal, theory capable of meeting the ever-shifting needs of informed ratepayers, progressive utilities, and enlightened regulators. It behooves all involved parties to demonstrate the flexibility and initiative necessary to implement and sustain a more universal pricing policy in the future, one that returns to consumers a sense of once again controlling their destiny, of controlling their energy usage and costs without necessarily compromising their lifestyle. In other words, we need a policy which provides customers the freedom they once had.

In this paper I wish to discuss the historical perspective of electricity pricing, the influences directing the course of electricity pricing over time, and the disruptions experienced recently at the close of the industry's first century. I will then offer my assessment of the new pricing issues facing us today, along with a suggestion of the opportunities they represent to the industry and the regulators.
Disorganized, Unregulated Pricing

The electric utility industry had its beginning on September 4, 1882, with the advent of Edison’s Pearl Street Station in downtown New York serving up to 80 customers with 400 lamps. In the early years, electricity was too expensive for the average customer of the day and was considered a luxury item. Costs were difficult to determine, and because most early light and power companies knew little about the economics of their business, they often sold electricity below cost.

In the late 1880s utilities could charge anything the market would bear. Rate setting was marked by experimentation and a lack of uniformity from company to company. Wisconsin Electric’s predecessor, the Milwaukee Electric Railway and Light Company, was certainly no exception. Rates included a daily flat rate for service and different rates based on the number of rooms in the house, the number of bulbs, and even the number of outlets. Customers did have choices in those early days, and they and the utilities were in a continual state of confusion due to the constantly changing rate schedules. It was not until 1897 that the first practical electric service meter enabled utilities to charge customers based on actual rather than potential usage.

The availability of metering allowed prices to be set to cover two costs. The price of the initial block of electricity was set to cover the fixed costs involved in meeting the maximum demand. The charge therefor was largely covered operating costs. The price for the first block was high but declined as the quantity sold increased—the advent of declining block rates.

During that era, the electric utilities pursued a low price policy. Low prices were either a result of not knowing the true costs or, more likely, of being sufficiently far-sighted to give up current profits for future gains, thus forcing out the competition. This led to “cut-throat competition” or “rate wars” in which competitors cut prices until only variable costs were covered. Customers enjoyed the short-lived advantage until the winner of the price war jacked up prices to recoup losses. Such was the confusion in pricing of the early years through 1900.

Regulated Pricing

A sense of order and sanity in ratemaking soon began to emerge across the nation. In 1907 the Railway Commission of Wisconsin was one of the first regulatory bodies to enter the picture. Its function was to regulate utilities and set utility rates as well as regulate railroads. The intent was to protect the public from rate wars and the resulting deterioration of utility service. In reality, the industry was regulated partly because of economics of scale, partly because of political needs, and partly to control competition.

The origin of regulation, therefore, may not simply be the inevitable result of a natural monopoly situation. Residential prices under regulation, however, continued their downward trend through World War II with the introduction of increasingly complex rate schedules.

Holding Company Pricing

Along with regulation of operating utilities came a centralization of ownership under the umbrella of the electric utility holding company, an unregulated entity. It was soon realized that taking control of a number of smaller systems and putting them together was profitable and facilitated raising money and engineering the best systems. The price for electricity fell, absolutely and relatively.

Stable Pricing Pattern (Declining)

Following the Great Depression, the industry assumed its present structure and entered on a era of high stability in both earnings and pricing. It looked forward to continued and sustained long-term growth with a high degree of confidence.

In retrospect, the postwar 1940s through the 1960s were “the good old days” in electric utility operation and pricing. Despite the rapid growth in demand, the industry moved to lower prices due to large part to economies of scale in power generation. Prices were designed to sell electricity. One way the industry experienced minimal need for rate relief, declining costs and prices, satisfied customers, and very acceptable returns for investors. With few operating problems and little need to question prevailing regulatory methods, few if any people were prepared to act quickly or to understand the problems that followed.

A watershed year for the industry was 1965: stock prices peaked, rate reductions were the greatest, finances were strong. There were, however, indications that all was not well in the electric utility industry. From 1965 to 1970, demand continued to increase while the price of electricity remained flat despite a sharp upturn in costs. The industry and regulators seemed not to realize that a fundamental change in costs was taking place. This led not only to an inability or unwillingness to raise prices but also to an accelerating deterioration in the financial condition of the industry. For the most part, pricing policy remained unchanged.

Increasing Prices

From 1970 into the 1980s, we saw rising prices for electricity. We attempted pricing our product to collect money
to keep our heads above water. Capital spending increased, fuel prices rose, the environmental and consumer movements grew stronger, customer hostility increased. Construction delays and escalating plant costs were the name of the game. Choice was taken from the customer.

Industry trends were toward a rising cost of capital, inadequate rate relief, an inability to raise productivity, a declining financial situation, and a general inability on the part of regulators and utility management to cope with the economic and societal problems at hand. Customers demanded the attitude that ratepayers were to which they were entitled. They then became frustrated by the fact that utilities had a monopoly on a service they regarded as a right, and there was little they could do about it. All the choice built into the system over the prior years was stripped away in this period of rising prices.

Four major events placed particular shocks on the industry as a whole: (1) The Northeast Blackout of 1965 highlighted the complacency into which management and regulators had fallen. (2) The OPEC oil embargo of 1973–1974 caused the industry to reel from the unexpected financial consequences of increased fuel cost and reduced sales triggered by rapid price increases. (3) Consolidated Edison omitted its common stock dividend in April 1974, helping to destroy the cornerstone of faith for investment in utilities, that the "dividend is safe and will be paid." (4) The nuclear accident at Three Mile Island on March 28, 1979, eliminated any respect about nuclear power and highlighted the ever-present risk of financial loss.

All in all, the industry and its pricing policies were in a state of turmoil and disarray.

**Recap of Past**

The electric utility industry is now a century old. It has grown to be the major support system for the nation's economy. It has seen extended periods of relatively stable, quite predictable growth unmarked by dramatic change. Prices declined for most of the period, with sharp increases near the end. Pricing policy went from the unresolved to the formalized, from the complex to the more simplified, from selling electricity and collecting revenue to stressing conservation. The industry went from fragmented competition to regulation, from continuing growth to stagnation, from financial strength to financial uncertainty. Regulation went from nothing, to benign, to confining, to frequently disruptive.

**Universal Theory of Electricity Pricing**

**The Second Century**

The first century saw challenges that were first technical and then political. The onset of the second century has not brought an end to those challenges but has brought a realization that the solution to them lies with our customers. The major problem facing utilities today is the customers' sense of threat, their sense of alienation and disconnection from the industry they once perceived as a given good. Dealing with those perceptions—helping customers with their energy-related needs, showing them how to buy and use kilowatt-hours more selectively and efficiently without compromising lifestyle--these are the most noted strategic challenges the industry faces today. A creative, new pricing policy must emerge if we are to meet and conquer these challenges.

**Pricing to Attain the Second Century Goal**

The ability to price our product in response to the rapidly changing environment experienced by both our customers and our companies will be the key to meeting our most strategic challenge: getting closer to our customers, meeting their wants and needs. This will require the ability to adapt quickly to the changes because there is no longer the luxury of long periods of stable operation during which one can ponder possible courses of action. Time and tide no longer wait for the electric utility industry. This requires a dramatic change in posture to one of being quick on the feet and alert in judgment in response to the changing environment.

The change in the electric utility will have to be considerable. The industry's reputation for "inertia," its indisposition to motion, exertion, or change, has traditionally been excused only by the reputation of the various regulatory bodies, which have been said to approach a state of rigor mortis. We have all experienced numerous instances of required changes taking place long after the horse has left the barn. Industry delay and institutional passivity on the part of regulators are hard facts of life in today's utility environment. This must change if we are to be successful.

Gaining the flexibility and freedom necessary for change must be a joint, synergistic effort on the part of the industry and its regulators. The electric utility industry must overcome its perceived "inertia" and prepare to serve its customers in the competitive world into which it is being carried. New ideas, rules, and concepts must be developed, tested, and implemented as rapidly as the environment demands.

Regulatory bodies, in turn, must overcome their tendencies toward rigor mortis and join in the search for effective and responsive methods of serving their constituents. Regulatory bodies will always be constrained, however, by the nature
of the constitutional process and can thus only respond up to a certain speed. Recognizing and built-in constraints, the regulatory bodies should strive to structure their regulations in such a manner as not to tightly restrict the ability of utilities to concentrate their efforts on particular areas of concern as the need arises. Only by recognizing that flexibility and freedom to adjust are mandatory in the 1980s and beyond can regulatory bodies truly meet the challenges of the second century.

**Universal Theory of Pricing**

Exploitation of this desired flexibility and freedom allows a move to more dynamic pricing policies. Customers have solidified their notions that they do not have freedom of choice in today's energy world. We must convince them of the contrary. Customers are more aware of what is going on in the utility business today than at any point in the past several decades, but they will still require extensive information as to their options and opportunities and must be convinced of the need to engage in two-way communication with the utilities.

Communication is the key to a successful pricing policy. We must discover what is on the minds of consumers. We must reach out to our communities and find out what people want; we must find new ways to help them understand the problems of our companies; we must find new ways to help them understand their options and make choices; we must find new ways to demonstrate that we care not only about the industry's problems but also about the customer's.

In the current customer climate suggests that we must reach out to our customers in new and different ways. We can no longer focus only on the so-called average customer (2.5 family members with a dog and station wagon). We must begin to look at the parts that make up the whole. Different constituencies feel different impacts. We must target constituencies and develop new cooperative relationships. We must consider effects on those with low income, seniors, minorities, and others. Hispanics represent the largest growing minority group. Their language problems alone create special barriers as they try to cope with the rising costs and a selection of choices.

Marketing research helps us better understand customers, but the changing times call for a more personalized approach, one that goes beyond the numbers and develops as many hands-on contacts as possible.

Advertising and public information are certainly tools to be used, but these are not two-way communication tools; they give information to customers but they do not solicit information. We must learn to communicate with our customers and share information with them. We must work with our customers. We must emphasize outreach. If customers and the industry do not understand each other, any pricing policy established will be in jeopardy.

In Search of Excellence (by T. J. Peters and R. W. Waterman, 1982) tells us that successful companies know their market, know their competition, and are not afraid to take risks. Let us find new ways to know our customers better, let us get to know public interest leaders, and let us not be afraid to take risks.

In his Principles of Marketing (1983), Philip Kotler says there are three kinds of companies: those that make things happen, those that watch things happen, and those that wonder what happened. Companies that make things happen are those that are partners. Those that watch what happened are those that look at the customer as an adversary. The successful company, according to Kotler, is the first, obviously. Do not forget that the business of business is to create and maintain a happy customer. The utility business is no different. It just seems that over the years we have forgotten a good share of that philosophy.

How does this relate to pricing policy? In my view, the most frequent communication we have with our customers is the monthly bill. We are great letter writers. Every month we send a letter to every one of our customers and communicate with them. The mail conveys our pricing policy. Most often the customer either does not understand the pricing policy or rejects it as being overly restrictive. What can we do? What kind of dynamic pricing policies can we pursue? For position, we can rely on the insight of the much consulted James C. Bonbright, who in the Preface to his landmark volume, Principles of Public Utility Rates (1961), stated:

Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control. But a system of rates that would be best designed to perform any one of these functions is unlikely also to be the best that could be designed to perform any of the others. Hence, to a substantial extent, sound rate-making policy is a policy of reasonable compromise among partly conflicting objectives.

Bonbright advocates rates designed to perform multiple functions arising from a sound rate-making policy of reasonable compromise among partly conflicting objectives. Restated,
a comprehensive or universal approach to rate theory results in rates that allow reasonable compromises, not at the expense of the utility or the regulator. The utility would expedite an informed response through an extensive, continuing process of customer information and education. The emphasis of the process would shift from time to time as needs change for the customers and for the utility. In any case, the customers would regain their sense of exercising control over their energy usage and costs; their choices in the form of pricing alternatives would exist once again.

Once in place, such rates would permit customers to respond in light of their own circumstances, not at the expense of the utility or the regulator. The utility would expedite an informed response through an extensive, continuing process of customer information and education. The emphasis of the process would shift from time to time as needs change for the customers and for the utility. In any case, the customers would regain their sense of exercising control over their energy usage and costs; their choices in the form of pricing alternatives would exist once again.

The opportunity for choice would be the availability of voluntary time-of-use rates for all classes of customers.

As reported by the Rand Corporation in their recent study:

Time-of-Day Electricity Rates in the United States (1983),

Time-of-Use Rate Structures Offer Benefits, But in Excess of the cost of installing the necessary metering equipment for most industrial and commercial electricity customers and a significant fraction of residential customers.

Multiple, metered periods priced appropriately would allow customers to tailor their purchases to their needs and financial constraints. The electric utility under the theory of a universal pricing approach would strive to make the most appropriate rate structures available over time. Although originally instituted for retarding the growth of peak demand, time-of-use rates offer much more versatility.

Another opportunity for offering choice in prices exists in tailoring rates by industry, community, or load factor.

Summary

The future demands flexibility and freedom in pricing, aided and abetted by forward-looking industry management and enlightened regulatory policies. We priced for many purposes in the past. We must price for customer and industry opportunities in the future. We must focus on creating and maintaining customers through determination and fulfillment of the needs identified by market research. Because rates cannot change every time customers wish for changes to meet their perceived customers, we must inform and work with customers to emphasize the features of universal rates designed to meet many needs on many occasions.

Times have changed. Are we going to make things happen, or will we, a few years from now, scratch our heads and wonder what has happened? Do not be afraid. Take the risk. Serving the needs of the customers is the way the industry got started. It was primarily responsible for its tremendous strength for more than a century. We can once again return the industry to a position of strength by recognizing that the customer is number one. We must strive to serve the customer's needs, not simplify the tasks for regulators or cost analysts in the preparation of a pricing policy.

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As reported by the Rand Corporation in their recent study:

Time-of-Day Electricity Rates in the United States (1983),

Time-of-Use Rate Structures Offer Benefits, But in Excess of the cost of installing the necessary metering equipment for most industrial and commercial electricity customers and a significant fraction of residential customers.

Multiple, metered periods priced appropriately would allow customers to tailor their purchases to their needs and financial constraints. The electric utility under the theory of a universal pricing approach would strive to make the most appropriate rate structures available over time. Although originally instituted for retarding the growth of peak demand, time-of-use rates offer much more versatility.

Another opportunity for offering choice in prices exists in tailoring rates by industry, community, or load factor.

Summary

The future demands flexibility and freedom in pricing, aided and abetted by forward-looking industry management and enlightened regulatory policies. We priced for many purposes in the past. We must price for customer and industry opportunities in the future. We must focus on creating and maintaining customers through determination and fulfillment of the needs identified by market research. Because rates cannot change every time customers wish for changes to meet their perceived customers, we must inform and work with customers to emphasize the features of universal rates designed to meet many needs on many occasions.

Times have changed. Are we going to make things happen, or will we, a few years from now, scratch our heads and wonder what has happened? Do not be afraid. Take the risk. Serving the needs of the customers is the way the industry got started. It was primarily responsible for its tremendous strength for more than a century. We can once again return the industry to a position of strength by recognizing that the customer is number one. We must strive to serve the customer's needs, not simplify the tasks for regulators or cost analysts in the preparation of a pricing policy.

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References


CHANGING PRICE POLICIES IN THE NATURAL GAS INDUSTRY

George R. Hall

Natural gas pricing is undergoing a change as profound as that wrought in 1964 by the Supreme Court’s Phillips decision. The supply response to the price incentives of the Natural Gas Policy Act of 1978, the conservation induced by the manypay increases in natural gas prices since 1973, and the intense interfuel competition for the boiler fuel load provided by residual fuel oil and coal are leading to fundamental changes in the process of natural gas price formation. Pricing changes are, in turn, engendering fundamental and long-lasting changes in the structure of markets and government regulation at the burner tip, city gate, and wellhead.

New legislation may or may not emerge from Congress. Regardless, the natural gas industry is going through a fundamental transformation. My assignment is to present an overview by briefly looking up and down the pipeline at some of the major changes taking place. Before beginning, however, we should be clear about the basic force producing the changes. This basic force is a shift from add-on pricing to net-back pricing.

As a result of the Phillips decision, a system of add-on price regulation came into being. Pricing began with a federally mandated producer price. To this was added the Federal Power Commission’s (Federal Energy Regulatory Commission’s) approved transportation rate. To the resulting city gate price was added the distribution margins approved by local
public utility commissions to obtain the gas price paid by
the final consumer.

As a result of legislative and economic changes in the
last five or six years, the process has changed to a net-back
system. We are all familiar with net-back pricing from oil
market participants. Price formation begins at the burner tip. Interfuel
competition results in a price that clears final demand mar-
ket. The distribution margin is subtracted to get the city
gate price. Subtracting this too reduces yields the
wellhead price.

This fundamental transformation in pricing from an add-on
to a net-back system is having profound effects on most
sectors of the natural gas industry. Let us look at a few,
starting at the burner tip.

**Burner-Tip Markets**

The need to clear the industrial and utility boiler
fuel market against the competition of unregulated and very
competitive residual fuel oil and coal distributors' requiring
natural gas distribution companies to be more market
oriented and to develop new pricing techniques. Equally
significant, it is forcing state public utility commissions
to develop new regulatory techniques for industrial and gas
sales.

Distribution companies in twenty-seven areas have been
given the requisite authority by their regulators to quote
flexible prices to industrial and, of industrial gas sales.

In twenty-four areas, some form of gas prices indexed to oil
prices has been permitted. Included among the utilities
with these pricing arrangements are industry giants such as
Pacific Gas and Electric, Southern California Gas Company,
People's Gas Light and Coke, Washington Gas Light, and Phila-
delphia Gas Works, 2

Indexed rates for industrial gas sales may be viewed as
the deregulation of retail gas prices to industrial custom-
ers. It would be equally valid to view this phenomenon as
a shift in public utility and industrial and industrial gas sales
from control of price to control of profits or contribution
to overhead. From whichever perspective, we are witnessing
a major transformation in industrial gas pricing and its
public control.

The new pricing flexibility is absolutely essential if
distribution companies are going to be effective competitors
against residual fuel oil and costs. Yet, there are obvious
ancillary difficulties for retail distributors and their
regulators. For example, premium customers and regulatory
commissions are going to worry about cross-subsidization.
Also, the industrial gas market is now becoming
characterized by considerable price and volume variability.
Yet, distributors have contracts with pipelines that bind them to long-term
stable commitments. Any business that "sells short" and
buys long" is in a very risky situation. In sum, the new
pricing flexibility and variability in prices and volumes
at the burner tip (necessary if gas distributors are to remain
viable competitors in industrial fuel markets), combined with
traditional city gate contracts and FERC tariffs mean that
the retail gas market has become much more risky.

Distribution margins are too thin to accept much uncer-
tainty. Twenty-five years ago, the gas cost component
accounted for 21 percent of the price paid by the final con-
sumer, and distribution costs were 46 percent of the final
bill. In 1981 the gas cost was 54 percent of the final bill
and the distribution margin was 21 percent. Regardless of
regulatory authorization to be flexible at the burner tip,
such margins cannot be achieved if city gate prices are out
of line with final demand realities.

An additional consideration is that in the past, on average,
gas distribution companies have had lower earnings-
to-book ratios than electric utilities or gas pipelines.
The combination of increased risk, thin margins, and skepticism
by the financial community creates a very sporty course for
distributors over the next few years.

**City Gate Markets**

Let us move up the pipeline to look at the city gate
markets and the distributor/pipeline relationship. Today,
pipelines are seen by many as the main cause of the current
economic difficulties in the natural gas industry. They
are particularly blamed for the current lack of congruence
between wellhead and burner-tip prices.

In the midst of tremendous diversity of opinion about
natural gas regulation, one of the few issues on which many
seem able to agree is that more pipeline accountability for
gas purchase decisions is required. The main differences
of opinion seem to be on how much more and how to achieve
it. "Pipeline accountability" in today's jargon seems to
be a polite euphemism for "more regulation." Thus, I think
that the current forces are likely to result in more government
intervention in pricing decisions at the pipeline level.
This increased pricing regulation for gas pipelines contrasts
with a trend toward more pricing freedom for other natural
gas entities.

If any new legislation comes out of Congress in 1984,
FERC jurisdiction over pipeline activities will likely be
significantly increased. Even if no new legislation emerges,
I think we can expect a much more active and possibly activist
stance by the FERC with respect to pipeline practices. New
initiatives such as those advocated by former chairman Butler
may come out of the commission. Even without these, we seem
to sure to see more FERC attention to pipeline practices. Pur-
chased gas adjustment filings used to be relatively routine; today, they have become highly contested. For the next few years they will continue to require large amounts of commission and industry resources.

Producers, distributors are becoming more active in regulatory matters involving pipelines. Their enlightened and galvanizing concern about maintaining the marketability of gas impels them to take on a broader range of pipeline regulatory issues and to pursue their interests more actively. Current issues involve minimum bills, cost allocation, and purchasing policies, but this agenda is certain to lengthen.

Producers have tended to concentrate on their legislative efforts to deregulate wellhead prices and have not been as active in pipeline and distribution regulation. This is bound to change. The gas market's proposal to limit gas cost pass-throughs puts pipeline regulation squarely before the producers. The logic of net-back pricing makes it inevitable that producers will be more involved in pipeline rate filings and distribution regulation issues.

The sum and substance of what is happening is that distributors, producers, and regulators are becoming much more involved in pipeline pricing issues. We can expect in the next few years, with or without new legislation, much more active pipeline pricing regulation, much more involvement by all segments of the industry, and now looks at many old pipeline pricing issues.

**Wellhead Markets**

Finally, we reach the field markets. The Phillips decision required wellhead price controls to be "reasonable levels." Since that time, maximum lawful prices for natural gas have been set, first by the FPC and later by Congress.

According to law, the prices established pursuant to the Natural Gas Act and Natural Gas Policy Act were ceiling prices. Any producer or pipeline was free to buy or sell gas at a price below the regulated price. However, the gas shortages in the 1960s and 1970s made the distinction between a ceiling and a stipulated price a meaningless legal nicety. Today, the NPGA's maximum lawful price is a fact as well as law, true ceilings. This is the new and revolutionary change in wellhead pricing that is taking place. With or without new legislation, wellhead prices have become the field price for gas is now and will be in the future a problem with which pipelines and producers must wrestle.

If market competition, rather than federal regulation, determines effective prices in the market, wellhead prices will have to be in congruence with burner-tip prices. This implies net-back prices at the wellhead, which in turn implies a considerable and significant change in the incidence of risk exposure. Ultimately, risk exposure will have to move up the pipeline to the field markets. Producers, unlike pipelines and distributors, will in time, and soon if President Reagan has his way, be unregulated. They are the only segment able to benefit from energy price increases, and it is an old doctrine in both economics and regulation that risk should follow rents. This shift in risk exposure is naturally being opposed by those who will have additional exposure.

Turning to the specifics of net-back pricing, the concept is becoming generally accepted. However, the algorithms or precise procedures for computing net-backs, what net-back values will be in the long run, and how to embody the net-back concept in specific contracts are complex questions. The usual view is that the reference burner-tip price must be the cost of alternate fuels in industrial and utility boiler fuel applications. Most net-back calculations today assume low-cost alternate fuel prices as the reference price. However, there are those inside and outside the industry who believe this will be another case of the myopia that has afflicted analyses of natural gas markets for three decades. They believe the long-run supply and demand equilibrium will be at a much higher price level.

After determining the price to use as a reference in the net-back calculation, one must determine the values to subtract to net out distribution and transportation costs. Different distribution margins for different classes of services as well as zoning and other pipeline rate complexities often complicate this computation.

Moreover, many changes in current rate practices are taking place. For example, there seems to be a move from Seaboard and Unified rates to modified fixed-variable rates. Such a change can have significant quantitative effects on net-back values. For example, as much as 50 cents per Mcf at the wellhead often depends on the assumption made about whether fixed-variable rates rather than Unified rates will apply.

Net-back prices must be embodied in contract terms. The era of fixed-price contracts has passed forever. Also, it is clear that contracts indexed to distillate or crude oil prices are inconsistent with market realities. Use of a residual fuel oil price index is possible. Either this or price renegotiation at frequent intervals is required to ensure harmony between burner tip and wellhead. Since frequent renegotiation seems most likely, this will mean a major change from the long-term price relationships that have prevailed in the past toward short-term relationships, the probable pattern in the future.

There is a way for pipelines to finesse, at least partially, the price determination problem, and some pipelines are doing so. Finessing requires a change in pipeline strategy. The traditional interstate pipeline product has offered a bundle of services. This bundle conventionally has included
purchasing, transportation, and sales of natural gas. Such a product-bundle strategy implies pipeline responsibility to anticipate and seek to meet the short-run and long-run needs of distribution customers. Pipelines performing this type of conventional middleman role are sometimes called "merchant" pipelines. In contrast, some pipelines seem to be developing a new business strategy that implies a different way of looking at what pipelines should do. The emphasis is on the transportation function and brokering of deals between producers and those serving the industrial end-use markets. The divergence which seems to be emerging among pipeline strategies has profound implications for the industry. Some pipelines are seeking to perform their traditional pricing and gas supply role. Others seek a new set of roles and missions which usually involve becoming contract carriers, at least in part. The NGA and NGPA are both premised on the status of pipelines as private carriers and wholesalers. Most of the legislative initiatives before Congress, however, would mandate at least some limited contract carriage responsibility for natural gas pipelines. Even without a legislative change in status, unbundling of pipeline services is happening on many pipeline systems. At least some seem well on the way to becoming contract carriers. Others are likely to find this new role attractive in the future. In time, the industry is likely to feature both contract carriers and merchant pipelines, which will mean major changes in pricing practice and industry structure.

On all pipelines, including merchant pipelines, transportation for others is becoming a more important part of the business. The Interstate Natural Gas Association of America (INGAA) reports that pipelines moved 6.4 Tcf of gas for others in 1982. In contrast, in 1976 they moved only 2.5 Tcf. Many transactions were pipeline to pipeline rather than producer to distributor or producer to end-user. It seems certain, however, that the forces unleashed by the current legislative debate, as well as the economic incentives created by supply abundance and underutilized industry capacity, will lead to more contract carriage on a voluntary or semivoluntary basis even without new legislation. This increase in the role of transportation service on the pipeline network will require distribution companies and producers to take on new roles heretofore exercised by pipelines. With or without legislation, we are going to see a major change in the roles and missions of pipelines and distribution companies as a result of the increasing role of transportation vis-a-vis sales for resale and increased competitiveness in end-use markets.

## Conclusion

The change from add-on pricing to net-back pricing is resulting in fundamental changes in natural gas pricing and its regulation at every level. This proposition holds whether or not new legislation emerges from Congress. I have only been able to touch on some of the more obvious structural and pricing changes taking place. I believe that my brief survey is sufficient, however, to demonstrate that the natural gas industry we see today and will know in the future is very different from the industry and pricing procedures we have known for thirty years. As Adam said to Eve: "Why dear, we live in a time of transition."

## Notes

TELECOMMUNICATIONS PRICING
IN A FICKLE REGULATORY ENVIRONMENT

James H. A’leman and Leland V. Schmidt

Over a period of years the FCC has put in place several decisions which have led to opening the telecommunications marketplace to competition. In taking these steps, the commission has recognized that its decisions will require changes in the price structure of exchange carriers. Moreover, these changes will have to be designed to move the telephone companies and their interexchange carriers to a position in which their prices reflect the underlying costs of their services.

The commission clearly recognized that subscriber access fixed costs could not be paid for by usage based prices, as they had been. In order to correct this situation, the commission instituted a program whereby these costs would be shifted back to subscribers as access charges on a per line basis, as economic efficiency demands. Shifted back is the correct term, for less than 40 years ago such costs were covered by subscriber access prices.

These FCC decisions imply quite a different market structure than in the past. There will be a redistribution of the total telecommunications bill from heavy toll users.

Note: The views expressed here are those of the authors and not necessarily those of GTE Service Corporation.

Telecommunications Pricing who have been paying multiples of their nontraffic sensitive costs in their telephone bill, to subscribers who do not make many long distance calls. Those with little long distance usage will see bills rise; those with heavy long distance usage will see bills fall.

Do not let this distinction between the heavy and light user fool you into thinking that these groups are synonymous with the rich and poor. GTE studies show that virtually all income groups (and age cohorts) contain heavy and light users of long distance services. One is only fooling himself if he believes the current system of service subsidies is designed primarily to help the poor.

With access charges the exchange carrier can price its services to avoid uneconomic bypass of the exchange system. However, the continuation of an artificial price structure gives the bypasser the incentive to build these more costly systems. (Incidentally, once the bypassers leave the telephone system, they have very little incentive in the future to return to the network, even if the price structure is corrected, since they have significant sunk costs in the bypass system.) This is a real resource loss to society. Moreover, as these users leave the exchange system, they will create a downward spiral of lost revenues. The exchange telephone plant remains and must be paid for by the remaining subscribers.

The move toward cost-based pricing, as predicted by the economists, gives us a net gain in economic efficiency. Various studies have estimated this gain at more than one billion dollars per year. Coupled with other pricing programs that GTE is implementing, we can further increase the gain in economic efficiency. In particular, local measured service or, as GTE calls it, usage sensitive service, can gain an additional $500 million or more per year. (See below.)

An important aspect of the correction of price structure which has not been recognized sufficiently is the gain in U.S. international competitiveness. The access charge implementation in the telecommunications price structure will ultimately reflect in decreases in the costs of goods sold, thus making our products more competitive abroad. They will not be carrying the burden of the toll subsidy. Moreover, this change in the price structure will have positive effects on the level of employment and rate of inflation. To those who wish to continue with the pricing status quo, we might ask: "How much employment would Detroit like to give up in order to obtain low exchange rates for those that do not need them?"

Legislatio

Let us examine what would happen under legislated regulation such as that proposed in the House of Representatives.
telecommunications bill passed in November 1983. We must 
add that it will have an intimidating effect on subsequent 
FCC decisions in this area. The cartoon by Mackley in 
Figure 1 encapsulates much of our thinking about the House bill. 
For the sake of a couple of dollars a month, the House would 
put in place legislation which has the potential to destroy 
the exchange carriers.

We submit that this legislation is deregulation. It 
is anticompetitive; it encourages uneconomic bypass. State 
governments in New York, Florida, and California are trying 
to reduce their communications cost by building their own 
network. Simultaneously, these same states are very concerned 
about doubling or tripling of the exchange rates. You cannot 
have it both ways.

Let us be very clear on this matter. The total telecommunica-
tions bill is not changing because of access charges; 
there will be a redistribution of this cost.

The legislation is going to retard technological effi-
ciency, particularly at the exchange level. Clearly, this 
legislation will be very burdensome administratively. One 
can get a picture of this by simply reading the bill. Recent-
ly, California passed a bill similar to the House bill which 
taxes the interexchange carriers in order to promote a Universi-
sal Service Fund to subsidize exchange telephone rates. Only 
one-third of the bill was concerned with the issue; the balance 
was concerned with administration of the "tax" and the fund.

In addition to the administrative difficulties, it is clearly 
recognized by the attorneys that there will be much 
adjudication over these so-called funds.

Generally higher consumer prices are ignored when ad-
dressing the access issue. The advocates of the legislation 
seem to think that there is a free lunch. There is none. 
Quite clearly, the cost of goods sold in this country is 
higher because businesses must pay a high cost for telecommu-
 nications. [We suspect that the indigent would be happier 
with lower food prices than lower telephone prices.] As 
lee Johnson has shown, under simplifying assumptions, at 
least 50 percent of these telephone prices are passed back 
to the consumer in the form of higher consumer goods prices. 
And this does not even consider the loss of output associated 
with these higher prices! Obviously, in addition to these 
higher domestic costs, the U.S. export position will continue 
to suffer because we are imposing additional costs on the 
 supply of our end-user goods.

To summarize this issue, the FCC subscriber access charge 
came into being to place cost on the cost-causative ratepayer. 
False price signals would not be given to potential competi-
tors, thereby avoiding inappropriate resource allocations. 
The long-run implications are that resources would be better 
utilized and the growth of the economy, employment, and
international trade would all be stimulated while reducing the rate of inflation.

In short, the legislation reimposes regulation by setting rates for a set of subsidized services. These services are subsidized through taxes on carriers that are administratively burdensome; many groups are seeking exemptions to the "tax." A natural consequence of these exemptions is a steady flow of individuals attempting to escape the surcharge through exemptions or other means.

We must be very clear in our understanding of what is occurring. Universal service was not in jeopardy; votes were in jeopardy. The FCC order contained provisions for high cost areas and for Lifeline service for the poor. The 30 percent of the population classified as poor was recognized, and mechanisms were in place to assure their continued participation in the telecommunications sector. What was in jeopardy were the votes from the 90 percent—who could easily afford the $2.00 charge.

Universal Service

We would like to clarify one issue which seems to cloud all the discussions regarding access charges. The telephone companies believe that the goal of universal service should be obtained. In particular, the telephone operating companies believe the best method is through subsidies targeted to the "needy." This, of course, implies that a means test must be met. We already have a welfare system in this country set up to administer this type of test. Moreover, we believe this subsidy should be publicly funded.

The targeted subsidy avoids the waste associated with service subsidy, which benefits the very rich and perhaps a few poor. The "means" test ensures that the subsidy is given to the most efficient fashion, that is, by those who need some support for basic telephone service. Since only 10 percent of households in this country could be so classified, the cost of supporting such a subsidy would it must, be one-tenth of what it is today! The service should be publicly funded because the benefits of universality of telephone service accrues to the entire community. Any narrowly funded program is subject to lack of public avoidance, which is one of the major problems with H.R. 4102.

On the face of it, the legislation purportedly offers a telephone company a way to keep low exchange prices in a competitive environment and a way to export costs to those calling outside its area. Why do companies not buy into that proposition? In their judgment it is a house of sand that will not stand up to the waves of competition and in the long run their business will be unable to achieve its basic goals, namely, universal, universal, quality service at reasonable rates.

In short, the legislation would reimpose regulation by setting in legislative concrete (1) a mandate for universal subsidized service; (2) administratively cumbersome mechanisms to generate subsidy revenue flows from heavy interexchange users by taxing them; and (3) mechanisms which allow many groups to avoid paying "taxes" by going around the local network system. The goal of universal service will not be well served by the legislation. Over time, its provisions will destroy the infrastructure of the established telecommunications system, which in the long run will cost those very consumers who are purportedly being protected.

Telecommunications Pricing

We now turn to a discussion of telecommunications pricing. There are three areas the telephone company must pursue, partially in view of the House bill and the FCC's latest actions. All are based on the cost-cause principle, which we feel is overriding both in terms of the way we conduct our business and in terms of improving economic efficiency for society as a whole (and these two are compatible). The three elements are local correction of the separations/settlements cost allocation mechanism, local measured service, and capital recovery.

Separations/Settlements

We will deal first with separations and settlements because the issue very much bears on the situation we are in today. The separations/settlements cost allocation mechanism was put in place more than fifty years ago and has been modified several times since, shifting more and more costs to the interstate side of the business. This arbitrary process has simply allowed nontraffic sensitive costs—which are, in fact, caused by subscribers subscribing to the telephone system—to be allocated to the interstate service. Interstate service prices have been based on these nontraffic sensitive costs plus the traffic sensitive costs.

While this may have made some sense when operating a fully integrated telephone system (although we have doubts that it was the proper procedure), it is no longer rational in the new environment of exchange companies and interexchange carriers. Basically, this cost allocation shifted exchange carrier costs to the interstate arena. Now that the distinction between interexchange carriers and exchange companies is clear, we feel that this arbitrary cost allocation should be eliminated. Not only does it cause an enormous administrative burden and cost, but also and more importantly it is totally inappropriate in today's environment. In fact,
what the early FCC decision was trying to achieve with its access charge decision was to correct these pricing distortions.

One has to consider the incentives the distortion creates. When the exchange company does not have to pay its full cost, its rates are indeed lower, but it does not have any incentive to maintain lower costs since costs can always be passed on to the interexchange carriers. In today’s environment, however, the exchange carrier sees its source of revenues being eroded by competing interexchange carriers which do not maintain this exchange cost support.

A very simple diagram may help to explain precisely what we mean (see Figure 2). If a terminal is connected to a central office switch, a message from the terminal is sent which has an address attached to it. The central office switch routes the call to another telephone instrument in the same exchange, a radio common carrier or mobile telephone service, a PBX, a computer, or even the point of presence of an interexchange carrier. The cost to the telephone company of that call is the same, other things being equal. The fact that it goes to a terminal or a point of presence of a carrier does not change the cost characteristics to the telephone company of that segment of the message. Therefore, we as a telephone company would like to have the price of that portion of the message be the same for each and every customer, irrespective of its destination. Since the separations process precludes this, one element of the telephone company’s cost-based-pricing policy—particularly in the face of the proposed legislation—is to remove this arbitrary cost allocation procedure. Moreover, under the current method of cost allocation, changes in the relative number of calls to these different entities change the cost allocation.

As an example of the effects, New York Telephone reports that with the House legislation its customers will pay $100 million in the first year to allow lower rates for subscribers in the south, principally Florida and California. Very simply, what the telephone companies want is control of their own costs. They do not want telephone companies to be become the cost increasers created by others, or depend on revenue sources earned by others. We do not want other companies’ costs controlling our rates or the costs that customers pay.

Indeed, this policy fits in nicely with the telephone company view of how many of these calls should be priced. It is an elementary principle of economics that fixed costs should be recovered by fixed charges and variable costs by variable charges. In a very meaningful way this improves economic efficiency and will not create undue distortions. It has been proven in rigorous ways, that this creates the greatest benefits for society. Moreover, in a competitive environment it is a virtual necessity to have costs based on cost causality. Certain elements of the telephone company’s costs which are fixed—the nontraffic sensitive portions of the subscriber loop discussed before—and others are variable, that is, the switching and transmission cost portion. At the exchange level, however, we have not been charging for these calls on a variable basis.

**Local Measured Service**

This brings us to our second fundamental move toward cost-based pricing in this competitive environment. We at GTE feel these variable costs are significant enough to warrant charging for them on a usage basis. We therefore are implementing a program called Usage Sensitive Service which will charge for each call going through the exchange system depending on its duration, distance, and time of day. Our aim is to price these services based on their costs. The paper by Edward Beauvais elsewhere in this volume elaborates on this pricing approach. We mention it here in order to outline how all the pricing policies make a coherent whole.

This change in the pricing structure would ameliorate any increase in the access charge which the FCC proposed. Once these two programs are in place, the telephone company is indifferent as to where the call goes. All the telephone company is concerned about is that its revenues increase with its costs.

This is in sharp contrast with the separations/settlements process. In that case, increases in local calls are detrimental to the company because their flow of toll revenue is reduced. More important, when other companies’ costs
increase, a company is affected by those higher costs. From the telephone companies' perspective, all of the calls which take place within the exchange should be covered by revenues generated within the exchange. Only then will prices truly reflect the cost of the supply of the service. Unfortunately, even in this context, we do not see the exchange telephone companies being deregulated in the near term. Our rates and our cost justifications will be very much subject to regulatory control.

Even before the events of November took place, there was no serious governmental policy decision—to deregulate the telecommunications sector of the economy in the last several years. No one has suggested that the telephone companies' exchange business be deregulated. Over the last two decades, however, public policy decisions have allowed competitive entry into a business formerly characterized as one of fully regulated monopoly services supplied in pursuit of public interest goals. For example, even at this time—fifteen years after the FCC Carterphone decision—it has not yet been decided by regulators which mechanisms are to be used to remove embedded CPE investment from the books of the telephone companies.

Capital Recovery

This brings us to the last element with which we are concerned. Since regulators are setting exchange telephone company prices and examining accounting practices, we have to ensure that these practices are compatible with the competitive situation. Some costs are easily identified; others are not. In particular, the cost of investment in plant and equipment has always been difficult to deal with in a regulatory context. We turn our attention to this issue, which is referred to as capital recovery.

In a competitive environment, the individual entrepreneur considers an investment, determines the cash flow associated with it, and evaluates it vis-à-vis today's and tomorrow's technological capability to produce the good or service. The decision to invest is based on an estimate of the revenue/cost streams which will accrue. The entrepreneur is only constrained by market forces. This revenue stream is to cover income taxes and the return on and recovery of capital after payment of all other costs. This is represented in Figure 3. With the passage of time, as newer and more productive assets are introduced by competitors, the net revenues available from the given asset typically will be reduced. The firm can observe that this revenue stream will or will not occur depending on the quality of the investment decision. It is not affected by the timing of book depreciation for financial reporting purposes.

The telephone company has to go through a similar process of evaluation, but it recovers the investment through a two-part process. First, regulation allows it to earn on the undepreciated invested capital. Second, over time it writes down the value of that invested capital through the depreciation process.

In the case of a regulated monopoly, the revenue requirements constraint is substituted for the market constraint. In the absence of competitors, the market constraint can be assumed to be much higher than the revenue requirements constraint, which is imposed specifically to prevent the monopoly carrier from earning a higher return than that allowed by the regulatory authority. This is represented in Figure 4.

With the introduction of competition, the regulated carrier finds itself subject to the revenue requirements constraint and the market constraint. If the timing of book depreciation is excessively delayed, the revenue requirements constraint prevents the carrier from recovering enough of its invested capital early in the life of the asset, and the market constraint intervenes later in the asset's life. With the introduction of competition in telecommunications, it becomes imperative that the timing of book depreciation permitted regulated carriers be sufficiently early in the
REGULATED MONOPOLY

$  

Net Revenues Available for Capital Related Costs  

Revenue Requirements Constraint  

Time  

Figure 4.

The life of assets to avoid conflict with the market constraint. It is important to note that adequacy of depreciation timing is far more important to the regulated carrier than it is to the unregulated firm.

The capital recovery process must be tied to the revenue stream that reflects the decline in the cost of the supply of the technology in a perfectly competitive market. If the depreciation base schedule does not match this decline in the economic value of the asset, then there is a distinct imbalance which would place the telephone companies at a disadvantage vis-à-vis competitive entrants. This is represented by the shaded area in Figure 5. In the initial year of the investment the firm cannot charge the market price due to the regulatory constraint. In a later period it is unable to obtain the necessary revenue to service the capital because the market constraint will not allow the price to be that high.

A clear example of this change in the cost of technology is seen in the dramatic decline in the price of computers and semiconductors in the microcomputer industry. Computer technology is not that much different from telephone switching and transmission technology. Regulators must recognize that even though the correct capital recovery procedure may require higher depreciation rates, the consumer benefits in the long run. Not to do so will lead to the deterioration of the company in the long run.

There has been a common misconception in the industry, however, that lower capital rates mean lower costs to the consumer. Although this is incorrect, it has led to a tendency on the part of regulators to prescribe an extended period for depreciating investments. Depreciation is not an arbitrary number; simply the asset value divided by the number of years of the useful life of the asset, but it depends intimately on the rate of change of technology as it affects the value of investments.

The question of capital recovery has always been addressed on the demand side: Can the consumer afford the service? But the key question is whether the telephone companies—who have the obligation to serve—can afford to supply the service to consumers. Without adequate capital recovery they cannot, and the first question becomes irrelevant.

If arbitrary cost allocations are eliminated, local measured service is adopted, and meaningful capital recovery programs are put in place, the industry has a chance for...
survival. Without any one of them, we face a crisis which the industry may not survive.

Conclusion

In summary, as a result of the legislation and its effect on subsequent FCC decisions, we are now filled with many negative thoughts about the inevitable consequences the pending legislation and decisions will have on the exchange carrier business over the next decade. Our thoughts are negative as well about the functioning of a federal and state governmental system that considers cross politics more important than rational long-term answers for an important aspect of our societal infrastructure. We also are not cheered that after several years of debate the outcome may be approaching, with increasing force, a bad answer.

Lest we cast too much gloom and doom, let us add that if the telephone companies are allowed to put into practice the pricing programs we have outlined, we have the possibility of viable exchange carriers. Let us hope these programs are not caught up in the cross political machinations that resulted in the current legislation and its aftermath.

Notes

1. See, for example, Lawrence Cole and Edward Beauvais, "The Economic Impact of Access Charges: Does Anyone's Ox Need to be Gored?" in Adjusting to Regulation, Pricing, and Marketing Realities (East Lansing Institute of Public Utilities, 1983); and Lawrence Cole, "Telephone Access Charges or Excessive Toll Charges?" Institute for Study of Regulation, Washington, D.C., forthcoming.

2. Cole and Beauvais, "Economic Impact."


the history of pricing within the industry, Abdo makes a convincing argument that the basic need for a utility's pricing policy should be used for within the electric utility industry must move out of the environment which in the 1970s created so many problems for the industry and the public. The key recognition in Abdo's paper is that if electric utilities are to have any chance to return to stable rates and stable financial performance, then pricing must reflect cost and market exposure. This relatively simple but essential understanding has been pushed to the background as electric utility management concentrated on finances in the short term rather than the function which electricity could perform in a developing energy market. Growth in plant or revenues alone, as has been amply demonstrated by the 1970s, is no longer the ultimate goal of the investor in the 1950s and early 1960s. The need to maintain financial solvency by means of construction work in progress, deferred taxes, and other accounting niceties, and some temporary relief at a price, but such accounting methodologies, if relied upon, will exacerbate not respond to the problems faced by electric utilities.

The basic lesson of Abdo's paper is that pricing cannot focus on short-term financial conditions while ignoring the fundamental changes in the market within which electricity is sold. This means that innovations on the industry's part must occur. The first is that the selling of electricity is not the sale of a kWh but of a service which will compete against services offered by others. These other vendors include not only gas distribution utilities and oil dealers but also conservation and alternative energy vendors. People are paying for electricity to sell; therefore, utilities must recognize that unless the service they present is the best option for a customer to meet that end, in a short time they will no longer have that option. The second recognition, which is intertwined with the first, is that pricing can no longer be preoccupied with internal financial problems but must be used to avoid future financial problems for minute utilities. Indiscriminate growth, as exemplified in the 1970s, is not the means of achieving stability in the electric industry. Rather, pricing, such as time-of-use rates, has been used to relieve costs and cost causality. Abdo suggests this use of pricing should be extended to establishing prices to meet end-user desires. Such a policy would produce several advantages. First, pricing to end-user desires based on market study, it is much more likely that existing plant might be more fully utilized. This marketing, if done well, should in fact serve as part of the planning function to reduce future costs by using existing plant (such as off-peak) rather than simply building more plant. Also, a knowledge of customer desires should assist in the development of alternatives to meet that demand.
coal, and electricity to satisfy customer needs. Achieving the ability to market at the end-use level by means of pricing, however, will be much more difficult to achieve in gas than in the electric industry because of the variety of participants in the pricing decision. The natural gas distribution utility, which is the market entity to end-users, is in the main a cost taker because it purchases natural gas as a commodity at a price determined by another set of companies. The need to create a mechanism to feed back the market prices which exist in the end-user market to the pipeline companies to the producers is the problem the industry faces today. As with electric utilities, unless the entire natural gas system is willing or able to determine and adapt to end-user needs and alternatives, hard times are in store. The present system composed of take-or-pay contracts, indefinite price escalators, or most-favored-nation clauses is incapable of allowing end-user needs to be accurately translated back to the producer level. Indeed, what must be created is a market in which each vendor recognizes the constraint on price placed on the buyer by the market. As Hall points out, what we see in the natural gas industry today is the effort of the participants to redefine their roles and missions within this new environment.

If competition has affected electric and natural gas pricing policy, it has invented a new world in telecommunications pricing. The one truism in this industry is that whatever existed before is unlikely to continue. Separation and settlements, depreciation methods, and local pricing are undergoing or will undergo fundamental changes in the near future. That is the thrust of the paper by Allman and Schmidt. Their lament is that regulators, including Congress, appear to be acting in a manner which would make the transition to a new pricing environment difficult, if not impossible.

No one would dispute that the telecommunications industry is in the throes of a major technological revolution. The problem this poses for the industry and its regulators is that the scale of the change, while obviously enormous, is unknown, and the speed with which it is occurring is overwhelming. We are being asked to change systems that have been in place for decades, and which have attained our goals very well, for systems whose effects are uncertain. Worse, there is a compelling feeling that the answers must be known now because the transition will occur whether it is planned or not. But the goals of the transition have not been agreed on yet.

The telecommunications industry during this transition may learn a lot from electric pricing principles developed in the 1970s and 1980s. Providing the opportunity for financial health to a utility, including cash flow considerations during a period of intense capital development, is a good part of the recent history of the electric industry. The pricing of various services based on cost-causative principles is available from the development of time-of-use electric rates. Cost-of-service considerations and rate design alternatives are also useful. But perhaps the best lesson that the telecommunications industry could learn from the electric industry is that attempts to achieve theoretical efficiencies based on cost-causative pricing is not a mechanical exercise. Pricing is a means to an end, and while different views of costs will suggest a range of prices, the choice of a specific price will depend on the circumstances in a particular service's market and the goals that one wishes to achieve. Thus, while Allman and Schmidt despair that certain pricing principles will not be stringently followed, the principles may not be followed because they do not attain the desired goals.

Pricing, according to all three of these papers, is more than the means to collect the revenue requirement. If used intelligently it can reduce future costs, produce efficiency gain, and satisfy end-user needs which are all to the benefit of the industries involved. The important question is what goals one wants to achieve through pricing. Abdo's paper discusses such goals. The other two papers reveal that the natural gas and telecommunications industries are in the process of defining (or arguing about) those goals which will translate into their pricing systems. We must first agree on what goals are to be achieved, and then a specific pricing system can be developed. We should not discuss pricing in a theoretical vacuum and lose sight of where we want to go.
Richard Abdoos recollection of the days when people's electricity bills were based on the number of outlets or lightbulbs in their homes was amusing. We all seem to recognize the foolishness of such an approach to pricing. Yet, let us recall that, until very recently, telephone companies were permitted and, indeed, would be expected to charge their customers based on the number of jacks or extension telephones in each house. Perhaps we will all be judged just as harshly in a few years when people review our views on pricing.

It appears to me that there is an underlying theme to this session and to the entire conference: How does one price a public utility service which is no longer characterized by a "natural monopoly", or how do regulators price the variety of services offered by a utility company when those services are in a competitive environment and when the degree of competition varies from service to service or among customer classes? This problem is most obvious in telecommunications, and it also exists in the electricity and natural gas areas. Simply put, the next decade will be characterized by greater own-price elasticity and cross-price elasticity than in the past.

Traditionally, regulators and utilities have designed prices in such a way as to load costs on business users and/or "discretionary" services in order to keep rates low for residential users. Now it is the business segment of customers which has seen its choices multiply; that is, it has become the most price-elastic customer group. Thus, if services are overpriced to the most competitive users, those users will exercise their consumer rights, leaving fixed costs to be paid by an ever-decreasing group of the less elastic customers.

Thus, the challenge for regulators is to help manage the transition from monopoly to competition. Regulators must weigh the public policy imperative of reasonable rates for small, relatively inelastic users with the economic realities of interservice competition. Fortunately, there is time to manage the transition. Competition is not like pregnancy, binary in nature. There exist degrees of competition and the speed with which competition infuses a marketplace can change over time. Therefore, there is time to move toward more cost-based rates and to avoid major disruptive effects on the broad base of relatively inelastic customers. Indeed, creative public utility pricing should enable the relatively inelastic customers to take advantage of the technological and other changes occurring in a given industry while protecting those customers from subsidizing the relatively elastic, more competitive aspects of the utility's services.

Turning now to the papers presented in this session, I find much to agree and disagree with. I agree with Abdoos that utility companies need to reach out to their customers. Price is not all, and utilities need to understand that they must behave like normal businesses in their customer relations, marketing, and so on. For example, telephone customers would just as soon remain with the local telephone company than engage in bypass if service is maintained at a high level and if there is a sense that the company is responsive to the customers' needs.

I think George Hall's paper was an excellent one which outlines many of the issues faced by the gas industry. I have been somewhat surprised by the lack of understanding of these issues often shown by gas distribution companies, but my sense is that those companies are becoming more aware and adjusting their policies appropriately.

Most of my disagreements center on the paper by Leland Schmidt and James Allenman. It seems to me they have fallen into the same logical trap formerly propounded by AT&T and now advocated by a number of local telephone companies. If one accepts the telephone companies' logic that fixed or nontraffic sensitive costs should not be priced on a usage basis, as has been argued in the FCC forum on interstate access charges, how can one accept the idea that the same type of fixed costs should be priced on a usage basis at the local exchange level? I understand that other papers will address this topic more fully. However, it seems to me that overpricing local usage will encourage bypass of local exchange services just as quickly as, if not faster than, overpricing toll service will encourage bypass of existing long distance networks.
Their discussion of the capital recovery problem faced by local telephone companies also raises some questions. Most competitive businesses, when faced with an inadequate depreciation reserve, write off unamortized investment against earnings. On the one hand, the local telephone companies urge us to adopt pricing techniques in response to a competitive environment. On the other hand, they argue that their prices must be increased to solve the capital recovery problem. I have yet to see an industry—other than those selling perfume, minks, diamonds, Porsches, or other luxury items—in which prices are raised in the face of competition. We must remember, too, in regard to the telephone companies’ capital recovery problem that the past depreciation practices were supported by the companies themselves, not just by regulators. Finally, they make mention of “crass politics” in discussing the redistribution of revenues in the telecommunications field. I must simply remind them that regulation does indeed deal with equity as well as efficiency issues. The practices of the past may be wrong for the future, but we cannot ignore the fact that people’s habits, life-style decisions, business decisions, and so on, were strongly influenced by past regulatory practices. “Crass politics,” should one wish to refer to it as such, demands that the public be treated sensibly and fairly during the transition period to the new pricing environment. Fundamental principles of fairness are at stake, and these must not be ignored. Else the entire process will be set back considerably and perhaps irrevocably.

In summary, I am tired of the approach put forth by Schmidt and Allman and often heard elsewhere, namely, regulated companies blaming regulators for the companies’ failure to recognize structural changes in their industries and then leaving regulators to solve the ensuing problems when companies offer logically inconsistent and/or politically insensitive approaches as solutions.

A common thread runs through these papers by Richard Abdoo, George Hall, and James Allman and Leland Schmidt: The government sector is failing in its responsibilities to utility ratepayers. In a world of rapidly changing technology and macroeconomic circumstances, the regulatory system is changing slowly. Moreover, regulators are too frequently resisting change rather than leading society to adjust to, and thereby efficiently exploit, new opportunities. Critics are focused on state and federal utility commissioners for slowness, on Congress for fickleness, and on state legislatures for inconsistencies. In thrust, government officials are seen as manifesting all the characteristics of defenders of the status quo rather than as rational economic policy makers in a rapidly changing economy.

One obvious response to these observations (a flip one) is: So, what’s new? A more relevant observation, however, is that there is something new in the complaints, namely, their intensity. Changes in utility regulation have not been brought about in an orderly way over the last decade or so, and now changes must come in a fast and perhaps disorderly way. The potential cost to the society of regulatory failure in the three industries under discussion is surely high and is surely rising fast.

I agree with Abdoo that there is a crisis of public confidence in the regulatory system, but I think I disagree with him, at least in emphasis, on the causes. I see this lack of confidence in the system arising not so much out
of the regulatory system itself but as a part of a much broader loss of confidence in the political and economic system. Yet, I see a much more serious problem for the regulatory system than he emphasized in the lack of confidence of knowledgeable observers of the system. It has not the same special sympathy for the system that poses a special danger to the current system of regulation.

The economic crisis of our time is, in my view, a lack of widespread understanding and respect for basic American economic institutions and the policy necessities which those institutions demand if they are to promote the rising standards of living which the public expects, and has a right to expect, from the technology available. In a macroeconomic context, the failure to implement certain policy necessities has resulted in unnecessarily slow growth, high unemployment, and inflation. At the utility level, the failure has resulted in unnecessarily high electric and gas rates and a somewhat retarded telecommunications system.

It is not, however, only the regulated utilities which are not being priced properly. In the unregulated markets for steel, autos, and agricultural and many other products, there is grossly improper pricing. As All men and Schmidt so elegantly emphasize, one consequence is an abundance of uncompetitive investment. Another is a failure to implement certain policy necessities which have resulted in unnecessarily slow growth, high unemployment, and inflation. At the utility level, the failure has resulted in unnecessarily high electric and gas rates and a somewhat retarded telecommunications system.

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regulators can ever become. Utilities and regulators should stick to their knitting and see that they do it well. If they fail, no one else can correct their mistakes.

While in principle I cannot disagree with Abbo's recommendation that electric utility competition will spread, as it is already doing despite the needs of their customers and to better market utility services, I must emphasize that should be a secondary part of a utility's efforts, except insofar as it furthers the principal responsibility as defined earlier. If it tends to deemphasize attention to the principal responsibilities, it should not be pursued.

Despite the generally pessimistic tone of my remarks, I believe several developments offer hope for improved pricing in all three industries under discussion here. Fruey conditions are changing fast. First, long term conditions in the electric power fields, and what logic could not do may be forced by compelling circumstances. Competition is increasingly important, and it will continue in all industries. The tide cannot be ordered back, even by a shortsighted Congress. Both Congress and regulators will be forced to confront this competition. I believe Ben Johnson said that "the prospect of imminent hanging clarifies the mind."

Competition is growing in many dimensions, but three are worth noting because they will force dramatic changes in long established utility pricing practices--changes which are overdue now.

First, the PURPA rights of cogenerators will bring into existence a group of competitors and potential competitors of electric utilities which will strongly encourage an economic rationalization of electric utility construction and pricing. Pricing mistakes by utilities will be noticeably more costly to utilities than they have been in the past.

Electric, gas, and telephone pricing will have to become much more responsive to demand, with some legislators' and regulators' responses to the transformation of telecommunication services and fears that such responses will impose substantial real losses on certain companies and most communication users, I find many elements of optimism in the telecommunication market. Since I do not own any securities of telecommunications firms, perhaps I can afford a slightly more philosophical view than can these authors. Competition is coming in most dimensions of telecommunications, and congressional and regulatory efforts to preserve an outdated pricing system will fail. Regulators may be slow to recognize the potential of competition, but they will respond in time. The consequence of serious pricing mistakes will be so obvious and so expensive to established firms and their captured regalayers that they cannot be long ignored.

Professor George Stigler is purported to have coined the phrase, "He who does not have monopoly power should not exercise monopoly power." Regulators, as difficult as it is for them to discover relevant facts through their elaborate

becomes more abundant. Hall has shown that this abundance of gas is forcing a profound change in the regulatory system for gas. Unless Congress reimposes controls so as to create another shortage, it is almost certainly inevitable that the utility's attempts to block it, to competition of "gas on gas": that is, pipelines will compete with pipelines, and pipelines will compete with distributors for the business of industrial customers. When competitive pressures make it necessary for pipelines to carry gas owned by others, as is increasingly the case, this "gas on gas" competition will bring gas producers and gas brokers into the market. Gas regulation will never be the same again.

Today's gas industry poses more clearly than any other the question: For what purpose do we regulate? Should it regulate the natural monopoly which the current technology dictates as a natural monopoly, or should we regulate so as to strengthen the natural monopoly so that certain dimensions of competition can be suppressed? I do not pretend to have a universal principle to answer this question, but I am convinced that wellhead deregulation of gas has produced circumstances wherein the current system of natural gas regulation cannot constructively limit "gas on gas" competition. The regulators would be wise to use their powers to facilitate it. Gas utilities and pipelines, even more than electric utilities, will find it expedient to define their services more precisely and unbundle their pricing. Products are not defined from Mount Sinai; they are defined by buyers and sellers. These utilities will also find the ability to sell emergency and standby services, services which come from large-scale generation, to small buyers and end-users.

Third, although I share the frustration of Allman and Schmidt and I fear that such responses will impose substantial real losses on certain companies and most communication users, I find many elements of optimism in the telecommunication market. Since I do not own any securities of telecommunications firms, perhaps I can afford a slightly more philosophical view than can these authors. Competition is coming in most dimensions of telecommunications, and congressional and regulatory efforts to preserve an outdated pricing system will fail. Regulators may be slow to recognize the potential of competition, but they will respond in time. The consequence of serious pricing mistakes will be so obvious and so expensive to established firms and their captured regulators that they cannot be long ignored.

Professor George Stigler is purported to have coined the phrase, "He who does not have monopoly power should not exercise monopoly power." Regulators, as difficult as it is for them to discover relevant facts through their elaborate
judicialized procedures, will soon discover that they do not control much monopoly power in the telecommunication industry any more.

In summary, I agree with Abdo that the credibility of utilities and regulators needs serious attention by both parties. I agree with Hall that the nation is at a critical point in its regulation of natural gas, and above all I agree with Alleman and Schmidt that careless, shortsighted legislation and/or regulation might do great damage to telecommunication users. But I would end where I began: Dealing with these problems and many more like them in the unregulated sector requires political and intellectual leadership of a high order. The three papers prepared by those men are examples of that leadership. They deserve wide dissemination and contemplation.

Part Two:
Adjusting to New Market Structures in Telecommunications
BYPASS: A COMPETITIVE ALTERNATIVE

Maurice Lamb

My presentation focuses on a timely issue that is being extensively discussed and debated by all those concerned with the new structure of the telecommunications industry. That issue is the cumulative effect of legislative proposals, changing patterns in regulation, technological change, and the competitive marketplace that has created a very powerful force accelerating the use of bypass facilities as competitive alternatives. I will review the various elements of bypass—economics, marketplace, dynamics, effect on the local telephone companies—and the role of the regulators in the bypass issue.

I am with the Central Services Organization, owned by the soon-to-be divested Bell Operating Companies (BOCs). I am not speaking for any one BOC. I am speaking about a problem that is of significant concern to all the BOCs.

Let me begin by defining bypass. In its most general meaning, it refers to the use of alternative communications facilities or services which go around or "bypass" exchange access or distribution facilities provided by the local telephone company. Bypass services can be voice or data, analog or digital, and switched or dedicated.

Marketplace interest in bypass was intensified in late 1981 as a result of the Satellite Business Systems (SBS) New York-to-San Francisco developmental trial. This venture was significant because several large suppliers joined to design a network to test the feasibility of various bypass technologies (satellite, microwave, digital radio, and coaxial cable). During this test, SBS provided satellite links.
between New York and San Francisco. The earth station in San Francisco was connected to a TWMET central microwave facility by Viscom’s coaxial cable and LLU ITS facilities; in New York local connection to end-users was provided by Manhattan Cable (a subsidiary of Time, Inc.). This trial clearly demonstrated to large customers (such as Control Data, Morgan Stanley, American International Real Estate, Merrill Lynch, Wells Fargo, and First Interstate Bank) the ability to communicate wideband digital data and video without the use of BOC facilities.

Since the completion of that trial in October 1981, the level of bypass activity has been intensifying. The pervasiveness of bypass today is not a fantasy; it is a well-documented reality. For example, this year Touche Ross completed bypass studies for Southern Bell and Pacific Telephone with the following results. In Southern Bell, out of the sample of 243 of the company’s largest local service-sector customers (in terms of MTS/WATS billings), "approximately one in four engaged in some form of bypass and approximately two out of three engage the bypass today or expect to do so within the next three years." At Pacific Bell, Touche Ross sampled 208 of that company’s largest customers: "24% bypass now in one form or another and an additional 23% plan to bypass in the next three years."

Various trade publications give examples of bypass and demonstrate the economics of bypass. Among them are: Data Cable News, Real Estate Telecommunications News, and Telephone Bypass News, published by Telestrategies; and Cable News, Satellite News, DBS News and Fiber Laser News, put out by Phillips Publishing. In addition, there have been several magazine and news articles, and hardly a month goes by when someone is not running a bypass seminar.

Examples of bypass exist in practically every segment of business and government today, including large financial institutions (Bank of America, Citicorp, Western Bancorp, American Express, Merrill Lynch); Fortune 500 industrial corporations with extensive national distribution (such as manufacturing networks (Westinghouse, Ford, General Electric, Boeing); government at the federal, state, and local level (GAFA, FAA, DOC, the states of Kansas and Virginia, the cities of Chicago, and education (DuKe, Brown, Stanford, Indianapolis Public Schools); transportation (Airline, Port Authority-NY, Southern Railway); lodging (Marriott, Grand and Tropicana Hotels); and aerospace (Hughes Aircraft, Martin Marietta).

Given the realities of bypass, let us talk about what is causing it. The basic driving force behind the recovery of nontraffic sensitive (NTS) costs on a usage sensitive basis from toll services. There no longer seems to be any supportable debate contesting the fact that NTS and WATS services have been priced above their economic costs and that the burden of these NTS costs is being disproportionately recovered from the high toll users. Unfortunately, this same pattern of usage sensitive recovery of NTS costs is still being proposed in the structure of access charges. Unfortunately, these proposals, which are getting very unfavorable reception in many circles, may be too little, too late.

Before going any farther, let me define two types of bypass: "economic" and "uneconomic." Economic bypass occurs whenever the costs of the bypass supplier are less than the telephone company’s costs for providing the same service facility. BOCs are not overly concerned about competing if their "economic" bypass costs can be used to price access services. In a fair and competitive environment, using their true costs, the BOCs will be able to compete. However, local telephone companies are concerned about uneconomic bypass. This occurs when the costs of the bypass supplier are higher than the telephone company’s costs--but the bypasses’s price to provide its selective customer access is lower than the telephone company’s tariff rate.

Uneconomic bypass in a monopoly environment has existed in the form of private line service for many years. Private line bypass is characterized by the high concentration of point-to-point transmission between individual customer locations or by point-to-distant community in the form of foreign exchange lines. Over the past fifteen years, separations procedures have dramatically increased the assignment of NTS costs to interstate toll, thereby accelerating use of private lines.

In many states, intrastate toll schedules have maintained a close parity with interstate toll schedules. This led to proportionate increases in intrastate MTS/WATS rates and increased the subsidy to NTS costs. This increase in cost assignment to MTS/WATS has brought about another type of uneconomic bypass--point-to-world carrier bypass. This is achieved by installing a direct connection from the customer’s premises to the interexchange carrier’s toll switch at a nearby point of presence (POP). Bypass of access entails bypass of both the transport from the carrier POP to the BOC serving central office and bypass of what is commonly referred to as "the last mile", that is, the telecommunications loop between the central office and the customer’s premises. This NTS loop comprises approximately 70 percent of the present price of access charges.

The imposition of this subsidy of NTS costs on the interexchange carrier is similar to the imposition of local taxes.
on manufacturers. When manufacturers could no longer compete with this cost burden, they moved away, and look what happened to our cities. Little of the city’s cost for services went away, but they lost some prime sources of revenue.

Since access costs amount to about 60 percent of AT&T Communications’ costs and about 50 percent of the BOCs’ costs, it is easy to understand why all carriers want to “move away” from such costs, and bypass permits them to do so. When they bypass, practically none of the BOC costs go away. If this root cause of bypass is not mitigated, we expect to see a lot of carrier bypass. A

Point-to-world carrier bypass also positions the inter-exchange carriers to provide directly intralAT&T services in competition with the BOCs and independents, and take a quick look at the facilities used for the point-to-world carrier bypass. Obviously, telephone company private line facilities could be used, but there are economic barriers to their use. The PCC requires the use of average fully distributed costs to determine private line rates. There are similar intrastate requirements. This averaging causes the price for private line service in high density wire centers, where the high usage originating (and terminating) toll users are located, to be set significantly above the economic costs for these wire centers. So, although the telephone company’s costs are lower than the bypasser’s costs in these wire centers, its tariff, based on average costs, is higher. Therefore, despite the economic absurdity, telco facilities are bypassed by a higher cost supplier. This is not competition, it is opportunism.

Prices based on average costs and cross-subsidies of various services may have been justified in a monopoly environment. However, they are obviously inappropriate in today’s market environment where the BOCs must compete with suppliers who are under moderate to no regulation, and who employ market-based pricing reflecting their relevant costs. With this pricing flexibility and relative freedom from regulation, these bypass suppliers can choose to provide only special services to niche markets in high density urban centers, office complexes, or industrial parks, and they do it without the public interest responsibility to provide access in high cost areas at the same price levels or without any other franchise responsibility to maintain service to all under any condition.

Another market characteristic relevant to bypass is the high degree of concentration of BOC customers and revenues. Today, close to 70 percent of all telephone company BTS/WATS revenues is derived from approximately 5 percent of the total wire centers; these are the high originating toll or "hot" wire centers. Furthermore, approximately 2 percent of all telephone company business customer locations generates about 55 percent of total BOC business BTS and WATS revenues. These customers are readily identifiable in the marketplace and can be readily provided with alternative serving arrangements.

These revenue and customer concentrations attract investment in a variety of access and distribution technologies. Niche competition is stimulated by some new technologies which require short lead times and are less capital intensive. The array of technologies available is indeed formidable. One is microwave radio. High frequency digital microwave (such as GE’s Gemlink) has perhaps the greatest potential of all bypass technologies, providing many advantages such as limited right of way problems, rapid deployment, and high speed data and wideband capability. There is also lower frequency microwave in the form of Digital Termination Systems (DTS) for which a diversity of applicants—such as IX carriers, value-added carriers, CATV companies, and telephone companies—see a market potential.

Among other technologies are the following. (1) FM sideband. FM stations can utilize a portion of their assigned frequency to provide services such as paging, electronic mail, and facsimile. Several firms including IBM have been researching the use of this technology in various data transmission formats. (2) Coaxial cable. This medium, with its large bandwidth and two-way interactive capability, is well suited for high speed data transmission and local area network applications. (3) Optical fiber. Using optical fiber, today’s light pulses are capable of transmitting extremely high speed digital signals up to seventy miles without amplification. This technology is being strategically utilized by interexchange carriers. (4) Infrared. A number of systems using user-based infrared light technology are on the market (such as Datapoint’s Lightlink) and under development. This atmospheric medium is used for transmission of data between buildings in line of sight proximity. It employs relatively basic optical technology which can be rapidly deployed. (5) Satellite. By 1986 it is estimated that about thirty satellites will be in orbit employing more than 600 transponders.

Given the continued imposition of the NTS burden on access and the relative costs associated with these technologies are not prohibitive. Thus, not only is the technology for bypass available, but also we have many new competitors using or planning to use these technologies. An example is cable television. Operators have the potential to go from home entertainment providers to communications companies. They have the capability to offer a full range of residential interactive home information services, and there is even a potential for offering plain old telephone service (POTS). End-user direct access capability to interexchange carriers has been clearly demonstrated in the COX/MCI "Cablephone" trial. Operators can provide data, video, and voice services
through dedicated institutional networks or "I NETS" such as those currently deployed by large operators (Warner Amex, COX, and Manhattan Cable).

We also have real estate telecommunications brokers who enhance the value of their properties by providing for shared use of telecommunications under the teleport/telebuilding concept. They plan to provide multi-technology access to a wide range of office automation, switching, and transport services. All based on the economies of scale of shared access. Expected benefits to the promoters are higher rental fees and higher FTT rates. There are several teleport projects in progress now. It has been estimated that by 1988, 75 percent of all major metropolitan areas will be served by a teleport. The telebuilding market is being cultivated by large entrants such as Olympia and York (Olympianet), SBS Railcom (a subsidiary of SBS), Hartz Mountain Industries, and United Technologies.

Of course, no look at competition would be complete without considering the interchange carriers. They have the strongest bypass potential with multiple PDP strategically located within major business centers such as MCI and GTE already offering direct access services (MCN Network Service) and GTE "Direct Sprint" from their PDP to the customer's premises. Also, given AT&T Communications' substantial market presence, this type of bypass can be expected to grow.

A major AT&T service offering is a continued requirement for high levels of NTS contribution from AT&T Communications.

In addition to these competitive alternatives in the marketplace, many regulatory and legislative activity is also fueling the growth of bypass. Considering state regulatory reluctance to change the structure and level of NTS rates, it is also not surprising that in the proposed customer access line charges and carrier access tariffs are increasing rapidly. As more companies come to realize the economics of bypass, the marketplace could not be getting stronger signals or a stronger incentive to bypass.

Bypass presents a multifaceted dilemma for all those involved in telecommunications: the regulators, legislators, the courts, carriers, competitors, and, of course, our customers. The alert needs to be rung. The unsolved problem of toll subsidy of NTS costs, which is the fuel—the "dry grass"—of bypass, has been known for years, and we knew that under the separations procedures in place it would get worse.

Today, all of us need to recognize the tyranny of the marketplace in this structured competitive environment. Where competitive alternatives are available, it is no longer feasible to continue to manipulate the pricing of services to
achieve the level of past subsidies. The competitive marketplace will not permit it to happen. Market realities must be recognized. We cannot act as if there is a monopoly for some services when the market environment is indeed competitive.

In this mixed environment local telephone companies and regulators share common goals. At stake is the viability of widespread, affordable universal service and the viability of the telephone companies, Bell and independent, who are the only ones regulators can count on to provide the ubiquity required for universal telecommunications service.

We have accepted the competitive environment declared to be in the public interest. We are willing and obligated to play that new game. However, we are severely disadvantaged—indeed, endangered—in trying to play the new game under the old monopoly rules which mandate the continued level of subsidy of local services. In this new game, where alternative suppliers can be found, market and cost-based pricing of services is imperative to the survival of universal service and the telephone companies that can provide it.

The filed access charges and the customer access line charges only begin to mitigate the cause of bypass. The cost/price disparity problems and the competitive penalties they impose must be eliminated. I recognize the political realities of these difficult issues and the hazards in getting public understanding and then acceptance of solutions that are in the long-term interests of most involved parties. However, there is no economic or public need to continue to subsidize every access line to preserve universal service. Lifeline service will provide a safety net for the marginal customer. The universal service fund will help support high cost areas.

Time is running out on the bypass issue. There is no turning back to a total monopoly environment. Positive and constructive action must be taken, and it must be taken soon.

A FRAMEWORK FOR EVALUATING THE THREAT OF BYPASS IN STATE REGULATORY PROCEEDINGS

David Brevitz

The subject of bypass has been put at the center of the national debate on telecommunications policy. In general, bypass means the use of facilities which go around the local exchanges of the public switched network. More specifically, the professed concern of the telephone companies (AT&T, the BOCs, and some independent telcos) is "uneconomic bypass." This has been defined as occurring "when a competitor with higher costs than a local telephone company is able to price its services to customers at a price lower than the local telephone company."1

The threat of bypass has been coupled with an economic philosophy regarding local exchange costs to form the basis for flat end-user charges at the federal level. The same approach has been used by many telephone companies in an attempt to persuade state regulators that state end-user charges are necessary. That approach requires close scrutiny by state regulators. In return for something of uncertain benefit, obtainability, or necessity—avoidance of bypass—flat end-user charges are to be imposed which are of certain detriment to local ratepayers. Analysis by the Kansas Corporation Commission staff of bypass as an imperative requiring state

Note: The views expressed here are those of the author and do not necessarily represent those of the Kansas Corporation Commission.
end-user charges has shown that bypass does not prove a need for such radical rate structure in Kansas. I believe similar analysis in other states will produce similar results in many, if not all.

Subsidy

The claims on the bypass issue begin with an economic philosophy which holds that all local loop costs are attributable to one service—"access"—and hence should be charged to each customer who gains access. Each customer under that philosophy should pay the full capital and operating costs of "his" or "her" loop. Therefore, those loop costs which are allocated to interstate toll are to be recovered with a flat rate charge to each local ratepayer. In this fashion, interstate toll service will be "reap" of the "uneconomic burden" placed on it by the current usage based recovery of loop toll no longer (after the transition period contemplated in the FCC access charge orders) "subsidize" local rates.

Unfortunately, the solution to NTS plant cost allocation and recovery is not that simple. Recovering the interstate share of NTS costs on a flat rate basis is a complete reversal of the existing method of usage based recovery. The FCC went from one end of the spectrum (usage based recovery of NTS costs) to the other (flat end-user charges) primarily in response to AT&T's assertion that such a swing was necessary to avoid bypass and resultant economic harm to ratepayers. The more fundamental reason for AT&T's assertion was its desire to shed its share of NTS costs and gain greater pricing flexibility and profit margins. There was no analysis of how much cost actually had to be placed on end-users in order to avoid bypass.

The Joint Board separation proceeding in Docket 80-286, AT&T's position was characterized by the slogan "SSF" in '82. "SSF to zero" was even more desirable from the company standpoint. This was a position advocated under the name "end-user charge" in the access charge proceeding (Docket 78-72).

The Joint Board decided on the buffered gross assignment plan for cost allocation. The transition to a 25 percent gross allocation of NTS costs to interstate was nowhere near the SLU measure, or less, which the interchange carriers proposed. But the Joint Board recommended it applied to NTS costs was effectively mooted by the FCC's Third Report and Order in Docket 78-72. AT&T and the other interchange carriers did not get all they wanted in the Joint Board proceeding, but they were able to make up the difference by prevailing upon the FCC to mandate flat end-user charges for the interstate share of NTS costs. AT&T and the interexchange carriers "bypassed" the Joint Board.

Evaluating the Threat of Bypass

It is eminently reasonable that interexchange carriers pay to use local facilities, as was originally contemplated in the FCC access charge proceeding until 1982, when flat end-user charges were proposed. Local exchange facilities are built to serve at least two services—local and toll. The network is built this way since it costs less to provide service using plant jointly, rather than using separate local exchange networks for each service. Local exchange facilities are assets owned by the local telephone companies and are of value to interexchange carriers since calls cannot be originated or terminated without using those facilities.

That proposition should be intuitively apparent. If local telephone companies were willing and able to close off their facilities to interexchange carriers until and unless they were compensated for use of the facilities, payment from interexchange carriers to local exchange companies would quickly materialize. To use a concrete example, one can be certain that Cox Cable has obtained something of value from MCI for the use of Cox's facilities in the Omaha experiment.

Furthermore, toll and special services impose costly demands on local exchanges. Facilities which are jointly used by multiple services must be engineered to meet the technical requirements of the service which imposes the most stringent demands. For this reason, the local exchange network has changed over many years to accommodate toll and special service services. Further changes in the local exchange network are currently envisioned and in progress to put in place an integrated services digital network.

There is no perfect solution to the allocation and recovery of NTS costs using traditional industry defining concepts, even in theory. Allocation and recovery of joint costs between different goods or services occur in industries other than the telephone industry. A cost is considered joint when it is incurred in a single productive process that results in the production of two or more products (none of which are considered byproducts). Two things make the telephone industry relatively unique in the area of joint cost recovery. First, the industry has a high proportion of joint as compared to total costs. Second, the industry operates in markets characterized by varying degrees of competition. The combination of no single and unambiguously acceptable theory of cost allocation, a large number of dollars at stake, and long distance companies with an incentive to shed costs, but passing them to customers of services which are price-inelastic, is responsible for a large part of the controversy in the industry today. The level of compensation required from interexchange carriers depends on these factors. But difficulty in allocation is no reason to give long distance companies a free ride on local facilities by not charging them for a portion of local NTS costs.
Allocation of joint costs to long distance services and recovery of those costs in toll rates do not constitute a "subsidy" to local service. It is reasonable to expect an entity to pay something for facilities it uses in the course of conducting its business. Rather than "subsidy" the proper term is reimbursement or payment. The ubiquitous local exchange network is valuable to long distance companies as well as to local telephone companies.

Labeling a payment a subsidy implies an objective cost standard. The basis of the common claim that local service is subsidized rests on the conclusion that all NTS costs should be directly assigned to local ratepayers. This begs the question. The real question is how joint costs are to be allocated to and recovered from separate services. The physical fact that a local loop is directly attributable to a customer and is geographically within the local exchange does not relieve long distance carriers of an obligation to bear some of the costs of those facilities, which those carriers also use. There is no objective method for NTS cost allocation. Therefore, no objective cost standard exists on which to base a claim of "subsidy." Following the Smith v. Illinois decision, NTS costs have been allocated by agreement of the parties involved. Since AT&T could not obtain agreement for changes within the Joint Board processing in Docket 80-286, cries of "subsidy" were heard, and the matter was instead resolved for the time being by the FCC in its access charge orders in Docket 78-72.

In competitive markets, the joint costs associated with different goods and services would be allocated and recovered according to the demand elasticities of the end products. In other words, the product with the highest demand elasticity would bear relatively little of the joint costs, while the less demand-elastic products would bear relatively more.

Although it is not being presented that way, in effect the same principle is being applied in the allocation and recovery of the joint costs of the telephone industry. The ultimate impact of the FCC access charge decisions in Docket 78-72 is to allow the marketplace to implement that principle. Specifically, the long distance services, which are more price-elastic than local service, will bear a declining share of local exchange costs. Under this scenario, long distance services will ultimately bear none of the network's NTS costs (except for the High Cost Fund and coin phones). Local service, which is a price-inelastic product, will bear the major share of joint costs, while long distance services under the guise of competition shed those costs. This outcome is known as Ramsey pricing and it has been advocated by the Bell System.

Valid social goals will be damaged by allowing inter-exchange carriers to push joint costs to monopoly services. By not charging long distance companies for the use of local facilities, local ratepayers will see their rates jump dramatically due to flat end-user charges. Some customers will have few or no long distance calls. Some of the more economically disadvantaged telephone customers will drop off the network due to that jump in price. A most important aspect of the national telephone network today is its ubiquity. In a practical sense, universal service has been achieved. But if current trends continue, universal service will be sacrificed for the benefit of the long distance companies.

The above statements are not meant to imply that no changes were required in methods for allocating joint costs and recovering them through rates. They are intended to indicate that the FCC's actions were more drastic than necessary. The amount of NTS costs allocated to interstate rates has been reduced by previous actions. SPF has been frozen, customer premises equipment is being phased out of the interstate ratebase, and inside wiring is being reimbursed rather than capitalized. The FCC takes the result as positive in large part being charged to the cost-causeative customer). Consideration is being given to deregulation of the provision of new wire with concomitant removal of associated expenses from interstate rates. Furthermore, the Joint Board has recommended to the FCC a transition toward a 25 percent gross allocator.

Bypass

The FCC's access charge orders are based in part on a desire to remove the incentive for large users to engage in "uneconomic bypass."10 Attached as Appendix F to the Third Report and Order in 76-72 is a "Status Report on Near-Term Local Bypass Developments." The information contained in it shows the complexity of the bypass issue, which is multifaceted and has not been well defined.12 The Kansas Corporation Commission was presented with a study of bypass in Kansas in its hearing on intrastate access charge methods. The study, conducted for SWB, provides a discussion of bypass technologies and information derived from surveys and interviews of large customers. This study indicated that 18 percent of the customers surveyed expressed willingness to bypass telephone company facilities for no savings at all. Moreover, the factors involved in a bypass decision are by no means only cost considerations. Survey results indicate (with more than one response allowed) that "lower cost" was cited 103 times, while "better service" was cited 87 times and was second only to cost in terms of frequency. A large user might bypass for many reasons other than price. Customers with high speed data transmission needs may find that owning or leasing such facilities better meets their requirements than does use of telephone company
facilities. Those users may want to avoid delays in getting new services implemented or facilities in place. They may wish to internalize the servicing and reconfiguring of their communication system. They may wish to tailor the system more closely to their needs and reasons for having facilities, to make it less complex, and excessive reliance on price as a "solution" to bypass is a misleadingly simplistic response.

Bypass affects the utilization of telephone company facilities. Those who advance the threat of bypass is justifying end-user access charges state that bypass will result in the widespread abandonment of facilities, whose cost would be spread to remaining ratepayers. Further distinctions need to be made. Some company facilities would be abandoned if a customer bypasses—primarily NTS facilities and remaining investment which was utilized by the customer is traffic sensitive plant. This plant then becomes available to meet the growth demands of other customers. So all plant previously used by a bypassed customer is not used again. Any stranded NTS costs specific to the bypasser can assume less significance when compared to savings from investment which does not have to be made since the bypasser's departure from the network frees existing capacity for use to meet growth. Remaining ratepayers may benefit in this instance since they would be served by existing facilities and not have to pay some portion of investment costs of new facilities to meet growth.

Stranded investment from a large Centrex customer abandoning that service is a different issue. That departure is encouraged, not discouraged, by the FCC's access charge ruling. Such stranded investment may be "less" reusable and more harmful to local ratepayers than bypass of other facilities, if spread to remaining ratepayers.

In fact, state commissions have options for spreading the costs of abandoned facilities among remaining ratepayers. To the extent bypass occurs, a "death spiral" does not have to be initiated. These options probably will not be advocated by the telephone companies, but they require consideration. First, traffic sensitive facilities stranded if a large customer bypasses the network can be removed from the rate base. Recovery of associated costs can then be deferred until growth demands by other customers again make the facilities "used and useful." Second, any customer-specific facilities stranded if a customer bypasses the system can be quantified and assessed back to the customer. The some sort of surcharge on the network services the bypasser does keep. A bypasser will still have some access lines to the nationwide network. The charges for those lines can be adjusted to reflect the customer-specific costs left behind by the customer's bypass. Termination charges can be designed for facilities needed by customers for prospective services. These allow more equitable treatment of remaining ratepayers and break the "death spiral" before it starts. This is especially so if the bypass is primarily of the telephone company's private line services.

If a state commission is presented with a survey of large users to support the "threat" of bypass and rate restructuring several points need to be addressed in the study for it to have any validity. These points were not explored in the study presented to the Kansas Corporation Commission. First, there was no analysis of the potential effect of the FCC's decision on the customers surveyed. In other words, there was no estimation of the size of interstate rate reductions to private "bypassers" due to access charges and a study of whether those rate reductions or future interstate rate reductions are necessary to keep customers from bypassing according to the answers to other questions in the survey. In fact, billed revenues of the large customers surveyed were not separated as between interstate and intrastate long distance services to permit this analysis. Second, and relatedly, no study was made of the effects state tariffs may have on a potential bypasser with a national or regional scope of business. The importance of state access charge tariffs to a large customer whose decisions are based on national criteria was not assessed. It is possible if not likely that the interstate treatment of access costs would offer those customers a sizable price reduction.

Third, there was no quantification presented in the study as to the significance of MTS/WATS charges relative to the potential bypasser's total bill. The customer may make relatively heavy use of private line service, which currently bear no allocated NTS costs other than direct costs. Therefore, any potential savings from reduced MTS/WATS rates could be a small part of the customer's total bill. The customer may actually be indicating a preference to bypass the telephone company's "bypass" service—private line.

Fourth, there was no quantification of the incentive to bypass which some customers will feel as a result of the FCC access charge orders in Docket 78-72. Those customers withCentrex service may have added impetus to bypass due to the imposition of end-user charges on a per-line basis to Centrex customers.

Fifth, the bypass examples cited in the study are not necessarily in place, final, or permanent. All the examples cannot be construed as ongoing, established business ventures. Not all will be profitable in the long run. It should be remembered that some of those touting bypass are trying to raise capital and gain customers. Their "support" of the bypass threat can hardly be considered disinterested.

Sixth, there is no separation of the bypass examples between "economic" and "uneconomic" bypass. Presumably, all examples are claimed to be "uneconomic," but there is no quantification of that claim under any cost standard.
Conclusion

These observations are not meant to deny that bypass is occurring. They are intended to put claims regarding the threat of bypass in perspective. Populations surrounding bypass are broadcast and general. The "cure" applied in the FCC's access charge order bears a more direct relationship to the desires of the interchange carriers than to the elimination of "uneconomic bypass."

Diversity in the supply of telecommunications equipment and services is assured by new entrants to the industry and by networks. However, shifting the prominence of network joint costs to monopoly raters is designed to facilitate the competitive pricing of services provided to larger, specialized users by telephone companies. State regulators should be wary of allowing costs to be recovered residually from local ratepayers when telephone companies compete in other services. To protect retail competition, it is essential for regulators to subsidize the services where the telephone companies feel competition is emerging.

Local exchange companies want to be the vendor of choice for new telecommunications services. They seek to retain customers and market share in the expanding market for telecommunications services. This is a perfectly rational and understandable goal from the standpoint of the telephone companies.

If bypass occurs, the affected telephone company loses a piece of the growth in the telecommunications market for some indeterminate period. Bypass in many cases could consist of customers deciding to subscribe to other services with their own networks rather than relying on the telephone company. While the telephone company would then, to some extent, be relieved of the expenses of specialized facilities, it would not also have growth in revenues from that source. This is probably the real concern of the telephone companies, yet the argument is coached in terms of maintaining existing revenue sources rather than preserving opportunities to participate in future growth markets. This is misleading.

One bypass example often cited is StarTel in Las Vegas, but that example proves a point other than intended by those citing it. The local telephone company turned down an opportunity to share in the revenues with the bypassers. It therefore lost an opportunity to participate in future growth. That local telephone company learned from the experience and will attempt to become a partner in similar situations in the future, rather than lose all the revenues.

Modernization of facilities is an integral part of telephone company strategy to avoid bypass. New facilities provide the ability to offer new services. Large customers with sophisticated service needs are at this time the primary source of demand for the newer services. Modernization of facilities may be a more important element than price in telephone company strategic planning to avoid bypass.

With greater specificity in the accounting for costs of services is even more essential now with the proliferation of services. Local ratepayers will bear the costs of telephone company competitive posture without better accounting and more attention to cost of service. State regulators need to be able to establish parameters so that costs will not be shifted to local ratepayers when competition is encountered in another market.

One method is the stand-alone test. A group of customers should pay no more for their service when provided using joint facilities than would be paid if their service were provided separately using stand-alone facilities. The test can also be applied to the services used by a potential bypasser. For example, the amount of depreciation expenses for which local ratepayers are purportedly responsible under existing allocation methods, plus accelerated depreciation rates and practices may exceed the depreciation expense which local exchange ratepayers would pay for stand-alone facilities constructed for basic local service. Any "excess" depreciation expense could be allocated to the cost-causative service or to company shareholders rather than to local exchange ratepayers. At a minimum, some sharing of these costs is acceptable, but this is not the result under residual rate-making concepts.

Local ratepayers should not be residually responsible for telephone company costs. This does not give the telephone company the proper incentives as to when and where to upgrade. The proper emphasis is therefore not necessarily placed on market research and marketing strategy. Telephone company managers and stockholders must bear the real risks of their decisions and balance those risks against the potential earnings in new markets. There are at least two inconsistencies between the telephone company's position on bypass and access charges and its positions on other issues. First, it is ironic that at the federal level it is claimed to violate principles of economic efficiency to recover MTS costs as part of usage-based rates, while at the state level the answer to problems created by increased flat rate charges (both local and toll access) is usage-based recovery of MTS costs—commonly known as local measured service.

Second, the telephone companies express great concern about the amount of cost paid by large users (potential bypassers) yet seek to increase total revenue requirements by accelerated depreciation methods and rates. In its broadest application, the term "cost causer/cost payer" is being ignored. Sophisticated users are driving an important share.
of company investment. Local ratepayers are being asked to bear increased cost for depreciation to finance investment for users of specialized services. Risks of market entry for such services are being assessed to monopoly ratepayers.

State regulators should be skeptical of bypass as a rationale for radial rate restructure. The implied cost standard is defective. Telephone company efforts to pass costs to less price-elastic markets are not unique or novel. They are a response to latent or actual competition in certain markets. They have been seen before in the vertical services and private line markets. State regulators are confronted with the question of how much latitude for price discrimination between competitive and monopoly markets the telephone companies should be given. Passing all NTS costs to local ratepayers in the form of end-user charges gives complete discretion to the companies and impedes the ability of state regulators to maintain universal service.

The nexus between intrastate bypass and intrastate end-user charges has not been established. There is reason to believe that bypass is a phenomenon affecting the private line market for high speed data transmission, but that would primarily be caused by direct cost levels, service availability, and customer service. The connection between bypass and NTS/WATS services is less clear. The bypass argument is symbolic of telephone company opportunism in seeking to recover its costs from its most stable revenue source—monopoly local ratepayers.

Notes
2. Reference to the "FCC access charge orders" should be read to mean both the Third Report and Order in Docket 78-72 and the Memorandum Opinion and Order in Docket 75-72, adopted July 27, 1983.
3. It should first be noted that there is doubt whether access line costs, classified historically as NTS, are as completely NTS as the conventional wisdom dictates. Local loops are part of the integrated switched telecommunications network and are affected by traffic considerations. The NTS label (and its connotation of fixity) is possibly being applied to more loop costs than is justifiable in the context of long-run economic costs. For a full discussion of this point see John Wilson, "Telephone Access Costs and Rates," Public Utilities Fortnightly, September 15, 1983.

4. This can be seen from the structure of the interstate rates filed by AT&T, in conjunction with the access charge tariff filing. NTS and WATS rates were decreased overall, while private line rates were generally increased.
8. The substance of this belief can be seen in the Embedded Direct Analysis (EDA) studies performed by the BOCs for most state jurisdictions. See W. H. Molody, "Cost Standards for Judging Local Exchange Rates," in Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries (East Lansing: Institute of Public Utilities, 1983).
9. For an excellent discussion of the history of separations agreements, see Gabel, Separations Principles.
11. Cost definition looms large in determining whether bypass is "uneconomic." Allocation of costs is a major issue in the telecommunications industry. See W. G. Bolton, "The FCC's Selection of a 'Proper' Costing Standard after Fifteen Years—What Can We Learn from Docket 10128?" in Diversification, Deregulation, and Increased Uncertainty in the Public Utility Industries (East Lansing: Institute of Public Utilities, 1983). The apparent cost standard for judging whether bypass is "economic" or not is based on allocating NTS costs on a per-loop basis to end-users, rather than on usage or some other measure.
12. For example, radio spectrum used by alternative local distribution systems is not priced properly. See O. M. Hatfield, "Pricing Telecommunications Services under Conditions of Technical Change and Partial Deregulation,"
Indeed, the major specific example of bypass discussed in the access charge hearings before the Kansas Corporation Commission in Docket 127.140-U (Phase IV) was that of McDonnell-Douglas in Missouri. Southwestern Bell's witness in Missouri indicated that the McDonnell-Douglas bypass was economic. See the cross-examination of Jerome Lucas in Missouri Case Number TR-83-253.

"Vulnerability" to competition can come from overall cost levels as well as alleged "irrational rates." Prior to restructuring rates to shift joint and common costs to monopoly markets as a result of competition, an inquiry into the efficiency of telephone company operations may be appropriate. Perhaps any perceived pricing problems are aggravated by the size of overheads. The large proportion of joint and common cost inherent in telephone company operations makes this point important. Ratebase regulation is essentially "cost plus." Regulation as an institution has had difficulty encouraging or enforcing efficiency in utility operations.

See also T. J. Tardif, "Pricing and Marketing in the Competitive Local Access Market: Principles and Methods," p. 387, presented to the Ninth Annual Rate Symposium, under the auspices of the Institute for Study of Regulation.


In fact, Bell Communication Research is to conduct research regarding bypass applications for the BOCs. See transcripts, p. 1875, Southwestern Bell rate case before the Kansas Corporation Commission, Docket 137.534-U. SWB intends to "bypass itself" if necessary to maintain revenues. See speech by John Hayes, as reported in Telecommunications Reports, August 1, 1983.


AT&T has recognized that it cannot recover a significant portion of CPE investment due to the competitive nature of that market. It is up to state regulators to ensure
that similar write-offs are taken if necessary and appropriate as the local telephone companies upgrade to provide new services as part of the long-term company marketing strategy to meet competition and enhance profitability. See also Trends in Communications Regulation, November 1983, p. 4.


EFFECT OF THE MODIFIED FINAL JUDGMENT ON THE INDEPENDENT TELEPHONE COMPANIES

Basil J. Boritzki

When I first learned the details of the proposed Modified Final Judgment (MFJ) filed by the Department of Justice and AT&T on January 6, 1982, in the U.S. District Court, I was not only taken by surprise but wondered whether, when the public recognized the inevitable impacts of the break-up of the Bell System, a shift in direction of the forces of public opinion toward reevaluation of the wisdom of segmenting the economically integrated switched network would occur.

In the nearly two years that have elapsed since the initial announcement, such forces have not developed. Our society is headed into an era of fragmentation of the heretofore integrated operation and functioning of the telecommunications industry.

In discussing the impact of the MFJ on the Independents one caveat is in order. To a large degree, if not totally, the impacts are, strictly speaking, the consequence of the availability of the advances in telecommunications technology made available to all, by the courts and the FCC, coupled with all three branches of the federal government encouraging and fostering competition in the interchange market, not the MFJ per se. Thus, although the MFJ may have speeded

Note: Many of the views expressed in this paper are those of the author and are not those of the United Telephone System.
up the process, this development is a consequence of the competitive environment that has been established in the interstate toll business and the consequental need to develop even-handed treatment of interexchange carriers by all local carriers. The changes confronting the independent industry today from cost related pricing to a break-up of the historic partnership arrangements would have occurred even without the AT&T divestiture of the local Bell companies.

To understand the impact of the MFJ and competition on the Independents, it is necessary to understand initially how the Independents in the pre-AT&T divestiture environment received compensation for the use of their resources in providing toll services to the public jointly with the Bell System under common tariffs.

In the pre-AT&T divestiture environment, each of the independent operating telephone companies had a contract (called a traffic agreement) with a Bell operating company (BOC). In a few instances an Independent company may have contracts (traffic agreements) with more than one Bell company if the Independent has operating territories within the "settlement area" of each of these Bell companies. For example, an Independent company operating in Ohio may have one contract with Ohio Bell and another one with Cincinnati Bell.

These "traffic agreements" contain not only telephone traffic routing agreements, point of connection agreements, and so forth, but also the specific methods that are used in calculating compensation the Independent company is paid for the utilization of the Independent company's resources in processing both intra- and interstate traffic provided under common tariffs. These include the interstate toll tariffs and intrastate toll traffic under common intrastate toll tariffs.

While these methods of compensation may vary to some degree from one Bell operating company to another, the methods used to determine the compensation the Independents receive for the utilization of their resources in the provision of interstate toll services is reasonably uniform. In essence, for interstate services they provide for the Independent company's recovery of expenses and taxes allocated to the interstate services provided under a common interstate tariff plus an industry-achieved (nationwide) interstate earnings ratio on the Independent's investment allocated to the interstate toll services provided under common tariffs; that is, all companies (Bell, Independents, and AT&T Long Lines) achieve the same overall earnings ratio on the investment allocated or assigned to the interstate operations rendered under common tariffs.

Independents are compensated for the utilization of their resources allocated or assigned to the intrastate toll services provided under common tariff in a similar manner except that the type of earnings ratio applied to the Independents' investment allocated or assigned to intrastate toll services varies among the various state jurisdictions from (1) an achieved intrastate toll earnings ratio in some state jurisdictions to (2) a total state achieved earnings ratio of the Bell operating company within that state jurisdiction to (3) an overall (state plus intrastate) earnings ratio of the Bell operating company within that state jurisdiction.

In effect, if Bell System jurisdictional tariffs generate sufficient revenue, then: first, all of an Independent's expenses and taxes allocated or assigned to toll services rendered under common tariffs are recovered under the existing traffic agreements; second, an additional amount is also paid to reflect the industry's achieved earnings ratio for the interstate operations (nationwide) and for the specified type of earnings ratio achieved in the individual state's jurisdictional operations. The Independent bills its customers the toll tariff rates, collects these revenues, and remits them to the Bell operating company with whom it has a contract so that the interstate and intrastate settlement (earnings) ratios can be calculated. The Independents, in effect, operate on a cost-plus basis in the provision of toll services under common tariff, plus being the achieved earnings ratio for the interstate (nationwide) operations or the specified earnings ratio in the traffic agreement for the Independents' investment allocated or assigned to intrastate toll services. The burden is placed on the Bell System companies to structure the level of the rates and charges they produce an adequate earnings ratio for all participants. This scheme is commonly called the rate averaging and pooling process and is the vehicle used to achieve economic integration.

Nationwide average settlement schedules available to smaller Independent companies have been designed to approximate these settlement results for Independent companies who do not conduct regular individual cost allocation studies to specifically identify their discrete cost and investments allocated to the interstate and intrastate toll services rendered to the public under common tariffs.

The MFJ requires cancellation of the Division of Revenue (settlement) contracts between AT&T and the BOCs. Under the terms of the MFJ, the BOCs are required to file access charge tariffs (both state and interstate). Access charges will become their method of receiving compensation from AT&T Communications (currently known as AT&T Long Lines) as well as other interexchange carriers for use of the BOC's exchange access facilities to originate and terminate interexchange traffic (as exchange/interexchange is defined in Section IV of the MFJ).

Interexchange traffic is defined as service between geographic areas known as Local Access and Transport Areas (LATA) or Geographic Market Areas (GMA). Under the terms of the MFJ, telephone traffic that originates in one LATA...
and terminates in another LATA must use the interchange facilities of an interchange carrier. The MFJ prohibits (with a few minor exceptions) the BOCs from transporting traffic from one LATA to another.

To comply with the MFJ requirements, the Bell operating companies have filed interstate access charge tariffs with the FCC. They have also filed intrastate access charge tariffs with the various state regulatory commissions.

In Docket 78-72 the FCC also has determined that the independent companies (as well as the BOCs) must file intrastate access charge tariffs and report the increasing visibility of an independent carrier to originate and terminate interstate long distance traffic within the geographic operating area of the independent.

Diversiture will break the Bell System into eight economically separate pieces, that is, AT&T (including AT&T Communications) and the seven regional BOCs. A direct result of diversiture will be the termination of the current toll settlement methods used by the independent, that is, the traffic agreements to be cancelled effective December 31, 1983. The contracts or tariffs that will replace the cancelled traffic agreements will result in the increased visibility of the independents' costs of providing access to AT&T Communications and other interchange carriers. That is, the independents will no longer be able to simply bury all of their costs in the pooling process; ultimately independents will be required to recover their costs through a cost-based, tariffed rates for each element of access (except for high cost local loop plant that is supported by a universal service fund—which also will be highly visible).

Furthermore, as time passes, interchange carriers may be expected to elect to perform for themselves functions that are now performed by the independents and the Bell operating companies where it is more economically efficient for the interchange carriers to do so rather than pay higher costs to the independent or the BOC to perform such functions. The economic issue is currently being addressed on a state basis. First, there is the possibility that AT&T Communications will elect not to utilize independents' toll operator positions and toll operation in dealing with the subject of an intraLATA toll pool. Second, BOCs that have no independent toll service positions will be unique to the independents as opposed to the newly invested BOCs.

Furthermore, it is more likely than not that AT&T Communications will move toward dealing directly with larger customers and bill such customers for interexchange toll services rather than deal with them through a third party (that is, the independents). This will end whatever leverage or advantage that accrues, in most instances, to the local exchange company as a result of flowing monies from the local company to the toll company.

The requirement for cost-supported access charges is an artificial inflation of the Bell companies' costs as a direct fall-out of the diversiture. Under the FCC access charge plan, the basic decision concerning average toll traffic sensitive rates is vested in each individual company; that is, a BOC or an independent can elect to join or not to join the Exchange Carrier Association's (ECA) voluntary group of independent BOCs elected to join the initial traffic sensitive pool.

While many independents also elected to join the ECA pool, it is not clear who else in a year or two will be in the national pools. Most likely voluntary pooling will survive only as a means of administrative convenience. That is, larger companies that have the experience and resources to file their own access charges will do so. The economic significance of pooling, consequently, will diminish as low cost companies (BOCs in particular) elect to stand on their own.

The second example of the pressures against pooling relate to intraLATA toll. The BOCs are left with short-haul toll--typically the least profitable piece of the toll market based on current rate levels. The industry, per Judge Greene, is also exposed to potential intraLATA competition. In instances where intraLATA competition is authorized, the ability of a BOC to engage in cost averaging will be severely constrained.

Thus, the BOCs' ability to carry the higher cost independent through pooling in an intraLATA toll market is doubtful. The issue is currently being addressed on a state basis. At the time of the drafting of this document, the following are a few examples of what is going on in the various states:

- The BOC plans vary from statewide uniform rates with pooling to bill and keep.
- The rate of return on the intraLATA toll pool varies from the current frozen SPF to no NTS costs;
toll business varies from a mandated 12.75 to an achieved on either a statewide pool or even, as proposed in one state, a LATA by LATA pool; and (4) one common thread of almost all plans is the maintaining of statewide uniform rates in 1984, a concept that may be maintained for the short run but is doomed long term.

Independent company customers in the long term face relatively higher short haul toll rates, or alternatively higher local rates if intraLATA independent to Independent [I-I] toll losses are buried in the local rates.

Events since the initial filing of the proposed MFJ on January 8, 1982, have brought forth a few shorthand terms to describe the locus of the Independents in the AT&T divestiture process and the post-divestiture environment. The terms "transparent" and "transparency" were used, for example, in the drawing of BOC/LATA boundaries. The term "as if" was used to treat the Independent territory as if it were Bell territory in the drawing of BOC/LATA boundaries. The term "shadow effect" was used to forecast that, if the BOCs are required to do something in the post-divestiture environment by either the court or the FCC, such a ruling would establish a precedent that most likely would become a future requirement for the Independents also.

Furthermore, the FCC has indicated that exceptions applicable for the BOCs might not be appropriate exceptions for the Independents with reference to equal access because such exceptions would not spur the Independents to provide equal access.

The MFJ requires that the BOCs in the divestiture process transfer ownership of certain interchange facilities to AT&T. Where certain facilities will continue to be jointly used by AT&T Communications for the processing and hauling of intraLATA traffic, and by the BOC for processing and hauling intraLATA traffic, ownership vests in the predominant user with the other party (either the BOC or AT&T-C) leasing the facilities from the predominant user under a shared use contract.

In the divestiture process, AT&T or the BOC will obtain ownership of facilities that are predominately used to process and/or transport its traffic. Thus, contractual relationships will continue to be an important element in industry relationships even after divestiture and access charges.

The entity of AT&T Communications will be responsible for processing and transporting interLATA traffic. However, AT&T-C will be utilizing in many instances facilities it has acquired from the BOCs to also process intraLATA traffic for both the BOCs and the Independents. This circumstance requires new contracts to compensate each party for the use of its property since the existing settlement and division of revenue arrangements will have been terminated.

A contractual arrangement would also require the indepen-
dent company to pay AT&T Communications for any processing of intraLATA traffic of the Independent utilizing the facilities owned or leased by AT&T. For example: If AT&T-C acquired in the divestiture a former BOC toll center on which an Independent company exchange homes, AT&T-C would charge the Independent for processing any intraLATA call out of that toll center. On the other hand, AT&T-C would assume the cost for processing any interLATA call out of that toll center.

AT&T-C has offered to enter into lease arrangements with the Independents, leasing the Independent company's facilities and resources devoted to interexchange interchange (interLATA transport) and the processing of interLATA traffic.

As an alternative to the lease, AT&T-C is also offering to AT&T the Independents what they call a "business as usual" arrangement as a method of compensation for interLATA use of an Independent's interchange facilities. Under this arrangement the Independent would, through the assignment and allocation process, allocate expenses, taxes, and investment to the interchange interLATA category, plus an earnings ratio at the achieved AT&T-C earnings ratio. The Independent would still be obligated to pay AT&T Communications for any intraLATA traffic processed over equipment owned or leased by AT&T.

Centel may follow a third course. If Centel is unable to negotiate acceptable arrangements with AT&T for the provision of interLATA facilities and services, they may elect to provide those interLATA facilities under tariff. That is, AT&T (and, presumably, any other interchange carrier) would obtain interLATA facilities from Centel companies pursuant to filed tariffs rather than through negotiated financial arrangements.

Many in the industry foresee the emergence of selected competition in the supply of intraLATA toll service, and in such a potentially competitive environment the development of intraLATA access rates and charges to the suppliers of intercity toll services within the LATA.

As heretofore stated, the visibility of the Independents will be increased through display of the access rates and charges and any subsidy received from a high cost fund based on the Independent's discrete costs.

While each LATA or GMA is viewed as an "island" which must offer exchange access to interexchange (interLATA) traffic, Independent companies "associated with" a Bell's LATA or another Independent's GMA are no longer necessarily economically integrated with other telephone companies or local exchange carriers also within that LATA for the purpose of providing what will become intraLATA short-haul toll traffic.

Over the long term, within each LATA or GMA, the Independent must stand on its own feet and can no longer rely on
the pooling and rate averaging mechanism to shield its costs from being reflected in the rates it will charge for its intralATA toll services.

With the obsolescence of the Kingsbury Commitment and Hall Memorandum by the MFJ, it can reasonably be expected that some consumers and business groups residing in territories served by independent companies may seek the transfer of the franchise to serve their geographic area from an independent to the BOC serving nearby areas within the LATA where it appears in their economic interest to do so. The purpose for such a transfer would be to achieve some measure of cost averaging by invoking the community of ownership arguments for rates in that area. Without such a transfer, cost averaging beyond what may already exist with the Independent cannot be achieved because there is no community of ownership for the geographic area served by the Independent and the BOC.

In summary, the implementation of the MFJ will impact the Independents in the following ways:

(1) Economic integration with all parties sharing a common achieved rate of return is severed, and new arrangements will be established to compensate independents for the use of their resources in the processing of interchange traffic as interchange traffic is defined by the MFJ.

(2) The FDC has prescribed (and expects to modify over time) an access charge mechanism whereby local exchange companies will file rates that interchange carriers will pay to access the local exchange facilities at originating and terminating interstate interchange traffic (inter-LATA traffic).

(3) The menu of access items offered to interchange carriers by local exchange companies, an interchange carrier will pick and choose which items of access it desires to purchase from the local exchange carrier, and which items of access it desires to perform for itself (for example: toll charging, rating, billing, collecting, operating service functions, operator office functions). Interchange carriers may reasonably be expected to elect to perform most economic method of performing these functions, that is, purchasing them from the local exchange carrier, from others, or performing them themselves.

(4) The MFJ also requires that the Bell operating companies provide access to interchange carriers (including AT&T Communications) to intrastate interLATA traffic. In the jurisdiction over such access rates and charges currently resides with the state regulatory commissions, it ultimately appears more likely than not that access rates to interchange carriers for traffic sensitive plant will be identical to the interstate rates (if such rates are cost based and the methods of determining such cost are also identical or comparable).

(5) It is unlikely that pooling of intrastate toll costs can continue in the state jurisdiction in the new environment in which the BOCs are prohibited from providing facilities to process and transport intrastate interLATA toll traffic. It is more likely that eventually there will be separate and distinct intrastate interLATA toll rate structures reflecting interLATA access and toll transport cost as well as separate and distinct intrastate toll rate structures reflecting interLATA access and toll transport cost.

(6) How these intra- and interLATA toll access and transport costs are defined within each state jurisdiction will likely determine whether the facilities of the local exchange carriers will be used by customers and intercity carriers or whether they will seek alternate sources of supply in meeting their intercity telecommunications requirements. Pricing access too high will drive users to alternate sources of supply.

 Independent company costs will become highly visible.

(8) In the intrastate jurisdiction, state regulators must decide where to place the burden of recovering costs that will not be recovered through intrastate access charges that are collected from interchange carriers or through intralATA short-haul toll rates.

(9) Independents in the "island" environment must become the least-cost provider of telecommunications services and facilities in the geographic area they serve to attract interexchange carriers to use the Independents' facilities to originate and terminate intrastate traffic: the Independents' least-cost advantage must be reflected in their tariffed access rates.

(10) Independents will no longer be shielded by the Kingsbury Commitment and Hall Memorandum where public pressure is exerted to merge independent geographic areas with Bell operating areas.

(11) Where the Independents are now, or truly become, the least-cost provider of services or facilities needed or utilized by intercity carriers to originate and terminate intercity traffic, they will not only continue to survive, but prosper if they are permitted to reflect these "least costs" in rates without subsidy mark ups. To the extent that they do not become the least-cost provider and the most economically efficient provider of services or facilities to originate and terminate intercity telecommunications business, they can expect that they will lose such business to others. Independents may also expect the intercity carrier will find a way to provide such services or facilities at the lowest possible costs to the intercity carrier.
INTERCITY SERVICE COMPETITION AFTER DIVESTITURE: THE ROLE OF THE NEW ENTRANT

Andrew J. Mergesom

My topic is the role of resellers and value-added carriers in the postdivestiture world. The stock market, which is always perfect in its assessment of corporate prospects, is taking a fairly dim view of the future for resellers. The two largest of these companies, Allnet and U.S. Telephone, have watched their stocks drop from $12.00 to $6.00 and from $10.00 to $4.00, respectively. In fact, the only major reseller which has not experienced a significant drop in its share price is LexTel; if pressed, I might admit that the fact we are not publicly traded may have something to do with that.

What is going on in the marketplace to produce such a dim view of the prospects for resellers? Nothing, really. The marketplace continues to offer significant opportunity. The problem, of course, is the government. According to a recent Wall Street Journal report, "Outright panic has hit a secondary group of long distance concerns known as resellers because they typically lease all of their lines from AT&T and other phone companies." The Journal indicates that "some analysts believe the FCC decision covering costs for leased lines will put a number of these concerns out of business." The same article quotes a mutual fund manager who concludes that, even though efforts such as the congressional legislation may slow the process, he does not "think the FCC is averse to letting most of these resellers go under."¹

As someone who began his career in the government and then worked for an independent telephone company before joining a fast-growing reseller, I greet this assessment with some consternation. In bracing for this winter's plague, also known as access charges, we are suffering the side effects of a belt tightening vaccination. Having just gotten a company car for the first time in my life, I may be forced to give it up. But never fear, in its place the Reagan administration is giving me a business cycle to ride to work!

The rest of my discussion will focus on whether this gloomy assessment of resellers is valid, if so, why, and whether, from a public policy point of view, anything should be done about it.

So far, I have mentioned only resellers, even though I am charged to address value-added carriers as well. Let me explain why with a few definitions. A resale carrier is an entity which purchases telecommunications service from another entity and sells it to its customers, with or without changing or adding to it. A value-added carrier is a company which successfully resells at a price greater than the price which it paid for the service. Notice that packet switching, speed and code conversion, and everything else associated with data communications figured not at all in my definition. In a free enterprise economy this market test is the heart and soul of adding value. You and I may think that adding someone's name to the pocket of jeans adds or does not add value, but IBM adding its name to a home computer manufactured by someone else adds value or it does not, but our individual views are irrelevant. The marketplace defines who adds value and who does not.

In what ways does a resale carrier add value today? The example which has gotten the most favor in Washington is the company that combines leased lines, local network access, and sophisticated computer systems to provide data communications services. These carriers, such as Telenet, Graphnet, and others, have historically been a favored group, AT&T having very early on excepted "composite data service vendors" from its general no-competition proscription.

The resellers offering voice services have added value in other ways. In some cases the underlying communications services are enhanced by offering billing detail on WATS-like services, for example. But, for the most part, the voice resellers have added value by providing services functionally similar, but technically inferior, to MTS and WAWS at greatly reduced prices. They have shown that there is a significant group of customers who are willing to put up with a reduced quality of service if they are able to pay 80 percent or less of the prices AT&T charges. More recently, these companies have begun to employ sophisticated microprocessor devices to eliminate some of the technical inferiority which springs from unequal access. For example, for its larger
exploiting tariff peculiarities. While some do, the real marketplace is far richer and far more subtle than this.

I suspect, however, that some may think I am being a bit disingenuous. This fellow is spouting off about adding value. He and his kind are in business for one reason—the EMFIA tariffs. He only pays 25-35 percent of what AT&T pays for local network access and, on the basis of that, offers a reduced price. That is true, I rejoin, and we get what we pay for. I have had a fairly direct marketplace experience with the value of unequal access in the past six months. What I have learned is that customers demand a 20-25 percent savings in order to tolerate the consequences of inferior access—from digits, inferior transmission, and so forth.

Let us look at two or three years into a dogfight on this issue, however, and let us assume it away. Let us transport ourselves three or five or ten years into the future when equal access is available. What, then, is the role of today's emerging competition? For some will be dead and buried, and some will have been merged. But, given reasonable government policies, I think a significant number will have survived and prospered. Some will be national carriers, but I suspect that a significant number will be regional in scope. Whether by reselling or by providing services through their own facilities, I believe the characteristic they will share is that, within the area they operate, they will be among the low cost producers. At least for the next ten years or so, into the future telecommunications will be predominantly a voice business, and it will have strong commodity characteristics. Some product differentiation will exist, but for the most part price will be the key issue. Those carriers which are regional will make agreements with carriers operating in other regions to exchange capacity and traffic, leveraging a regional position to provide universal access to those of their customers who demand it.

Those who follow the airline deregulation experience will, I hope, recognize themes heard before. It was widely believed in the time of deregulation that just a few national carriers would come to dominate the airline marketplace. What has happened, of course, is that the real success stories are the wholesale carriers like Air Wisconsin, Empire Airlines, and National Carriers like US Air, which have leveraged strong regional positions into the national marketplace.

I draw an analogy to the airline experience, of course, immediately. It raises the issue of service to the less densely populated regions of the country. Here the analogy breaks down, at least from today's viewpoint. The access charges which the telephone companies have filed are highly averaged. For example, local transport charges may vary only with the distance between the interexchange carrier's point of presence and the calling or the called customer. Ten miles is ten miles regardless of whether the route in question has a cost
of a, 10x, or 100x. AT&T's Intercity rate structure is priced on the basis of the airline distance between the calling and the called parties. Carrier points of presence will tend to be at the center of population concentration in the Local Access and Transport Area (LATA). In this environment, competition in rural areas will depend on a host of complicated factors too problematical to be addressed here. In general, I suspect that competition will occur in rural areas to the extent that they are along the routes of the Intercity carriers and not otherwise. There are, of course, some exceptions. Rochester Telephone, for example, studied its cost of Inter-LATA transport and found that distance was not a significant explanatory variable. As a result it has petitioned the FCC to allow it to have a local transport charge that is invariant with respect to distance. If I worked for an Intercity carrier that served the Rochester LATA, I would be actively soliciting business from all of Rochester's customers, including the rural ones, especially, because they have not been actively solicited in the past. If I were a regulatory official concerned about rural telecommunications, I would be scrutinizing the access tariffs very closely. I suspect that if the carriers had really justified the distance sensitivity of the local transport charges, the result would hold, and I would expect intense competition in rural areas. This is true because the major metropolitan areas will be the scene of intense price competition, including price wars, and the emerging entrants have, by necessity, become specialists in low cost, low density systems. On an unsubsidized playing field, I think the new entrants could dominate the low density market. While I am sure my discussion may not agree with me— and his view is just as important—I think AT&T does not underprice because I love rural Michigan, and I would love to dominate its intercity telecommunications.

This is a very sanguine view of the long-term prospects for today's new entrants, and I would be up where I am today if I did not believe it. But what about all these examples of scale arguments— all of those studies showing that AT&T's marginal cost is zero, more or less? To paraphrase a gentleman from the independent telephone industry, we all use these bricks, and we all use the same mortar. What matters is what you build with them. Delta and Braniff both flew 727's but with vastly different results. Similarly, we all employ basically the same intercity transmission and switching technologies from basically the same manufacturers. But an awful lot more than the marginal cost of transmission and switching goes into the provision of telecommunications services. The economist's notion of technology—which is the one that is relevant to marketplace success—includes much more than semiconductors; it comprehends all of the methodologies that companies use to produce goods and services. How our customer service systems perform, for example, is just as relevant as our microwave works.

More prosaically, the economies of scale that do exist—and they do—are largely exhausted at levels that are reasonable in relation to the size of the market, and they are a function of density, not overall size. In other words, if you are a $100 million carrier with a 20 percent share in the markets you serve you are probably okay, but if you are a $1 billion dollar carrier with a 4 percent share, you may well be in trouble. Even here the intermediate market in transmission capacity is significant in that it allows smaller carriers access to economies of scale indirectly. It is on this basis that I predict the success of strong regional carriers.

Now for the bad news. This rosy view of the future for new entrants was, you will recall, conditioned on the assumption of reasonable regulatory policies. That brings me back to the issue with which I began. The market evidently believes that the FCC is content to let us go out of business. The issue, of course, is postinvestment rate structure. This includes both the access tariffs and the rate structure of AT&T's Intercity services, particularly in the period before equal access exists.

Put very simply, unless the tariffs which have been filed by the various parts of the old AT&T are altered in several fundamental respects, its farewell gift to the U.S. telecommunications industry will be enormous barriers to entry which should not and need not exist. My purpose here is not to debate the differential for interior access. I have already said the market demands approximately 20-25 percent for unequal access. Unless one has had the experience I have in marketing the service and cost-justifying trunk side dialers, special telephones, and so forth, one probably would not believe that and, frankly, I did not. Instead, I want to focus on other issues which in the long run will have even more serious consequences. Having a great deal of regard for the BOC personnel who prepared the access tariffs, I do not believe that tariffs were intentionally constructed to be anticompetitive. I take at face value statements by the BOC executives that they are not concerned with the market shares of the various Intercity carriers. But in their zeal to protect the newly independent operating companies from financial and operational risks, they have placed a burden on the shoulders of the new entrants which they cannot sustain.

Let me illustrate what I am talking about. Under the Exchange Carrier Association and BOC tariffs, to be assured of having access capacity available it must be ordered two
years—that is years—in advance. During the order period—before service is ever received—advance payments equal to a full year’s normal payments must be made, and these are held by the operating company without the payment of interest. In effect, the operating companies’ construction budgets are being funded by zero cost capital from the new entrants. And after having made these payments, the tariffs expressly state that there is no assurance of receiving the facilities on the order date. Imagine Apple Computer ordering their chips this way; the Macintosh would be rotten before anybody ever checked it.

If, on the other hand, a carrier wishes to order capacity on an if available basis, it can do so on approximately 60 days’ notice. But even here the carrier must pay, under the ECA tariff, a nonrecurring charge of $0.00 per bascircuiting charge of $0.00 per minute—that is minute—of capacity. Obviously, a very large carrier like AT&T can add each year an increment of capacity that is small in relation to its total service. In contrast, an emerging carrier trying to reach an acceptable point on the cost curve will probably add capacity during 1984 that is larger than its existing capacity. In this latter case the effect of large nonrecurring charges is very severe.

Notwithstanding this effect, the up-front charges might be reasonable if the network capacity being created was only useful to serve the particular carrier ordering the capacity. This, of course, is not the case. The tandem switching, interoffice trunking, and central office switching are completely fungible—i.e., they can be used by another carrier if another carrier wishes, since the total amount of interLATA traffic is within a reasonable range, fixed. In short, the risk that an interLATA carrier will not use the capacity will not be diversified away by the local operating company, and in a competitive market this is what would happen.

One aspect of the access tariff which is not fungible and that is the access connection between the intercity carrier’s point of presence and its serving wire center. A nonrecurring charge or a minimum service period is appropriate for this telephone company investment since it is unlikely to have another customer for this facility if the intercity carrier does not make use of it. This is precisely analogous to the case of any large single user ordering a significant number of loops, and the policy applied should be nondiscriminatory.

Another aspect of this access ordering process which is very troublesome is that the nonrecurring charge is not the carrier order capacity into the LATA as a whole, but on an end office by end office basis. This is both impossible and unnecessary. Once again, the BOCs are not going to engage in special construction of trunks to every end office to which an emerging carrier orders capacity. They will establish a trunking network into an access tandem sufficient to serve the market requirement and then allocate it on a real-time basis to the carriers needing it. The sum of the individual carriers’ requirements will be equal to the market requirement, and the entity with the best data to forecast this is the local operating company. If the new entrants are really required to order capacity this way they will be compelled to make wild guesses and then pay the penalty in the form of substantial minimum usage charges. Meanwhile, some other carrier will be making use of the capacity and paying for it as well. As a side note, if there is a surer way of restricting competition to the smallest end offices in the LATA—where the statistical risk of misforecasting will be greatest—I do not know what it is.

This is not meant to be an exhaustive critique of the access tariffs. I think I have made the point. The way I think about this issue is that prior to equal access the competing carriers are essentially ordering local business services. They are in most cases far from being the only entity in the local area ordering the most access lines. Those familiar with the access tariffs can imagine for the sake of entertainment what would happen if the telephone companies attempted to require ordinary businesses—many of whom have telecommunications departments larger than the emerging carriers’ entire staffs—to order local telephone service under terms and conditions substantially similar to the access tariffs. I cling to the naive belief, expressed several years ago at this conference, that the solution to this whole issue is to end all discrimination in the rates, terms, and conditions for use of local networks. I also believe that the surest way for the BOCs to avoid bypass if AT&T wants to, that is to facilitate, rather than impede, access to their networks by large users, including intercity carriers.

Let me make one point about AT&T’s intercity tariff. At the same time that AT&T filed its new tariffs it also petitioned the FCC for a waiver of the ICAM—the cost allocation manual—as it relates to allocating the premium for special access between MTS and WATS. The net effect of what AT&T wants to do is, without any attempt at analytical justification, to make the decrease in MTS prices larger than it would otherwise be and the decrease in WATS prices substantially less than it would otherwise be. According to AT&T, if this is not done MTS rates would only be reduced by 0.6 percent and WATS rates by 33 percent instead of the 15.5 percent and 10.7 percent reductions that were actually proposed. Amending the ICAM as AT&T recommends will, of course, seriously compress the margins of the traditional WATS resellers. From a purely business point of view I find this apparently arbitrary action difficult to understand. It may be related to the desire to make the MTS rate decrease "big enough" while maintaining AT&T’s profitability or it may be related to the historical debate over whether MTS
and MTS are "like" services and MTS rates are unjustly discriminatory, a subject which rivals in profundity the debate between Messieurs Feldstein, Steckman, and Regan as to whether the deficit affects inflation and interest rates. In time, however, and given the regulatory flexibility to do so, I suspect that AT&T may find it in its own interest to facilitate the resale of its services. That may sound preposterous, but then who ever thought AT&T would market its phones through retailers like Sears?

Finally, state regulators will have a major effect on the future for emerging intercity carriers. Certainly, they control intrastate access tariffs, but they also control entry into the intrastate marketplace. With the exception of a few states like Texas, the competitive carriers are forced to walk a tightrope on this issue, a fact often brought to the state regulators' attention by the BOCs. I do not think there is any question that in order to be viable in the long run, carriers must be able to offer intrastate as well as interstate services. The terms for entry into the intrastate market will therefore be crucial. I have the sense, however, that given satisfaction on other concerns they have, most state regulators will not seek to impede competition, and many will actively promote it. They do have a very difficult issue to confront, however, and that is the subject of intralATA intercity competition. In approving the MFJ, Judge Breyne decided that intralATA traffic would not be subject to the equal access provisions of the divestiture agreement. Therefore, even if a customer has presubscribed to a particular intercity carrier for intralATA traffic, all of his intralATA toll traffic will be routed to the BOC unless the customer manually selects one of the other carriers. The state regulators, therefore, face the question of whether they will permit intralATA intercity competition and, if they will, whether they will impose equal access obligations, including presubscription, on the operating telephone companies. This will no doubt be a lengthy debate.

The issue of intralATA intercity competition between the BOCs and the competing carriers is only one of a set of emerging issues in this area. The BOCs are being allowed to construct intralATA networks for their internal use, and there have been broad hints that several of the holding companies see this as the first step of their eventual reentry into the intercity marketplace. There have also been numerous reports that the operating companies intend to offer "least-cost routing" service to their local subscribers. I am not clear on what the difference is between "least-cost routing" service and resale, but I suspect that I may find out in the next few years. Perhaps there may eventually be seven very large and dominant regional sellers!

In conclusion, I have tried to demonstrate that the emerging intercity carriers, many of whom are resellers at-

Notes
2. Exchange Carrier Association, Tariff FCC No. 1, Section 5.4.1, p. 139. Note that similar provisions may be found in the BOC tariffs under the same section number, although the page numbers may vary.
3. ECA, Tariff FCC No. 1, Section 5.4.1, p. 149.
4. ECA, Tariff FCC No. 1, Section 5.2.1 (B), p. 127.
IN SEARCH OF A ROLE FOR THE STATES IN A COMPETITIVE TELECOMMUNICATIONS INDUSTRY

Charles A. Zielinski

For most of this century, the federal government (mainly the FCC) and state governments (mainly state public utility commissions, or PUCs) have divided regulatory jurisdiction over the rates to be charged for use of indivisible common carrier facilities to transmit and deliver electronic telecommunications. The jurisdictional line has been drawn by dividing expenses and investment associated with these facilities, defining one part as costs of providing interstate services, and calling the other part a cost of interstate services. The FCC regulates rates for services which bear the latter costs; the PUCs govern rates for services designed to recover the former costs. In this paper, a significant conflict between federal and state regulatory policies governing common carrier facilities and a possible approach to resolving the conflict are explored.

Nature of the Current Federal/State Policy Conflict

Each regulatory jurisdiction has responsibility for two types of costs: traffic-sensitive (TS) and nontraffic-sensitive (NTS) costs. Costs that vary with usage of the telephone network are traffic sensitive and constitute a relatively small proportion of the total costs of transmitting and delivering telecommunications. The large majority of total costs are NTS or fixed costs; that is, these costs are incurred to provide customers with access to the telephone network and do not vary with a customer’s use of the network.

Although there is no dispute that it would be economically efficient to cover NTS costs in charges to customers that do not vary with usage, that is, flat charges, and to collect TS costs from charges to customers that do vary with their usage, neither the FCC nor the PUCs have historically favored such a rate structure. Until recent years, the FCC has permitted a rate structure for switched interstate services that includes no flat charges. The PUCs allow a flat charge to collect some NTS costs, but significant amounts are assessed to customers through usage charges for intrastate switched services.

With the advent of competition for the transmission of telecommunications, the efficacy of these rate structures has come under increasing criticism. Because these rate structures are not only inefficient but also discriminatory, that is, they require certain customers, and the customers as a whole of certain local telephone companies, to pay more than the costs incurred to provide them with access to the telephone network, disadvantaged customers have a strong incentive to find ways to escape their cost burden. Competitive “bypass” alternatives, whose price is less but whose cost is often greater than that caused by use of the telephone network, have begun to afford the escape route for disadvantaged customers.

To improve efficiency, reduce discrimination, and discourage uneconomic bypass, the FCC has embarked on a plan to reform rate structures for interstate services. The FCC wants to introduce a flat charge to all customers for access to the interstate telephone network. This charge would be designed to recover most of the NTS costs that fall within the federal jurisdiction. The FCC would allow local telephone companies to recover their TS costs through charges that vary with usage to the carriers competing for the business of transmitting telecommunications between the cities. The rates of these carriers to their customers would, of course, also be based on usage of telephone networks. In part because of opposition from PUCs, the FCC has yet to implement its plan. A number of PUCs apparently regard the inefficiency and discrimination inherent in existing rate structures as effects they are prepared to accept in order to avoid flat interstate charges to customers. The PUCs argue that because flat charges increase the price of access to the telephone network, they threaten to undermine the nearly “universal service” that has been achieved in the United States by making access “unaffordable” for many customers. Moreover, the PUCs seem dubious about the availability of competitive bypass facilities to customers who are suffering from discrimination; they appear to favor charges
in rates to these customers to the minimum extent necessary to discourage them from turning to bypass technologies that are proven to be "real" alternatives. 2

Although the FCC addressed the concerns of the PUCs in developing its plan, it has said that it will explore them even further before it implements its plan. 3 At this point, it appears there will be no federal flat charges to residential or small business customers until at least mid-1995. 4 Whether the FCC implements such charges at that point, and the extent to which it permits such charges to cover the bulk of NTS costs under its jurisdiction, remains to be seen.

It also remains to be seen how the PUCs will, over the long run, deal with the NTS costs within their jurisdiction. In light of their opposition to the FCC's plan, PUCs are not likely to want to shift the NTS costs now being recovered from usage charges for intrastate services to intrastate flat customer charges. The PUCs may attempt to place the carriers competing for telecommunications transmission business pay for NTS costs through charges for intrastate use of local exchanges that are significantly higher than the charges the FCC will require for interstate use of exchanges.

Public Costs of the Federal/State Conflict

The rate structure policy conflict between the PUCs and the FCC is costly to the public in a number of ways that neither jurisdiction has explicitly recognized. While the regulators appear to be arguing simply about how total costs to the public should be apportioned among customers, their disagreement has already increased those total costs. Interested carriers have spent significant sums supporting either the FCC or the PUCs in various forums, and those costs are, of course, a part of those carriers' cost of service. Significantly different federal and state rate structure policies would further increase total costs.

For example, if competing carriers face significantly different interstate and intrastate access charges because the FCC and the PUCs disagree about the manner in which NTS costs should be recovered, the public will bear additional enforcement costs. With higher intrastate access charges, carriers will have an incentive to report more of their total traffic as intrastate. Some form of detailed traffic monitoring and reporting may therefore have to be developed to assure that the proper charges are being paid. Similar intrastate and interstate charges would eliminate the incentive to avoid the higher charge and thus save the enforcement costs.

Different federal and state carrier access prices would also increase administrative costs. If costs were recovered in the same manner in both jurisdictions, local telephone companies could maintain one cost accounting and pricing scheme applicable to both interstate and intrastate traffic. Without uniformity, they must administer and charge to the public the costs of two schemes.

Different pricing policies will also breed additional litigation. Both the PUCs and the FCC must hold their own administrative proceedings to define costs, analyze tariffs, and fix rates. Appeals from decisions in both forums to the courts will occur. Claims that PUC decisions undermine the federal scheme will provide additional grounds for appeal. These litigation costs are also part of the public's cost of service.

In addition, the public will bear "innovation" costs. The differing pricing policies will provide carriers an incentive to devote resources to escaping the more unfavorable pricing scheme. These resources could otherwise be devoted to initiatives that would reduce the actual costs of providing service to the public through technological innovation.

The straightforward way to avoid imposing these costs on the public is to preclude the possibility of conflicting federal and state pricing policies. Instead of dividing NTS costs between jurisdictions, they could all be assigned to one jurisdiction with tariffs to recover those costs filed in that jurisdiction under a uniform policy. 5 The merits of assigning costs and tariff responsibility to the PUCs or the FCC are considered below.

PUC versus FCC Administration of Access Service Charges

Both the PUCs and the FCC presumably favor efficient, nondiscriminatory rates that will discourage uneconomic bypass of local exchange networks and preserve "universal service." The source of their policy disagreement is rooted in the apparently contradictory nature of these goals. Efficiency, nondiscrimination, and discouragement of uneconomic bypass require the adoption of flat customer charges to recover NTS costs. But the latter charges, at least in the view of some PUCs, threaten universal service; that is, the PUCs are concerned that flat customer charges of a certain magnitude will make access to telecommunications networks unavailable for some significant number of customers. Thus, the policy disagreement apparently lies in the balance to be struck among agreed upon but competing goals, and the issue to be analyzed is which of the two jurisdictions has better capability to achieve a proper balance at the least cost to the public.

Maximum efficiency and nondiscrimination in rates can be achieved only by reflecting in rates all significant differ-
ences in the cost of serving customers, taking into account, of course, the costs of identifying such differences. Thus, a uniform nationwide rate structure would imply that the cost of serving all customers is the same. To the extent that costs vary significantly by company, geographic area, customer class, or even by individual customer, efficient and nondiscriminatory rates would reflect those differences.

It does not appear that the FCC and the PUCs are equally capable of analyzing and disaggregating costs in order to provide for the maximum reasonable degree of efficiency and nondiscrimination in rates. The FCC is a single regulatory agency in Washington which has historically regulated the American Telephone and Telegraph Company (AT&T) on the basis of its nationwide average costs. The divestiture of AT&T has created 22 entirely separate exchange telephone companies (BELLs), each with its own individual costs. Moreover, there are more than 1,100 independent companies that own and operate exchange networks throughout the country. It is highly unlikely that a single federal agency will be able to analyze efficiently the individual costs of all these companies. The PUCs, in contrast, have been regulating both the BELLs and the independent companies on an individual basis for many years. As a result, they have a greater capability to disaggregate costs and rates not only by company but also by geographic territory or by customer, to the extent warranted. In short, the PUCs are more likely to be able to achieve a high degree of efficiency and nondiscrimination in rate structures at the least cost to the public.

Similarly, the PUCs and the FCC do not appear to be equally capable of analyzing properly the universal service issue. The level at which a flat customer access charge may pose a significant threat to universal service is not likely to be the same in every area in the country. For example, a flat monthly charge of $20.00 in affluent suburban areas where average income is high would not be expected to have the same effect that such a charge might have in an inner-city neighborhood where average income approaches bare subsistence. The FCC, with its national perspective, clearly would have difficulty in recognizing all or even most such situations in analyzing the universal service issue. PUCs, in contrast, can be intimately familiar with individual areas of their states and be more likely to analyze them appropriately.

Nor is the FCC as capable as PUCs in analyzing properly the bypass problem. While the FCC may be able to assess the general capabilities of bypass technologies and their average costs, it is not likely to be able to analyze the utility and cost of each technology in the circumstances prevailing in all markets. For example, "short-hop" microwave transmission generally appears to be a very competitive bypass technology for individual customers. But microwave transmission normally requires unobstructed
PUCs from adopting inefficient ratemaking policies. PUCs could require that most NTS costs be recovered through nondiscriminatory usage rates to carriers and end-users in order to keep flat customer charges very low. Indeed, PUCs could even eliminate flat charges to end-users and recover all NTS costs through nondiscriminatory usage charges. In that event, charges for all usage of local exchange networks would far exceed the costs of usage, and rates for interstate and intrastate telecommunications would be grossly inefficient. To avoid gross inefficiency in rates, the FCC might have to promulgate and enforce some general NTS cost allocation and recovery rules as well.

What these problems suggest, of course, is that the benefits of unifying administration of exchange access charges under the PUCs will be illusory unless the PUCs make good faith efforts to strike a reasonable balance among the proper public policy goals. General FCC rules can point PUC initiatives in the right direction, but they cannot assure that the PUCs will exercise properly the institutional strengths that justify unification of access service tariff administration under their auspices. If the PUCs do not exercise their discretion properly, they will simply cause excessive appeals to the courts as well as petitions to the FCC to overrule PUC actions. In short, the litigation and related costs to the public that PUC administration of access charges should avoid would in fact be incurred by the public.

PUC administration of access charges may be an idea whose time will not come until the PUCs have demonstrated good faith efforts to pursue efficient nondiscriminatory rate structures. The PUCs have an opportunity to demonstrate their good faith under the current bifurcated jurisdictional scheme since they administer intrastate access charges to recover costs allocated to their jurisdiction. If the PUCs design their intrastate access charge polities in a manner that suggests reasoned consideration of, and good faith efforts to achieve, the proper public interest goals, they will make a strong case for administration of all access service tariffs at the state level. If they do not, it seems unlikely that PUCs will play a significant long-run policy role in an increasingly competitive telecommunications industry.

Notes

1. See FCC Docket 78-72, Third Report and Order 93 FCC 26241 (March 31, 1983); Reconsideration Order (September 21, 1983); appeal pending sub. nom., National Association of Regulatory Utility Commissioners v. FCC, Nos. 83-1129 et al. (D.C. Cir.).
Eric Schneiderwind

The remarks of Maurice Lamb, Basil Boritzki, and Andrew Margeson can be loosely characterized as a three-volume edition of Portnoy’s Complaints, subtitled “I Like Competition and Deregulation, But...” I hope these gentlemen do not take offense, but there does seem to be a common and rather plaintive theme to their remarks. All of them profess to support the new deregulatory and competitive thrust of the Federal Communications Commission. All of them seem to feel that competition in the telecommunications industry, while posing some problems, will result in a great new day for both consumers and telephone companies. But there is a strong qualification to these rosy predictions of the future, because all three of these gentlemen seek remedies, fixes, or just plain handouts from the government in order to be able to live in the deregulated era.

Let us start with Lamb. He strongly supports telecommunications deregulation but in essence wants government protection from one of the predictable outcomes of deregulation, which is bypass. In essence, Lamb is asking the government to anticipate a problem that has not been proven or quantified on any credible record and then move to solve this problem by a drastic shift in the costs of services away from the competitive area and on to what is currently the relatively noncompetitive arena of the local exchange customer. It is correct to assume that this action by government would make Lamb and his company vastly more competitive than under the current allocation of costs, but I question why government should intervene in such a drastic way without the benefit of any concrete evidence and certain in the knowledge that it has unilaterally acted to upset any competitive balance.

The theory cited by Lamb to justify the cost shifts requested is just that: only a theory. Many authorities would even challenge the basis of this theory that all nontraffic sensitive plant is caused by the local customer. To me, it has never made sense literally to give away a service which under any proper pricing theory could generate some revenue to support the requirements of the local exchange. Merely to give away this service at no charge when the bypasser would have to pay some cost to set up an alternative system is an act of folly that cannot be justified by any theoretical scheme. In essence, Lamb wants to improve his competitive position in the new age of deregulation by getting a tremendous amount of assistance from the government to make his competitive position possible. This does not sound like competition; it sounds like government protection.

Margeson from Lexitel, in his presentation, complains that AT&T has persuaded, or is in the process of persuading, the FCC to restructure the ENFIA tariff in such a way that resellers such as Lexitel will be driven out of business. Margeson professes to believe that the new era of deregulation in competition should allow competitive forces rather than government to restructure the industry. Margeson’s fix for this problem is—you guessed it—government action in the form of congressional legislation or federal intervention which would prevent the FCC from upsetting the current government-mandated competitive balance. This position would not be inconsistent in the case of many state regulators who favor continued government intervention, but it does seem a bit strange to hear this position from an advocate of deregulation. In fact, Margeson’s chief complaint, when stripped to the bare essentials, is that AT&T is competing against his company by requesting favorable action from the FCC. It is a matter of historical fact that AT&T has consistently used its ability to obtain favorable government decisions as a competitive tool. Why should Margeson expect that in an era of less government structure, AT&T would turn away from what has, in fact, been its strong suit? If unrestrained competition is the free-for-all that many advocates envision, then certainly no holds are barred when it comes to governmental lobbying or the use of government decisions to enhance a competitive position. Any restraint of this activity would involve necessarily more governmental intervention, and that is what Margeson has professed to oppose.

It seems to me that Margeson cannot have it both ways. One cannot expect less governmental intervention in the form of opening up new markets to companies such as Lexitel, while at the same time asking that the government in the executive...
branch or legislative branch preserve forever a type of discount rate structure that is advantageous to corporations such as Margeson's.

It is also somewhat unlikely, in my opinion, that state regulators will embrace a heightened level of intra-LATA competition when they are well aware that such competition could drastically reduce the revenues of exchange carriers and result in either lowered quality of service or greatly increased local rates. State regulators are much more likely either to restrict entry to intra-LATA traffic or to insist on some sort of 'fix' which will allow both the FCC and a reasonable contribution to the costs of providing local service. The position of such state regulators I think is entirely consistent, but I think Margeson's position is somewhat less than consistent.

Finally, among the industry representatives we have Boritzki, who has detailed many of the effects of the Modification of Final Judgment on the independent telephone companies. I find Boritzki's analysis to be useful, thoughtful, and probably correct from his point of view. Much of the material is objective in nature and forms a useful contribution to those of us who are trying to anticipate or deal with the problems sure to stem from the divestiture of the AT&T system. Clearly, the world of the independent telephone companies will never be the same, and they must not only adapt to significant changes in the way they have received revenues, but also be extremely vigilant to ensure that these changes do not leave them with significantly less revenue than before.

In one respect, however, Boritzki's comments do border on some of the tone that I find in Lamb and Margeson. His concerns regarding the stranded costs of AT&T if AT&T does not use independent toll service positions and personnel, as well as the dislocations that would occur if AT&T bills large customers directly, certainly indicate that the new world of competition, divestiture, and deregulation poses a great deal of problems for the independent telephone companies, as well as the BOCs. Boritzki's concerns are obviously well founded in that at the very least we can expect AT&T to use its new freedom to bill directly or possibly set up its own toll service positions as a bargaining tool to reduce the revenue or return currently enjoyed by independent telcos serving these services to AT&T. The era when we will see AT&T struggling to reduce its expenses at every level, and the pressure from these activities will fall equally on BOCs and independent telcos alike. This era will not be pleasant and undoubtedly will result in some yet undetermined reduction in the revenues enjoyed by BOCs and independent telcos providing services to AT&T. This is yet another indication of the fact that the cloud of deregulation and divestiture is not lined with silver for all concerned. There are significant dislocations ahead.

and I fear that one key strategy on the part of independent telephone companies losing revenue from AT&T will be the tried and true pattern of asking the state regulator to "make up the difference." In this instance, one can be sure that advantages of deregulation will be very pleased that some regulatory authority to affect rates still exists.

In summary, it seems to me that the three industry representatives, while doing homage to the concept of deregulation and divestiture, have accurately identified the problems resulting from this trend and have concurred that regulatory authority, as will be exercised by Congress, the FCC, or state regulators is the appropriate tool for dealing with all these unpleasant problems. I think this attitude can be summarized as one of hoping to have one's cake and eat it too.

I take a good deal more comfort from the comments of both David Brevitz and Charles Zielinski because I think they are taking balanced views of the merits and demerits of deregulation and divestiture and are attempting to pose thoughtful and balanced solutions.

Brevitz focuses on the phenomenon of bypass and provides a very detailed and thoughtful analysis of the flaws in the FCC attempt to cure an unquantified problem with an unjustified solution. He is correct, I believe, in identifying the major flaw in the economic theories used to justify the FCC's access charge position. Brevitz notes that the local network, and in particular the NTS portion of that network, will always be worth something to a customer considering bypass. The value of the NTS network at the very minimum would be equivalent to the amount that a bypass would have to spend to come some alternate facilities. If this is the case, then local state regulators should price the cost of NTS equipment to an inter-LATA carrier in an amount equal to or just slightly less than the cost of alternate facilities. Any other pricing strategy involves literally throwing away revenue.

This analysis and solution are gaining increasing favor among state regulators, and I suspect they are the wave of the future federal and state NTS costing decisions which will affect competitive markets.

Zielinski performs a valuable service by identifying the problems which could occur if separate access charge
structures are used for interstate and intrastate access. This is another position in growing favor among the observers and critics of the telephone industry. Zielinski notes accurately that different state and federal access charges could cause enforcement problems, arbitrage, and higher costs to the interexchange carriers involved. His solution of a single access charge for interstate and intrastate access seems appropriate. Obviously, I am not objective on the balance of his recommendation concerning the advisability of PUCs formulating the interstate and intrastate access charges. Yet, Zielinski does make the valid point that one centralized federal bureaucracy cannot be expected to deal with each of 1,300 separate telephone companies and remain sensitive to the economic and social conditions, as well as the potential for bypass, in each of these companies. Without such sensitivity, access charges formulated at a national level will be at best some average picture of the entire country and will not be suited to the conditions within each geographic or demographic region of the country. Clearly, from a historical perspective, state PUCs have administered regulatory systems which have required them to remain sensitive to the needs of each one of these telephone companies and fashion regulatory philosophies in rate cases which implement systems tailored explicitly to the needs of each telephone company. The FCC has never demonstrated a capacity for this sort of individualized rate-making, and it is doubtful that any feasible increase in staff or technical capability could allow the FCC to address the individual needs of more than 1,300 telephone companies.

Zielinski rightly points out that many state PUCs might not use their superior grasp of local problems to fashion balanced solutions; rather, they might yield to political or social pressures and simply avoid any increases in basic exchange rates to the immediate detriment of interexchange carriers and through the encouragement of bypass to the ultimate detriment of all customers. He makes the point that in order to gain the authority to determine interstate and intrastate access charges, state PUCs must show that they will administer the intrastate authority which they currently possess in a wise and balanced fashion.

I find in the comments of both Zielinski and Brewitz the germ of what I believe will be a future balanced and appropriate system of access charge regulation for the entire country. I believe, as they do, that bypass of the local system can be discouraged only by appropriate pricing strategies which attempt to maximize the income of local exchanges up to, but not beyond, the point of encouraging bypass in each individual region of the country. Such a system depends upon the use of broad guidelines for pricing directed from the federal level in terms of the basic revenues to be required from any class of customers, yet allows each state regulator the freedom within those broad guidelines to price access in such a way that maximizes revenues at the local level without encouraging uneconomic bypass. The thoughts of Zielinski and Brewitz seem to contain useful solutions which balance political and economic reality to a far greater extent than the presentations of Lam, Margerson, and Bortzki, which seem to focus simply on the need for greater government intervention in the competitive area, while at the same time insisting that the benefits of competition be retained by BOCs, independent telephone companies, and OCCs in the market.
achieved a commercial grade of transcontinental wire telephone transmission (FCC Telephone Investigation, Proposed Report, p. 190). State regulation of telephone rates was adopted by most states between 1907 and 1914. It was essentially cost-plus regulation. There was no federal rate regulation then and it came in name only under the Communications Act of 1934. Moreover, the independent companies were a competitive threat in the long haul business.

It was obviously following its economic self-interest when the Bell System (in that period from roughly 1907 to the early 1930s) assigned as much of its costs as possible to intrastate service, where increased costs permitted higher rates, and as little of its costs as possible to interstate, where service and rates were not regulated and there was competition. So AT&T established the board-to-board principle of cost separations. Under it the toll services bore only the direct costs associated with interexchange transmission facilities. All investment and operating expenses concerning the plant from the subscriber's instrument to the outward or inward bound side of the exchange switchboard were assigned to the local subscribers. Being assigned none of the common costs, the long distance services received a free ride on the local exchange facilities. There was an obvious upward flow of subsidy from the local to long distance services.

The state commissions tried to shift a portion of the local costs arising from the common use of local and long distance plant to the interstate services. The Bell System resisted until in Smith v. Illinois (1930) the Supreme Court ruled that because long distance services used local exchange facilities they must be assigned a portion of the common costs. It was left to the regulators to determine the appropriate criteria for sharing the common costs.

The parallel between that struggle which culminated in Smith v. Illinois in 1930 and the present one is striking. In both Bell has tried to burden the local services with all the common costs incurred in providing local and long distance services. In both there has been in a diversionary device which distracted the state commissions with their very limited resources from the main issue. In the earlier struggle the smoke screen concerned mostly the mythology about the fair value of the property on which a fair return might be earned (Smith v. Ang, 1898). It was very elaborate, but the cost of reproduction was taken to represent the present value of the plant, or an ideal plant designed according to the current state of the art—perhaps because of regulatory lag it should be according to a predicted future state of the art? Should it be cost new or less depreciation? And if the latter, which of a number of possible depreciation theories was appro-
priate? In the present struggle, the by-pass bugaboos is
the diversionary tactic--and a mighty hollow one at that--
as Brevitz's paper demonstrates abundantly. But in both
struggles the power of propaganda has been exerted in an
attempt to persuade the state regulators into submission
or acquiescence.

The Bell strategy paid off, handsomely, in the earlier
struggle. According to a report of the FCC Telephone
Investigation (Proposed Report, 1936, p. 435), the percentage return
on average plant in use on a net book cost basis enjoyed by
the Long Lines Department exceeded that received by the
associated companies from 1913 to 1920 by 174 percent (17.02
over 6.22), from 1921 to 1925 by 168 percent (19.21 over
7.16), and from 1926 to 1930 by 76 percent (13.34 over 7.63).

The mythical character of the present Bell (and FCC)
argument about subsidy is exposed if we realize that never
before or after the 1930 Smith v. Illinois case has there
been a policy of assigning to the TS plant the costs of
the local service the portions of common expenses (including
costs associated with investment) which they respectively
cause. Just that might logically have been the result of
the Smith case, but it did not happen.

What did happen, which is still taken by Bell and the
FCC to warrant the downward flowing subsidy argument,
is that negotiations were substituted for fact-finding. Bargains
were struck between Bell, state regulators, and the FCC for
aggregate dollar cost allocations to the respective jurisprudences.
Then these dollar amounts have been distributed according to jurisprudential cost separations designed to
reach the negotiated end result. It has been an unprincipled
bargaining process, not based on any theory of cost-caused
ratemaking.

Despite the factual irrelevance of jurisprudential cost
separations to the merits of cost causation in dividing common
costs between local and long distance services, the FCC's
Third Report and Order relies on them in prescribing flat
charges per access line (February 28, 1963). All NTS costs are
ultimately to be assigned directly to local subscribers
as access charges, regardless of whether such subscribers
make much or indeed any use of long distance service. What
about Smith v. Illinois? Has the FCC overlooked it?

What are these access costs which are alleged to represent
the fixed NTS costs associated with the local loop between
the central office and the customer premise? Lam's paper
assumes this to be self-evidently correct. It is assumed
that all costs of plant and operations relating to the loops
between exchanges and subscribers are supplied on an individu-
ual, line-by-line basis. Of course this is not the case.
In reality, only when one looks at the drop wire to the
subscriber's premise is there a direct relationship between
the loop facility and the individual subscriber--and even

there in many locations BOCs have been connecting two lines
in drop wire at that, even though only one was being used. As one looks up from the drop wire, what
one sees is an increasing degree of plant used for joint
service to subscribers, involving on occasion concentration
of lines before they all reach the central office (such as
party lines and community dial offices). The vast bulk of
local loop plant is common plant used by subscribers buying
a variety of different services--in principle just as with
exchange and interexchange plant.

According to a study by William Melody of the C&P over
the period 1975-1969, TS plant increased from 1975 to 1980
by 54.6 percent while NTS plant increased by 57.5 percent.

He concludes:

It is apparent that investment in NTS plant has increased more rapidly than investment
in TS plant; even though subscriber line growth has been very slow. Usage growth
has been much more rapid, especially toll
usage. This data seriously calls into question the
meaning of NTS investment in so-called
"access lines." The data indicates that
either NTS costs are really TS, or NTS local
exchange plant investment includes major
increases in upgrading and enhancing the
plant for special services. In fact, it
undoubtedly reflects both factors (C&P case
testimony, October 1983, p. 32).

One should also look at the accounts which go to make
up the access line category. In terms of investment, Melody
studied the C&P breakdown of both investment and expense
costs of loop plant. What he found was that for C&P

a portion of almost every investment account
has been assigned to the access line. This
includes commercial and general office space,
furniture, motor vehicles and supplies. The
access line investment is not the result
of identifying and directly assigning the
costs of the actual investment in loop plant.

Clearly, if one sought to identify
the actual investment in loop plant, the
majority of these investment allocations
would be excluded from access line investment
( Ibid., p. 29).

Likewise, Melody found that "portions of virtually every
expense account have been allocated to the access line. This
includes maintenance, depreciation, return and taxes on the
commercial office space and motor vehicles allocated to access line investment. It includes a share of commercial and marketing expenses, relief and persons and general services and licenses. To consider the access line account as NT and as representing expenses associated with the specific loop plant is misleading. To charge most of these allocated costs to local services as NT is wrong. In reality the access line category is a catch-all, or disposal, employed to reach a predetermined objective, the support of a particular division of total costs between Interstate and state jurisdictions.

The FCC's access charge decision purports to be based on cost causation. But the FCC made no independent determination of the costs of access. It simply accepted the current access classification used in jurisdictional cost separations—a scheme designed for an entirely different purpose. This attempt by Bell and the FCC to negate Smith, Illinois by justifying that user access charges, which Lamb supports, must be considered in light of these questions: Why do the Bell companies need this policy? Who will gain as a result? Who will lose?

The answer to the first question is simple. It is to raise the capital to finance the new enhanced ISDN. This ISDN is the second great change in the purpose of the telephone system. The original system was built to provide profitably a primarily local POTS. When long distance service was added at first it was necessary to go to a special phone booth equipped to handle long distance calls. Then the local plant was used to reach the entrance to the toll network. A simple expansion of the capacity of the exchange networks was all that was needed to supply long distance service. No fundamental changes were required in engineering design, functional characteristics, or cost characteristics of the facilities used. The first great change took place between 1916 and the 1960s, after the Lee de Forest three-element vacuum tube initiated redesigning and upgrading of the local exchange plant to meet the more stringent and more costly requirements of long distance service. This was the period when universal service was achieved. Virtually every phase of plant was transformed into circuits with better quality and conditioning, crossbar switching, the gauge of wire, spacing of telephone poles, design of the telephone instrument. So ten to thirty years after we were equipped with a system designed essentially for long distance, not local telephone service. But the new investment required came relatively slowly in that stage and together with increased operating costs it was absorbed incrementally by POTS users with slowly rising monthly phone bills.

The manner in which this is presently being carried out is by the implementation of computers, transistors, satellites, and so forth, and later digital (instead of analogue) techniques. The market for data telecommunications required very substantial upgrading of local exchange plant. What distinguishes the third from the first two periods in telephone service is a qualitative change in the type of customers to be served. The POTS service lived mostly off residential users, more so in stage one and somewhat less in stage two. This third "information age" transformation. However, rests mostly on business, government, and military users. While the residential market for "wired city" services has been heavily promoted, a prudent skepticism indicates that residential user participation in the sophisticated services which business and government desire will be slow in coming. I have heard mentioned an industry forecast that by the late 1990s as few as 25 percent of residences might be participating significantly in the enhanced services. In light of this fact what will become of universal telephone service? Contributing to the cuteness of the present regulatory problem is the acceleration factor. While the second stage was rather comfortably stretched over a period of some 50 years, we are being rushed through the birth pangs of the third stage very quickly. This means, practically, that somewhere the capital has now to be found to pay for the innovations associated with ISDN.

Who will gain from this wave of innovation? Clearly, the business customers for the enhanced services will gain because they are employing sophisticated communications services profitably in rationalizing their operations (for example, dispatching workers through office automation and robotic factories). Also clearly, the new successors to the old Bell System will prosper, for they are strategically positioned in relation to the government at all levels and to the switched public network—a common resource—so as to take care of their interests effectively.

Who stands to lose from the new order? Again, rather clearly, the nonprofit business subscribers to local telephone exchanges and assorted small businesses, including some independent telephone companies who are less prepared to withstand chronic stagnation than very big organizations. As Basil Hirschfeld's paper indicates, the smaller telephone companies are the ones which will suffer the most in the face absorption by the big ones, now that the Kingsbury Commit-ment and the Bell Memorandum seem to have been cancelled.

The FCC Third Report and Order requires all local operating companies to impose a flat monthly charge per access line of at least $2.00 for residential and $4.00 for business subscribers effective January 1, 1984. It further indicates that over the next five years the minimum access charge will increase annually at 20 percent. If this were a cost-caused increase it would be understandable if not acceptable. There are two other major sources which could be tapped instead of raising this very substantial sum of capital mainly from subscribers. The providers of enhanced services might be assessed a major share of the total enhancement-of-plant
costs. They might pass such assessments on to their business and governmental customers who will benefit most from the enhanced services. The second major source is the telcos themselves: by writing obsolescent plant out of the used-and-useless category and by other actions they could effectively reduce the net burden on subscribers.

But to load this heavy burden on local subscribers seems particularly objectionable, even if it were a cost-caused increase. While it is called an access charge, it really only entitles the subscriber to a dial tone—which he already gets without an access charge. To get this dial tone it is proposed to charge over the next five years a monumentally large monthly fee. Looked at as a means of raising capital, the access charge is a capital levy. It is a tax. As such it is a very regressive tax, bearing relatively more heavily on low income earners than on high, on small businesses more than on large.

The bypass bugaboo is of course closely linked with the drive for flat user access charges. It is hardly possible to take the bypass panic very seriously. Ironically, private line telephone service was established about one year before exchange and message toll service (FCC, Proposed Report, Telephone Investigation, Washington, D.C.: GPO, 1938, p. 416). One might say Bell started with bypass, even before there was a switched network.

The Bell System has from its early days bypassed the switched telephone network in well-known ways. 10.6 percent of its toll service revenues came from bypass service classifications: private line telephone, private line teletypewriter, nurse, other telegraph private line, and radio program transmission.

More recent illustrations of bypass successfully lived with should dispose of the bypass propaganda. Large business and government users have long bypassed the local network with Telepak, CESA, and other special services. Private microwave systems, Western Union, and now specialized microwave and satellite carriers all provide bypass. Television service bypassed the local exchange for good economic reasons, and subscribers should be thankful it did.

One of the greatest problems in telecommunications regulation in the past decade has been the demands of the specialized carriers for interconnection to the local exchange. Resistance to interconnection by the telcos has encouraged them to bypass.

No one seems to be much concerned about the bypass which subscribers will effect by cancelling their telephone subscriptions if flat access charges are enforced and going to other means of communication. Logically, in this situation we may expect to see stand-alone local exchanges being built in reality—not only in theory.

A study by Melody of C&P's experience led him to this conclusion:

The economic test for bypass of C&P's local exchange facilities is whether C&P's private line and special switching services have their rates set to cover their costs. If they do, then bypass should occur only when it is more efficient to do so. If rates substantially exceed costs, uneconomic bypass will be encouraged. If rates are below cost, use of the local exchange will be stimulated for usage that would be more efficiently supplied if it did bypass the system. This inefficient use of the local exchange then must be subsidized by other services.

Results from the 1982 EDA and exchange cost studies show that local channel service, interstate private line, Centrex and other business terminal equipment are all priced below their respective direct costs. This indicates that efficiency would be served if C&P raised these rates and more bypass was encouraged (C&P testimony, October 1985, p. 36).

Bypass a serious problem? Let us be serious. At best it is the old "cream-skimming" argument revived.
EMPIRICAL ESTIMATES OF DEMAND AND COST ELASTICITIES OF LOCAL TELEPHONE SERVICE

A. Noel Doherty

As a result of the FCC's Computer Inquiry IJ decision, the modified consent decree, growth in competition, and technological advancement, the market environment for the telecommunication services offered by a local exchange telephone company has been radically changed.

The purpose of this paper is to present an overview and cost relationships in our new markets. This paper particularly addresses the application of these models to the determination of what changes in tariff levels are needed to achieve revenue requirements. The exposition emphasizes general considerations and reports current results.

The econometric study focuses on intralATA (that is, local) telecommunications revenue, demand, and cost interrelationships. The information derived from this study, namely, price and cost elasticities, enables NYN to determine the final revenue effect from proposed changes in rates. A three-step methodology is discussed. First, a disaggregated forecast is made of revenues in the rate year (a forward looking test period) at the prevailing tariffs. Statistical trending forecasting methods are used; as a check on the reasonableness of this forecast, an aggregate econometric revenue model forecast is developed. Second, demand reactions to proposed tariff changes are estimated; the empirical estimates of own-price, complementary cross-price, and substitute cross-price elasticities are presented. Third, cost changes from
price-induced demand changes are estimated from econometric models. Finally, the last section provides an example of an application in which demand and cost elasticities become an integral part in evaluating the net revenue effect of proposed tariff changes.

Revenue Forecast Methodology

Specification of the Forecast Model

The general functional form of the econometric revenue forecast model is: \( Q = f(P, W, I, T, e) \). This means that the demand for intrALATA telephone service \( Q \) is a function of the real (deflated) price of that service \( P \); the level of employment in New York State \( W \); a trend factor to account for autonomous growth stimuli \( I \); and an error term \( e \) representing the net effect of all other insignificant or non-systematic (random) causes of variation in demand. The prices of other goods and services are explicitly accounted for in the model in that telephone price is deflated by the Consumer Price Index for the New York Metropolitan Area. The trend term performs several functions in the model. One of the more important is to explain the systematic portion of the growth rate in telephone demand that could not be explained by movements in the explanatory economic variables (past, employment and prices). The growth in demand that is measured by the trend term is referred to as autonomous growth and is caused by such factors as marketing activities, new product or service development, and shifts in customer tastes and preferences.

Evaluating the Model's Forecasting Ability

Several approaches are used by forecasters and econometricians to determine the reliability of a model for forecasting (as opposed to evaluating the reliability of a particular parameter of a model, such as the price elasticity coefficient). The first step is referred to as ex post simulation or "backward casting." In an ex post or historical simulation, the model is truncated by eliminating the latter periods of data. The model is then reestimated over the shortened sample period to determine new estimates for the regression coefficients. The truncated equation is then used to forecast the values of the dependent variable for that part of the historical sample period eliminated. Thus, in the ex post simulation, known values of the explanatory (independent) variables are used to make a forecast that can be verified against what has already occurred. In essence, this is a forecast after the fact. In actual or ex ante forecasting, the values of the explanatory variables are, of course, not known and must be predicted. (Indeed, to make the prediction suitable for the purpose of this model, not only must it relate to the overall ex ante forecast period, but also there must be a separate prediction for each quarter of that period.) Only when a forecaster is satisfied with the behavior of the model in the ex post simulation period will he or she venture to apply the model to actual forecasting.

Ex Post Simulation Procedure

The sample period for the revenue forecasting model is from the first quarter of 1973 to the fourth quarter of 1982. The ex post simulation is based upon the most recent eight quarters of data, that is, from the first quarter of 1981 to the fourth quarter of 1982. The ex post simulation procedure may be summarized as follows. First, the sample period is truncated to the end of the fourth quarter of 1980. Second, new regression coefficients are then estimated for the truncated sample period using the same variable specifications used in the full sample period. Finally, using known values of the explanatory variables, forecasts of demand are made for the subsequent eight quarters. The use of an eight-quarter ex post evaluation period is consistent with the objectives of using the model to forecast eight or nine quarters into the future. Figure 1 shows the actual and predicted values of demand (deflated revenue) for the ex post simulation period. It can be seen that the actual and predicted values are close to each other. The model's average ex post prediction error is virtually zero (.003 percent). The average absolute ex post prediction error (that is, ignoring the plus or minus signs of the forecast error) is .53 percent. Other evaluative forecast measurements are also used. Henri Theil has suggested that a forecast may be more properly evaluated by calculating a U-statistic and decomposing it into three terms: (1) a bias proportion, (2) a regression proportion, and (3) a disturbance proportion. The results of these tests are shown in Table 1.

Ex Ante Forecasts

Reviewing the accuracy of revenue forecasts actually submitted in past rate cases is another indication that the overall methodology produces reasonable and consistent results over time. Table 2 summarizes the track record of these forecasts. It presents the average forecasting error over an ex ante period extending between eight and eleven quarters. The total cumulative forecast error is -.14 percent, which represents a slight overestimate of revenues for a five-year period ending in the first quarter of 1983.
Demand and Cost Elasticities

Table 2. Average Forecast Errors of Past Revenue Forecasts Models

<table>
<thead>
<tr>
<th>Period of the Forecast</th>
<th>Average % error</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Quarter 1978 - Fourth Quarter 1979</td>
<td>(.27%)</td>
</tr>
<tr>
<td>Fourth Quarter 1978 - Third Quarter 1980</td>
<td>.01%</td>
</tr>
<tr>
<td>First Quarter 1980 - Fourth Quarter 1981</td>
<td>(.04%)</td>
</tr>
<tr>
<td>First Quarter 1981 - First Quarter 1983</td>
<td>(.04%)</td>
</tr>
<tr>
<td>First Quarter 1982 - First Quarter 1983</td>
<td>(.45%)</td>
</tr>
<tr>
<td>Average Percentage Error 1978-1983</td>
<td>(.14%)</td>
</tr>
</tbody>
</table>

Note: ( ) denotes overforecast.

Price Elasticity Methodology

The concept of price elasticity may be best understood by considering it from two related points of view. In the first instance, price elasticity is a relative measure of the consumer's (or market's) demand response to a change in the price of a good or service, other things being held constant. But since revenue may be defined as the product of price times quantity, price elasticity may also be viewed in terms of the relative relationships existing between changes in a firm's revenue and changes in its price. It is this latter view of price elasticity that must be considered in a rate proceeding to determine what level, and structure, of rates is necessary to realize the permitted revenues.

NYT Econometric Model Estimates of Price Elasticity

Two general approaches were used to measure price elasticity. First, an aggregate demand model was constructed to measure the overall effect on telephone demand and, hence, NYT revenues of changes in the level of telephone prices. Second, nineteen disaggregate models were constructed to measure the price elastic effects of changes in the relative price of telephone service in the eleven major areas of telephone service: access, inside wire, nonrecurring charges, private line (PL), supplemental services, additional message units (AMU), intralATA toll service, Wide Area Telecommunic-
Demand and Cost Elasticities

A. Noel Dukert

tions Service (WATS), coin, semicoin access, and directory assistance calling. Each of these restriction models, both aggregate and disaggregate, is based on data series reflecting the services provided in the postvestiture period. Subject to data availability, separate models were developed by type of customer (that is, business or residential).

Demand Model Formulation

In general, the aggregate and the sixteen disaggregate demand restriction models are variants of the exponential demand model:

\[ Q_t = \ln(\ell) \ln P_t + \text{const} + \sum_{i=1}^{16} \beta_i X_{it}, \]

where

- \( Q_t \): quantity, that is, revenue deflated by its respective price index;
- \( P_t \): price of service;
- \( X_{it} \): lagged quantity, used as a proxy for "habit formation" (or inertia) on the part of telephone users;
- \( \ell \): real own price;
- \( \ell_t \): real cross-price (substitutes and/or complements);
- \( Z_t \): represents one or more vectors of explanatory economic variables other than prices;
- \( I \): time trend; and
- \( s(t) \): stochastic disturbance term.

The \( \beta_i \) coefficients, 1 to 4, represent short-run elasticities defined in terms of a calendar quarter. Demand variables are deseasonalized by the Q-11 variant of the Census Method II Seasonal Adjustment Program or by seasonal binary variables. In addition, binary variables are used to account for these circumstances: (1) events of a short-run duration; (2) structural changes; or (3) to correct for obvious outliers in the data.

Determining the Cross-Elastic Components

From the general form of the model, three distinct relationships can exist between telephone demand and prices of the telephone services and equipment. First, quantity restriction or stimulation within a service category results from a change in the price of that service. This is commonly referred to as an own-price effect. Second, quantity restriction and stimulation result from changes in prices of complementary and/or substitute telephone services offered by WATS. Third, cross-elastic effects from other firms in the telecommunications marketplace influence demand.

Determination of the significant components of the complementary and substitute cross-price variables in the disaggregated model begins with a review of theoretical relationships which might exist among telephone services. Figure 2 presents a matrix showing the likely direction of change of quantities (Q) that would result from changes in own- and cross-price terms (P) among business telephone services. These services are: (1) private line (PL), (2) additional message units which are local billable calls (AMU), (3) toll calls (Toll), (4) WATS, (5) business access lines (BA), (6) other complementary service such as terminal equipment (OC), and (7) other substitute services provided in the marketplace (OS). For example, private line quantity (QPL) has an inverse relationship with its own-price term (PPL). It is potentially cross-elastic with four substitute company telephone services: local calling, intraLATA toll, WATS, and business access lines. Price terms of these services are positively related to private line quantity. Finally, prices of other company complementary services such as special

\[
\begin{bmatrix}
Q_{PL} & + & + & + & + & + & + & + \\
Q_{AMU} & + & - & - & - & - & - & - \\
Q_{Toll} & + & + & - & - & - & - & - \\
Q_{WATS} & + & + & + & - & - & - & - \\
Q_{BA} & + & + & + & - & - & - & - \\
Q_{OC} & + & + & + & + & - & - & - \\
Q_{OS} & + & + & + & + & + & - & - \\
\end{bmatrix}
\]

Note: The subscripts OC and OS represent other complementary and other substitute services, respectively.

Figure 2. Theoretical Own-Price and Cross-Price Matrix for Business Telephone Services
data transmission equipment have a negative (inverse) relationship with private line demand. Each relationship was examined to determine whether the prices of these services should be component parts of the complementary and substitute price terms for the disaggregated demand models. The same evaluation was conducted for demand models of residential telephone service.

When the evaluation process is complete, price data for the potentially important cross-elastic components are collected and developed into cross-price indices. It should be emphasized that only the most significant relationships can be measured, although many potential and real cross-elastic influences may exist among telephone services. More will be said about the empirical findings on cross-elastic effects later in this section.

**Empirical Findings**

Table 3 provides the own-price and complementary and substitute cross-price elasticity coefficients for the aggregate and nineteen disaggregate telephone demand models. The elasticities shown in Table 3 are first-year average values. Long-run elasticities in most cases would be greater in absolute terms.

The Appendix contains a summary of the statistical results from these models. The summary provides the short-run or impact own- and cross-price elasticity coefficients, their respective t-statistics, R², and measures that detect the presence of autocorrelation.

**Measurement of Cross-Elastic Effects**

Cross-price elasticities shown in Table 3 represent either single or multiple telephone service components. Figure 3 provides the details about the service components included in each cross-price term that was found to have a measurable and significant effect on demand. For example, the complementary and substitute elasticities for business access are -.045 and +.076, respectively (See Table 3).

From Figure 3 it can be seen that most of the cross-elastic components relate to usage services such as local calling and toll. Moreover, the cross-elastic relationships are not confined to other usage services but include a number of nonusage services such as access, inside wire, and supplemental services.

**An Example of the Price Elasticity Calculation**

The importance of being able to quantify own-price and cross-price revenue effects when telephone prices are changed is demonstrated in Table 4. The table highlights the inter-
### Demand and Cost Elasticities

#### Table 4. Business Segment Example. $100.00 Increase in Private Line Rates

<table>
<thead>
<tr>
<th>Service Category</th>
<th>Absolute Increase</th>
<th>Restriction/ Stimulation</th>
<th>Net Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Business access</td>
<td>-4.10</td>
<td>4.10</td>
<td></td>
</tr>
<tr>
<td>Private line</td>
<td>$100.00</td>
<td>30.80</td>
<td>62.20</td>
</tr>
<tr>
<td>Local calling</td>
<td>-10.10</td>
<td>10.10</td>
<td></td>
</tr>
<tr>
<td>Toll</td>
<td>-4.50</td>
<td>4.50</td>
<td></td>
</tr>
<tr>
<td>WATS</td>
<td>0.00</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$100.00</td>
<td>$12.10</td>
<td>$87.90</td>
</tr>
</tbody>
</table>

Action among the complementary and substitute services when only private line rates are increased, hypothetically, by $100.00. As a result of the higher rate, private line quantity demanded would decline, which would produce a revenue restriction or loss of $30.80. The net revenue increase for the local telephone company is $62.20. However, the increase in private line rates stimulates demand and revenues for the business access, local calling, and toll services. This means that the $30.80 in revenue restriction is offset in part by $18.70 in stimulation. The net revenue effect is almost $60.00, instead of $62.20. Logic suggests that rates would not have to be raised to the full extent indicated by the price elasticity adjustment since cost savings associated with the lower adjusted test year volumes would reduce revenue requirements. Such cost savings may be treated as an offset to the price elasticity adjustment calculation. In the next section, the methodology for identifying and measuring these cost savings will be addressed.

### Cost Offset Methodology

#### General Considerations

Costs are generally classified as variable or fixed. Variable costs usually include payroll and employee expenses, raw materials, certain office supplies, power and fuel charges, and revenue taxes. Fixed costs usually include the implicit cost of equity capital, interest on borrowed funds, property taxes, any form of payments associated with contractual agree-
ments (for example, rents, salaries under contract, and insurance premiums), and depreciation charges. These costs, although complex, can be examined for a business and related to the volume of input and output. The nature of the production function and the resulting shape of the cost curves are determined primarily by the level of technology of the production process adopted and the degree of input divisibility and substitutability. In the short run, once a production process has been adopted, the mix of service inputs is usually controlled by technology and standard operating procedures, and there are limited possibilities for input substitutions. In the long run, the input factor mix can vary by changing the process, but then the input mix becomes fixed again by the technological requirements of the new process. The amounts of switching output, central processors, telephone sets, cable, land, buildings, and labor are not easily substitutable for one another within a given production process. A concept fundamental to any cost analysis is that of marginal cost (MC). MC measures the change in total cost associated with a unit change in output (that is, the first derivative of total cost with respect to quantity, per unit of time). A concept with a definition similar to that of MC is incremental cost. However, incremental cost is defined generally to represent the change in cost associated with a larger than one unit change in quantity over a prescribed period (such as the test year). For a telephone company, the incremental cost of introducing a new electronic switching system (ESS) would be greater than the marginal cost of either one additional toll call with an existing crossbar system or one additional "new" call processed with ESS equipment.

The logic of this elementary theory suggests a degree of simplicity that does not exist. The classification and analysis of cost in real business are very complex. In applied studies, the initial view is often to equate expenses with variable costs and capital costs with fixed costs. All operating expenses are not variable costs, nor are all capital costs fixed costs. Avoidable costs are not just sunk costs. Real, immediate, and long run, these costs are both smooth and continuous. Contractual commitments and the economic lives of plant and equipment expire at irregular intervals, and the sums involved vary widely. For example, even if demand grows at a steady annual rate, the necessary additions to the capital stock (plant and equipment) are not likely to be added piecemeal given the indivisible nature of most capital investments and the economies that can be realized through large purchases and the avoidance of recurring setup costs. The presence of indivisible (and joint) production inputs severely limits the conclusions that can be drawn from the time-invariant cost curves of traditional theory. The concept of "indivisibility" refers to the fact that some units of inputs, such as physical plant, can be used and built only in certain discrete sizes. This means that over certain ranges of output the costs associated with indivisible units will either not vary or vary in smaller proportion to output changes. This aspect of "lumpiness" of inputs is a common phenomenon to utilities. Joint production inputs refer to the fact that the same inputs are used to produce different services (for example, local and toll messages) and also may be used in the production of peak and off-peak services. The avoidable or unavoidable costs of joint inputs cannot be considered separately on a service or period basis. A reduction in only off-peak demand levels will not reduce the costs of inputs that are used to produce both peak and off-peak services. The only cost savings that would be reasonable in this situation would be those associated with "user" costs. That is, to the extent that the actual use of plant results in transaction expenses, then a reduction in only off-peak demand levels would save only these expenses and not capacity related costs.

The General Formulation of Telephone Cost Models

As explained above, in practice the classification and analysis of costs are very complex. The accounting system provides a large number of historical data series for both expenses and investments but gives little information about their variability and the lag response relationship. Moreover, it does not separate cost according to category of service. For the purpose of this study, costs are classified into the two broad categories of operating expenses and capital expenditures.

The components of operating expenses are: (1) maintenance; (2) traffic; (3) commercial and marketing; (4) general office salaries; and (5) other (largely consists of relief and pension benefits, operating rents, and license contracts). Costs that are considered to be common or unallocable are included only in the aggregate operating expense models. Depreciation (or amortization) and obsolescence expenses are implicitly reflected in the capital or investment equations. In economic terms, depreciation refers to the user cost of capital, that is, the wear and tear associated with the use of equipment. Use depreciation enters into the MC calculation only to the extent that it is not restored or prevented by maintenance and mechanical repair. In utility accounting terms, depreciation is identified with the amortization necessary to recover investment over the revenue-producing life of capital. Obsolescence cost refers
to the loss in value of equipment associated with its vintage, that is, a piece of equipment loses economic value simply because it is an older model.

Capital or investment expenditures are disaggregated according to the Telephone Plant Uniform System of Accounts. These accounts distinguish investment according to the following five categories: (1) central office equipment (COE); (2) outside plant (OP); (3) miscellaneous station equipment (MSE); (4) land and buildings (LAB); and (5) general equipment (GE). The latter category includes expenditures on office furniture and equipment, computer and computer auxiliary equipment, automatic message accounting (AMA) equipment, motor vehicles, and work equipment. The construction budget of NNY, which is the primary data source used for the investment equations, further disaggregates investment expenditure according to the purpose of the investment. There are four classifications of investment: growth (G), modernization (M), customer movement (V), and plant replacement (R). These four classifications are in turn disaggregated according to the following two types of usage: local exchange (LX) and long distance, interstate and intrastate (IL).

The Expense Equation Specifications

The major components of output are as follows:

(1) access (Q1);
(2) miscellaneous station equipment, including inside wire and supplemental services (Q2);
(3) additional message units (Q3);
(4) intrastate toll (Q4);
(5) interstate toll (Q6);
(6) intrastate private line and WATS (Q8); and
(7) interstate private line and WATS (Q9).

Hence, total output may be expressed as

\[ Q (\text{total}) = Q1 + Q2 + Q3 + Q4 + Q6 + Q8 + Q9 \]  

and

\[ Q (\text{intrastate}) = Q1 + Q2 + Q3 + Q4 + Q8 . \]  

From Equation (3) it can be seen that five operating expense (or variable cost) equations could be estimated for intrastate expenses. However, an alternative and possibly more efficient statistical and practical specification of the variable cost models would be to disaggregate cost-output relationships according to customer line (CL) and customer usage (CU). By definition,

\[ Q_{CL} = Q1 + Q2 ; \]  

\[ Q_{CU} = Q3 + Q4 + Q8 . \]  

In addition, aggregate expense equations (including and excluding common costs) could be defined as:

\[ Q_{A} = Q1 + Q6 . \]  

Equation set (4-5) is an efficient aggregation procedure for estimating the operating expense-output relationship since the explanatory variables of each subset (for example, the network subcomponents of AMI, tolls, private line, and WATS) would be the same or very similar.

The most important explanatory variable of both the CL and CU models is quantity. In addition, both models include distributed lag specification terms to capture the dynamic nature of cost-quantity relationships, that is, the actual cost-quantity time path. Other explanatory variables are included in the model to control for possible changes in the cost-quantity relationship over time.

In the sample period of the study (1960-1982), four important events or phenomena occurred that must be taken into account (directly or indirectly) in the measurement of cost-output relationships. These are: (1) inflation; (2) capacity shortages and consequent adjustments; (3) advancements in technology; and (4) changes in the level of churn or outward movement (OM) of customer lines and customer stations. The effects of inflation on cost are controlled for by deflating operating expenses by the Gross National Product Deflator (GNP). It may be noted that the coefficient of correlation between the New York Metropolitan Area Consumer Price Index and the GNP is 0.999.

Advancements in technology such as electronic switching systems (ESS), direct distance dialing (DDD), traffic service position system (TSPS), automatic number identification (ANI), and automatic message accounting (AMA) are controlled for either by a time trend variable or an interaction binary slope variable that both tests and measures any changes that may affect the cost-output relationship over the sample period. Thus, we are left with the econometrician's old standby of a time trend to account for technological advancements. The
use of a time trend variable is effective in accounting for changes in technology (and changes in other autonomous factors that might affect the cost function) as long as (1) technological advancements are relatively smooth and continuous over the sample period and (2) the time trend variable is not strongly correlated with the other explanatory variables of the model. As it turns out, the second condition is not satisfied for any of the preferred operating expense models. Thus, dummy interaction terms were used in all the operating cost models to control for technology changes.

Outward movement and churn produce considerable increases in operating expenses that are not directly related to changes in quantity levels. Since the quantity variables used in the customer line expense model do not reflect the costs associated with churn, it is necessary to include in this model a variable that does reflect this activity. The one selected is the ratio of outward movement to total stations in service. This specification reflects both inward and outward movement of customers.

**Functional Form of the Expense Equation Models**

The general functional form of the operating expense equations may be expressed as follows:

$$ C_{it} = a + b_1 Q_{it} + b_2 Z_{it} + \ldots + b_{n} Z_{it} $$

where $C$ represents operating expenses, $Q$ represents quantity, and $Z_{it}$ (i = 1 to n) represents other relevant variables. The subscripts $j$ and $t$ refer to a particular service category and year, respectively. The term $b_{ij}$ represents the form of the distributed lag relationship between cost and output, that is, changes in cost lag changes in demand. For the operating expenses models, the Koyck (or exponentially decaying weights) lag distribution proved to be the best representation based on summary test statistics. The coefficients $a$ and $b_1$ (i = 1 to n) represent the values of the regression parameters. The value of $a$ is generally interpreted as a constant or intercept term, and its value is often suppressed in regression runs of “variable” cost functions. The rationale for suppression is that at zero output levels (that is, at the origin) variable costs equal zero, by definition. However, the criterion adopted for suppressing the intercept in this study is that the value of the intercept must be proven to be statistically insignificant. This criterion is justified for several reasons. First, from the statistical point of view, the value of the intercept term represents the mean value of variables excluded from the equation. Second, the operating expenses used in the study do not fully reflect variable costs in the theoretical economic sense, that is, there are aspects of fixed costs associated with the operating expense allocations. Third, in some model specifications the constant term is used in conjunction with the specification of another term in the model to reflect changes in trend relationships, such as churn and outward movement.

**The Investment Equation Specifications**

The capital stock of a company may be defined as follows:

$$ K_t = K_{t-1} + C_t - PR_t $$

where $K_t$ represents the capital stock in period $t$, $C_t$ represents capital construction expenditures (including replacement expenditures) in period $t$, and $PR_t$ represents plant retirement expenditures in period $t$. From Equation (6) it can be seen that net investment ($J_t$) (that is, additions to the capital stock) for any given period $t$ equals:

$$ J_t = C_t - PR_t $$

The investment cost-output relationship may be expressed as:

$$ J_t = b_0 + b_1 Q_t + b_2 Z_{t1} + \ldots + b_n Z_{tn} $$

where $Q_t$ represents the change in output, the $X_t$ terms represent other relevant variables, and the $Z_{tj}$ (j = 0 to n) terms represent the parameters (or net regression coefficients) of the equation. For Equation (10) it can be seen that, by definition, the value of $b_1$ represents the marginal cost (MC) of investment associated with a change in output, that is, in discrete terms:

$$ b_1 = (K_t - K_{t-1})/Q_t - Q_{t-1} $$

$$ = \Delta K_t/\Delta Q_t $$

The value of $b_1$ may be converted into an annual revenue requirement value by a simple multiplication. Thus,

$$ MC^* = a + b_1 \Delta R $$

where $MC^*$ equals the marginal (or avoidable) cost in terms of annual revenue requirements and $\Delta R$ represents (1) depreciation and amortization (which varies for type of capital), (2) ad valorem taxes, and (3) rate of return, interest,
and taxes (which also vary according to category).

Equation set (8-13) constitutes the generalized form of the investment cost-output methodology. Recalling the more specific breakdowns of the construction budget data discussed above, Equation (9) may be expressed on a more disaggregated basis as:

$$I_x = k_1(k_2(COE) + OP_x + SE_x + k_3(OP)_x) + PR_x,$$

(14)

where $k_1$ represents an overall general expenditure factor, $k_2$ represents the L & B (land and buildings) investment associated with COE, $k_3$ represents the adjustment factor for L & B associated with equipment, and all other variables are as defined above. Investment also may be disaggregated according to the following major categories of service:

$$I_x = I_1(LD) + I_2(LX) + I_3(SE),$$

(15)

where, in terms of output,

$$LD = QA + QAE + QFE;$$

(16)

$$LX = Q1 + Q2 + QFA.$$  

(17)

The relationships postulated in Equation set (15-17) now make it possible to specify capital cost-output models for central office equipment (COE) and outside plant (OP). The costs associated with land and buildings and general equipment may be reflected by the use of a proportionality factor.

The investment data used to quantify the changes in costs were obtained from the annual construction programs (capital additions) which were reduced by annual plant requirements to yield annual net investment additions. These amounts for each class of plant were divided by the appropriate Telephone Plant Index (TPI) to normalize for inflation and multiplied by the current-to-book ratios to yield the annual change in net investment.

To reflect the different cost characteristics of the major areas, two investment models were developed, namely, central office and outside plant. The Almon lag procedure was used to estimate both. These equations include specifications for technology and capacity utilization and pass the standard statistical tests for structural consistency.

The Statistical Finding

Table 5 presents a summary of marginal cost estimates of expense over major service categories and of the two investment categories for short-run, intermediate, and long-run periods. The models were specified so that the estimates of MC represent the amount of cost savings associated with a $1.00 reduction in demand.

The results of the aggregate operating cost models appear in the third and fourth rows of Table 5. The only difference in the results of these models is that, as should be expected, the long-run estimates of MC ($5.77) of model II (which includes common costs) is greater than the long-run estimates of MC ($5.50) of model I (which has no allocation of common costs).

Results from the central office and outside plant models shown in rows 5 and 6 in Table 5 indicate very small first-year estimates of MC. The current results are surprising because the planning horizon for installing new telephone plant and equipment usually extends well beyond the first year. Moreover, results from an earlier study provided no evidence of any first-year effect.

The major data problems associated with the cost offset
models is related to the construction of the nominal net investment series. Net investment is derived by subtracting book retirements from gross additions. The values of book retirements are converted to current dollars by the use of a series of current-to-book (C/B) ratios, which in turn are based on capital equipment price deflators. The use of the C/B ratios may introduce either a negative or a positive bias in the estimation of the marginal cost of investment (MCI).

The possibility of a negative bias results from the fact that the current dollar conversion method may produce values representing reproduction costs rather than replacement costs. Thus, the nominal net investment series may be understated since the currentized value of book retirements may be overstated. As a result, the estimate of MCI may be too small. The extent of the bias is directly related to the growth in technology of capital. This source of bias can be eliminated by either adjusting the C/B ratios for improved technology or accounting for technological change within the specification of the model.

The potential positive bias on the estimate of MCI results from the fact that the C/B ratios are based on embedded investments rather than the units actually retired. (This is equivalent to assuming a uniform age distribution of actual retirements.) To the extent that the average age of actual retirements exceeds the average age of the equipment reported in the account, the use of the C/B ratios tends to understate the current value of retirements. Hence, net investment and cost savings may tend to be overstated. The obvious solution is to construct capital vintage series extending back to original purchase dates. However, this may be a very time-consuming task, assuming all the necessary data are available. For the capital models of this study, it would be necessary to construct 460 separate capital vintage series extending, in some cases, more than 50 years.

The problems associated with the asymmetry of cost-output relationships and joint inputs and indivisibilities have not been resolved in the estimation of the cost offset effects. The solution to these problems may be more easily obtainable through a combination of econometric and engineering cost methodologies.

An Application

Table 6 presents a summary of the revenue restriction, cost offsets, and net revenue effect of a 10 percent across-the-board increase of twenty telephone services. The column headings are as follows.

Total Gross Award. Values represent the revenues from the proposed incremental price change to the customer. In this example, the values reflect a 10 percent change in rates.

Intra-cost offsets. The values represent the cost savings (expense and capital) associated with the values of revenue restriction and stimulation. All of the values are based on the econometric cost offset models described earlier except for coin, directory assistance, and late payment charges. These were estimated independently of the models.

Net Effect. This column contains the net revenue effect on the company of the proposed tariff changes. The values

### Table 6. Summary of NYT Restriction and Cost Offsets for a 10 Percent Across-the-Board Increase

<table>
<thead>
<tr>
<th>Service category</th>
<th>Total gross award</th>
<th>Intra-cost offsets</th>
<th>Net effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residence access</td>
<td>56.2</td>
<td>3.2</td>
<td>0.7</td>
</tr>
<tr>
<td>Business access</td>
<td>19.4</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Residence inside wire</td>
<td>15.2</td>
<td>2.6</td>
<td>0.4</td>
</tr>
<tr>
<td>Business inside wire</td>
<td>12.4</td>
<td>2.6</td>
<td>0.4</td>
</tr>
<tr>
<td>Supplemental services</td>
<td>18.1</td>
<td>5.6</td>
<td>1.2</td>
</tr>
<tr>
<td>Non-recurring charges</td>
<td>16.3</td>
<td>3.1</td>
<td>0.7</td>
</tr>
<tr>
<td>Private line services</td>
<td>31.6</td>
<td>-7.3</td>
<td>-1.5</td>
</tr>
<tr>
<td>Residence AMU</td>
<td>59.2</td>
<td>20.2</td>
<td>4.2</td>
</tr>
<tr>
<td>Business AMU</td>
<td>77.5</td>
<td>17.5</td>
<td>3.7</td>
</tr>
<tr>
<td>Residence INT</td>
<td>20.9</td>
<td>10.6</td>
<td>2.2</td>
</tr>
<tr>
<td>Business INT</td>
<td>16.0</td>
<td>0.4</td>
<td>0.1</td>
</tr>
<tr>
<td>WATS</td>
<td>7.4</td>
<td>-0.4</td>
<td>-0.1</td>
</tr>
<tr>
<td>Semipublic coin access</td>
<td>2.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Directory assistance</td>
<td>9.3</td>
<td>2.6</td>
<td>2.1</td>
</tr>
<tr>
<td>Other exchange</td>
<td>9.6</td>
<td>0.5</td>
<td>0.1</td>
</tr>
<tr>
<td>Misc. prem. expl.</td>
<td>1.8</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Centrex</td>
<td>17.1</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Busy line verification</td>
<td>0.3</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Returned check charge</td>
<td>0.4</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Local coin</td>
<td>12.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>403.2</strong></td>
<td><strong>61.2</strong></td>
<td><strong>14.1</strong></td>
</tr>
</tbody>
</table>
reflect the amount of revenue the company expects to receive as a result of the total gross award after restriction, stimulation, and intracost offsets have been considered.

Table 6 indicates that the overall revenue restriction factor (Net Restriction/Total Gross Award) from a 10 percent across-the-board increase is 18 percent. As would be expected, this restriction factor is a function of both the size and mix of final price changes. In the business access service category, no revenue restriction or cost offset values are shown. This is because the separate influence of own and cross-price effects cancels themselves out. (In this particular instance, the sum of the own and cross-price elasticities in the first year are approximately zero.)

Appendix: Statistical Results

Statistical results are presented for the demand and cost models described previously.

Demand Models

Table A1 highlights key results from an aggregate and nineteen disaggregate demand models. It provides the short-run (impact) price elasticity coefficients, their respective t-statistics, R², and relevant autocorrelation measures. Thirteen models have a Koyck distributed lag specification which provides the mathematical basis for calculating intermediate and long-run elasticities. Lag structures could not be statistically identified for the remaining seven models. As can be seen from the table, the statistical properties of all the models are excellent. The R² values are high, and there is no evidence of autocorrelation. Generally, the t-statistics are significant at a greater than 95 percent level of confidence.

Cost Models

Table A2 provides a summary of the short-run (impact) marginal cost coefficients, t-statistics, R², and Durbin-W statistics for four expense models. The model form for each model is the Koyck distributed lag specification. Table A3 presents summary statistical results on the COE and DP investment models. Both models are also distributed lag specifications. The length of lag for the COE and DP models was found to be nine and eleven years, respectively.

The statistical properties for the expense and investment models are excellent and pass all relevant tests for statistical significance.
### Table A2. Summary of Expense Model Results

<table>
<thead>
<tr>
<th>Service category</th>
<th>MC</th>
<th>t-stat</th>
<th>$r^2$</th>
<th>h-stat</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer line</td>
<td>.07</td>
<td>1.3</td>
<td>.99</td>
<td>-1.1</td>
</tr>
<tr>
<td>Customer usage</td>
<td>.09</td>
<td>2.6</td>
<td>.99</td>
<td>.6</td>
</tr>
<tr>
<td>Aggregate expenses I</td>
<td>.10</td>
<td>2.2</td>
<td>.99</td>
<td>.1</td>
</tr>
<tr>
<td>Aggregate expenses II</td>
<td>.11</td>
<td>2.1</td>
<td>.99</td>
<td>.3</td>
</tr>
</tbody>
</table>

### Table A3. Summary of Capital Model Results

<table>
<thead>
<tr>
<th>Investment category</th>
<th>MC*</th>
<th>t-stat</th>
<th>$r^2$</th>
<th>DW</th>
</tr>
</thead>
<tbody>
<tr>
<td>COE</td>
<td>.26</td>
<td>3.3</td>
<td>.80</td>
<td>2.1</td>
</tr>
<tr>
<td>OP</td>
<td>.14</td>
<td>3.2</td>
<td>.95</td>
<td>2.0</td>
</tr>
</tbody>
</table>

*The marginal cost of investment in terms of dollars of investment expenditures avoided per dollar of restriction.

### Notes


2. From this formulation, the long-term elasticities may be derived from the following expression:

$$E_l(l,r) = B_l(1 - B_l),$$

where $l = 2,3,4$. The average intermediate or first-year value
3. Because of the paucity of existing data, the third effect cannot be explicitly identified. Its effect is measured implicitly in the own-price elasticity coefficient.

4. Telephone output and cost have multidimensional aspects, such as number of customers, volume of calls, duration of call, length of call, and size of area served. To account for these various aspects of service, detailed revenue series have been used as proxies for output. On the limitations of physical output measures, see J. H. Allenman, "The Pricing of Local Telephone Service," Of Special Publication 77-14, U.S. Department of Commerce, 1977.

5. Moreover, this aggregation procedure minimizes any possible concerns about the cost allocations in the NIT Category Cost Study which have been used to assign expenses over the time series employed. Separate equations for each service category were estimated, and the results were found to be consistent with the aggregate estimates.

6. Modifications of the data series to correct or test for the magnitude of the potential bias produced NIT estimates very close to that derived from the unmodified data series.

7. For a review of the traditional approach to theoretical cost estimation issues, see J. Johnston, Statistical Cost Analysis (New York: McGraw Hill, 1960), Chaps. 3 and 6. Alternative approaches to cost (and production) estimation involve the use of the generalized Leontief and translog functions. Both of these approaches rely on duality theory (that is, the satisfaction of correspondence properties between production and cost functions. See R. Shepard, Theory of Cost and Production Functions (Princeton: Princeton University Press, 1970, pp. 139-77.) For an application of the generalized translog estimation method, see D. W. Caves, L. R. Christensen, and J. A. Swenson, "Productivity in U.S. Railroads, 1951-74." Bell Journal of Economics (Spring 1980): 166-81 and sources cited. This approach may prove fruitful for estimating long-run production function properties. However, it is not a viable approach for measuring or tracing cost offset relationships over time. The translog approach is static by construction, and its mathematical elegance does not justify, without challenge, the limiting and constraining assumptions (such as concavity) of duality theory. The approach reported in this paper does permit the estimation of short-run, intermediate, and long-run MC values. The short-run and intermediate estimates of MC are the values necessary to measure "cost offsets."
CONSUMER RESPONSE TO INTERSTATE RATE CHANGES: AN UPDATE

Susan Grove and Scott Stephan

The characteristics of consumer demand for various components of telecommunications service have been actively researched by industry and academic analysts over the last two decades. (See, for example, the comprehensive review by Taylor [13].) This research activity stems in part from the public policy implications of the economic behavior of consumers, but it is also of great interest in the financial, operational, and marketing activities of the firms engaged in the provision of these services. This paper summarizes the results of a disaggregated econometric model which has become an integral part of AT&T Communications' capability to analyze the effects of rate changes on domestic Interstate Message Telecommunications Service (MTS). This model was

Note: The authors wish to recognize the research staff members who have been associated directly with the model: Glen Thompson, Wayne Reserve, Ken Klaefele, Bill Carroll, John Murphy, Louis Scott, Tom Waller, Carlos Candelario, Joe Gatto, and Ed Hollmehl. Special recognition is due to Bob Auray and Steve Varley for their continuing management support and to Harry Kelezian for his professional advice and assistance. The authors accept full responsibility for the content and accuracy of the paper.

Interstate Rate Changes

among the subjects reviewed by Robert Auray at a previous Institute of Public Utilities conference. At that time the model was in an early stage of development, addressing only a single region of the country; now it is nationwide.

Background

The term rate evaluation, as used here, refers to estimating the effects of rate schedule changes on domestic Interstate MTS volumes and revenues. These estimates are required within AT&T Communications for a variety of purposes, including service planning and rate setting, financial planning, construction planning, and, beginning in 1984, access ordering and management. In addition, the Federal Communications Commission's rules of evidence require that in tariff filings AT&T submit estimates of the effect on traffic of tariff changes. Rate evaluation is a process that provides input to all of these areas.

Of course, tariff changes also affect expenses and investment. Thus, AT&T Communications' internal decision making and support for tariff filings include analysis of both revenue and cost effects, each of which is a function of demand effects. However, this paper addresses the rate evaluation process, which produces only the demand and revenue effects.

To support the rate evaluation function, various analytical techniques are employed. However, at the core of the analysis is an economic model of the demand for message telecommunications, and this model is the primary source of information about consumer response to interstate MTS rate changes.

Model Market Segmentation

The economic model used by AT&T Communications is the Rate Evaluation System (RES) model. It is an econometric model that provides a price elasticity set which is used in rate evaluation. The model considers two aspects of the demand for MTS: the volume of messages and the duration of each message, or its length of conversation. The model addresses fifty market segments defined by various call characteristics such as length of haul, type of call, and so forth. This is a key aspect enabling more complete analysis of nonuniform rate changes, that is, those which do not decrease or increase rates proportionately across all segments. In addition, details about specific segment rate change effects such as are required for construction planning can be produced.

The model market segmentation, that is, the set of call characteristics directly modeled, is a function of the rate schedule structure. The current MTS rate schedule has three features. (1) The usage charge consists of an initial period
rate and an overtime period rate for each of nine rate steps, or length of haul groups. The length of each initial period and each overtime period is one minute. (2) The rate period discount structure is as follows:

<table>
<thead>
<tr>
<th>Rate period</th>
<th>Usage charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Weekday, 8 a.m. - 5 p.m.</td>
<td>Full rate</td>
</tr>
<tr>
<td>2. Weekday, 5 p.m. - 11 p.m.</td>
<td>40% discount</td>
</tr>
<tr>
<td>3. All other times</td>
<td>60% discount</td>
</tr>
</tbody>
</table>

(3) The type of call determines the service charge. Customer direct dialed messages require no additional charges. Customer dialed calling card, operator handled, and person-to-person calls involve a service charge in addition to the usage charge.

The rate schedule suggests three dimensions of relevant market segmentation: length of haul, rate period, and type of call. Economic theory suggests that various customer groups may behave differently. In consideration of both of these factors, the RES model segmentation consists of ten sectors in each of five lengths of haul; this is depicted in Figure 1. Historically, the five length of haul groups represent roughly equal shares of the market. In addition, the rate steps within each length of haul group have experienced similar rate activity. Further segmentation within each group is desirable and was initially attempted; however, due primarily to sampling variability in the MTS historical data source, the smaller segments suggested by the rate

<table>
<thead>
<tr>
<th>MILEAGE</th>
<th>300</th>
<th>300 #</th>
<th>500</th>
<th>500 #</th>
<th>700</th>
<th>700 #</th>
<th>900</th>
<th>900 #</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-30</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>31-120</td>
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<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>121-199</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>200-299</td>
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<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
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<td>300+</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

TOTAL: 50 MARKET SEGMENTS

Figure 1. RES Model Market Segmentation

### Interstate Rate Changes

The segmentation by customer, type of call, rate period, and mileage band indicated above defines fifty market segments, which are designated for convenience 1 = 1, ..., 50. Bill-billed interstate MTS demand quantities, specifically messages (MSG) and average revenue per message (ARPY), are collected for each of the lower 48 states and the District of Columbia (cross sections 1 = 1, ..., 49), and currently for the quarters 1973:3-1983:1 (t = 1, ..., 47) from a subsample of the Centralized Message Data System (CMDS). The pooled cross-sectional time series equations for MSG and ARPY are specified as follows.

$$ \text{BC} \left( \frac{\text{MSG}_{i,t}}{\text{PDL}_{i,t}} \right) = a_{i1} + b_{i1} \left( \frac{\text{BC}_{j,t}}{\text{PDL}_{j,t}} \right) + \text{PDL}_{i,t} \left( \frac{\text{PNK}_{i,t}}{\text{PDL}_{j,t}} \right) + \text{PDL}_{j,t} \left( \frac{\text{PSUB}_{j,t}}{\text{PDL}_{j,t}} \right) + \text{PDL}_{j,t} \left( \frac{\text{ECON}_{j,t}}{\text{PDL}_{j,t}} \right) + \text{PNK}_{i,t} \left( \frac{\text{ECON}_{j,t}}{\text{PNK}_{i,t}} \right) + \epsilon_{i,t} $$

(1)
\[
\begin{align*}
\text{BC} \left( \frac{x_{jit}}{h_{j}} \right) & = c_{ij} + d_{ij} \left( \frac{x_{jit}}{h_{j}} \right) + \text{POW}_{jit} \\
& + d_{ij} \left( \frac{x_{jit}}{h_{j}} \right) + \text{POW}_{jit} \\
& + d_{ij} \left( \frac{x_{jit}}{h_{j}} \right) + \text{POW}_{jit} \\
& + W_{jit}, \\
(2)
\end{align*}
\]

The variables in these equations are defined below, and the operators are defined as follows:

\[
\text{BC} \left( \frac{x_{jit}}{h_{j}} \right),
\]

with \( z \) any real number, is the operator performing the Box-Cox transformation, that is,

\[
\frac{\text{BC} \left( x_{jit} \right)}{z} = \left( \frac{x_{jit}^z - 1}{z} \right).
\]

(Note: when \( z = 0 \),

\[
\frac{\text{BC} \left( x_{jit} \right)}{0} = \log x_{jit}.
\]

log is the natural logarithm; when \( z = 1 \), a linear transformation is involved.) Thus, this general Box-Cox specification allows for common functional forms such as log linear, linear, and semi-log as special cases (see the estimation section) and thus time varying elasticities. The operator \( \text{POW} \), with

\[
P_{0i} \left[ x_{jit} \right] = \text{POW}_{jit} + \text{POW}_{j} - \ldots - \text{POW}_{j} - \text{POW}_{i} - 1,
\]

with the \( \text{POW} \) chosen so as to to fit a specified polynomial function of degree \( D \) by conventional techniques in each segment. Note that by writing the \( \text{POW} \) operator in this manner the coefficients \( b_{1j}, \ldots, b_{3j} \), are long-run coefficients (elasticities in the cases \( x_{jit} = h_{j} = 0 \)).

**RES Model Variables**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>MS(_{jit})</td>
<td>the number of Bell-billed interstate MTS messages in segment ( j ), state ( i ), time ( t ) (Source: CMOS);</td>
</tr>
<tr>
<td>OS(_{jit})</td>
<td>the number of telephones connected to the network by Bell access lines for the appropriate customer class in state ( i ), time ( t ) (Source: Bell System Report M77);</td>
</tr>
<tr>
<td>PD(_{jit})</td>
<td>a Laspeyres chain-linked index of the prices of messages in segment ( j ), state ( i ), time ( t ) (Source: AT&amp;T Communications);</td>
</tr>
<tr>
<td>PS(_{jit})</td>
<td>a Laspeyres chain-linked index of the prices for the alternative ways of placing a call to the same place in segment ( j ), state ( i ), time ( t ), that is, by other types of calls, or rate periods, same length of haul? (Source: AT&amp;T Communications);</td>
</tr>
<tr>
<td>ECON(_{jit})</td>
<td>an average measure of economic activity in state ( i ), time ( t ) ( = \frac{PO(<em>{jit})}{PO(</em>{jit})} ) for residence and public segments, and ( EPM(<em>{jit}) ) ( = \frac{D(</em>{jit})}{D(_{jit})} ) for business segments;</td>
</tr>
</tbody>
</table>

I and D any positive integers representing the length of lag and the degree of polynomial, is an operator such that
Variable | Explanation
--- | ---
PDI1t | Disposable Personal Income for state \( j \), time \( t \) (Source: Chase Econometrica-Combination of Department of Commerce, Bureau of Economic Analysis [BEA]; data and IRS Statistics of Income data.)
POP1t | Population aged 16 years and older in state \( j \), time \( t \) (Source: BEA.)
EMP1t | non-agricultural employment in state \( j \), time \( t \) (Source: BEA.)
POH1t | a general price index of all other goods (inputs and outputs) in state \( j \), time \( t \) (Source: CPI for business segments^9).
CP11t | "state specific" consumer price index series constructed from 26 SMSA CPI series for state \( j \), time \( t \) (Source: AT&T Communications and BEA.)
PND1t | GDP price deflator in time \( t \) (Source: BEA.)
AMP1t | REY1t ; MNI1t
REY1t | Bell-billed interstate MTS revenue in segment \( j \), state \( i \), and time \( t \) (Source: CENS.)
PIN1t | a chain-linked Laspeyres index of initial period prices of messages in segment \( j \), state \( i \), time \( t \) (Source: AT&T Communications.)
POV1t | a chain-linked Laspeyres index of overtime period prices for segment \( j \), state \( i \), time \( t \) (Source: AT&T Communications.)
Vt-1 | error terms.

Note: All variables except MTS price variables have been seasonally adjusted by the Shiskin X-11 method.

The particular specification for messages reflects several generalizations, restrictions, or aspects of economic theory which have been found to be of some importance in disaggregate studies of MTS demand. First, the general functional form implied by the Box-Cox transformation of dependent and independent variables allows for a wide range of possible linear and nonlinear demand curves and, as a result, elasticities which are temporally constant or which vary with the levels of prices or income.11 An additional feature is that the equations are dynamic, allowing for a gradual adjustment of demand to changes in the relevant independent variable set. Dynamics are introduced through a polynomial distributed lag, although a number of approaches have been considered and remain a topic of current research.12

Another feature of proven value is the utilization of pooled time series and geographic cross-sectional data to estimate the parameters for each of the fifty market segment equations. Although traditional formal motivations for such pooling would imply an equivalence among the individual cross-sectional coefficients of the independent variables, this is an unnecessarily restrictive view. For example, if the pooling is motivated by a random coefficient regression model, the interpretation of each coefficient in Equation (1) is as the national mean of the individual cross-sectional coefficients.13 Evidence exists which indicates that substantial efficiencies in estimation in the presence of multicollinearity and a modest time series length are produced by pooling for a wide range of cases other than the traditional one of parameter equivalence.14

Monetary variables in the specification are measured in "real" terms by deflation by an index of the prices of other goods and services. This implies that demand is a function of the nominal variables, as indicated in the equations above, as well as of the prices of other goods and services, as required by consumer demand theory.15 This specification of the monetary variables also implies that the theoretical property of the homogeneity of degree zero in prices and income is maintained for the entire class of functional forms implied by the Box-Cox transformations.16

The model is specified in a per household manner analogous with per capita specifications common in demand studies.17 Such a normalized response variable is extremely valuable if pooling is considered in the context of functional forms other than log-linear, since the parameters of other functional forms could be different by cross-section owing simply to the different magnitudes of each cross-section.18 In the context of MTS demand, however, the specification has an additional useful interpretation as a conditional demand curve of a multistage maximization process.19 In this case the necessity of first subscribing to the network (or using a public telephone in the case of coin sent-paid) in order to enter the market for MTS is reflected.20 Both by capturing one important reality of the telecommunications market and
by enabling the simplification of empirical representations of complex demand interrelationships, the specification is extremely valuable.

The ARPM equation is analogous to the message-per-telephone specification both in the need for an appropriate normalization and in its interpretation as the demand for additional minutes in segment $j$, given the initiation of a message in segment $i$. Notice that ARPM, except for a modest degree of aggregation over the RES rate schedule, is determined by the initial and overtime period prices and by the average number of overtime periods per message purchased by consumers in segment $j$. Thus, if the average number of overtime minutes purchased is a function of MTS prices, other prices, and average economic activity, the general specification in Equation (2) is suggested. The motivation can be taken as a continuation of the multistage maximization process described previously. Consumers first decide upon access, next they choose among the segments, that is, alternative ways to place a message; then, having placed a message in the $k$th segment, consumers choose the number of additional overtime minutes to purchase. The advantages of this specification over one involving aggregate minutes (or revenues, or a revenue-based quantity index) are related to prior expectations that consumers may behave differently in adjusting the number of messages (frequency of calling) versus adjusting the average length of each call. This is suggested, at least stylistically, by the relative stability of average length of conversation compared to message volumes.

The specification of the error term follows that suggested by Kearta [10], allowing for unique first-order autocorrelation in both cross-section and heteroscedasticity. Dependence between the cross-sections (dependence of course, however, the number of cross-sections (49) exceeds the number of time points.

Initially and over the course of the model's continuing development, variables other than those listed above have been considered. However, the variables listed are deemed the most important—both from the viewpoint of degree of explanation, statistical significance, and economic reasonableness and from the viewpoint of the objectives and measures sought from the model. Most important, perhaps, are the basic properties of the model and its general results have exhibited a remarkable degree of stability to variations in the variable list. To a minor doubling of the length of the time series, since the 1978 prototype, and to variations in the specification of dynamic processes and specification of error terms.

**Estimation of the Model**

The estimation of the pooled equations is by a multistage generalized least-squares incorporating estimation

of the polynomial distributed lag. In addition, further pooling of information across the segments is entertained in the message per telephone equations by incorporating a common nonlinear parameter across all segments to aid in the estimation of the substitution effects. While a detailed discussion of these additional complexities is beyond the scope of this paper, the additional restrictions are generally accepted by tests, and they also contribute to assuring that a set of discrete equations implies theoretically plausible behavior for the various aggregate economic goods which can be defined from this set of discrete equations.

Prior to the estimation of these pooled equations, approximate maximum likelihood techniques are used to determine the appropriate Box-Cox transformation parameters. As this is a nonlinear procedure and implies a relatively high degree of computational burden for a model of this size, early research concentrated on evaluating a broad range of the admissible parameter space for $j$, around 0. These investigations gave a good indication of the general regions of the likelihood function yielding the maximum and the degree of sensitivity of the coefficients to choice of the parameters. This portion of the parameter space was then partitioned into discrete points to yield three functional forms which are readily interpretable as common functional forms in use by econometricians, namely, the log linear, semilog, and linear. For regular update and model maintenance purposes, this subset of the parameter space is examined, and a preferred functional form is selected for each message per telephone and ARPM equation for each market segment. As computational processes improve and costs decline, and as the range of issues addressed by the Box-Cox transformation increases, it is anticipated that a more continuous examination of the parameter space will be utilized, including different transformation parameters for different right-hand variables.

Also prior to the estimation of the pooled equations, attempts are made to identify specifications for the POL in terms of length of lag, degree of the polynomial, and end-point restrictions which yield "plausible" adjustment processes from a theoretical point of view. In practice, this leads to considerations of continuity, single turning points, monotonically declining coefficient magnitudes, and non-zero restrictions. The manner in which fitted adjustment is introduced is an area of continuing investigation from the point of view of both economic theory and statistical technique.

Even given the structure described above, the RES model is of formidable size. The model is estimated using 220,000 (quarterly, cross-sectional) message and revenue observations constructed by processing more than 200 million subsampled CMRS record observations. In addition, 217 telephone, economic, and demographic time series are involved, as well
as almost 10,000 unique MIS price index series for own-, cross-, initial, and overtime period prices. These data are used to estimate 486 current and lagged price coefficients, 290 current and lagged economic activity coefficients, 400 functional form parameters, and almost 15,000 "nuisance" parameters, including elements of the disturbance variance-covariance matrices and individual cross-sectional constant terms. Researchers may disagree as to whether the model could be improved by further disaggregation or aggregation. Nonetheless, the RES model has proven a workable compromise between the conflicting issues of cost, simplicity of structure, stability of results, sampling variation, and the statistical and economic implications of the results.

The interval of estimation, the third quarter of 1971 through the first quarter of 1983, involves a substantial range of rate activity, including seven rate changes, as shown below.

<table>
<thead>
<tr>
<th>Date</th>
<th>Rate Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/22/73</td>
<td>Nonuniform changes</td>
</tr>
<tr>
<td>3/30/75</td>
<td>Restructure</td>
</tr>
<tr>
<td>2/19/76</td>
<td>Discount structure introduced</td>
</tr>
<tr>
<td>9/13/77</td>
<td>Nonuniform changes</td>
</tr>
<tr>
<td>6/08/80</td>
<td>Small overtime period rate changes</td>
</tr>
<tr>
<td>6/20/81</td>
<td>+5% change</td>
</tr>
<tr>
<td>4/02/82</td>
<td>Restructure</td>
</tr>
<tr>
<td></td>
<td>Calling card rates introduced</td>
</tr>
<tr>
<td></td>
<td>Direct dial: -5% to +5%</td>
</tr>
</tbody>
</table>

Of particular note is the restructuring which occurred in the mid-1970s. A uniform discount structure was introduced producing relative price variation across rate periods. Along with the restructuring, the usage charge changes for direct dialed messages varied from increases of up to 30 percent to decreases of equal magnitude. In addition to the range of rate activity, the rate changes have been distributed throughout the estimation period and have occurred during various kinds of economic conditions. Thus, the interval contains a rich rate experience on which to base estimates of model parameters, particularly price elasticities.

As mentioned previously, model estimation produces several thousand parameter estimates and measures of statistical significance. To aid in summarizing these results, the aggregate "net elasticity," which is a combination of own- and cross-price elasticities is summarized. Net elasticity measures the demand effect of a uniform rate change (see note 28 also). The empirical results of the RES model suggest that the overall

MIS market is inelastic with respect to rate changes. The last three estimations of the model (in each case, at least four additional quarters of historical data were available) produced aggregate long-run elasticity estimates in the range -.65 to -.70, indicating a high degree of stability in the model. With respect to statistical significance, of the 195 long-run price coefficients, 182 have the expected sign, and of those 174 are significant (at the 5 percent level). Overall, in each of the 100 equations, the F-statistic is well above the critical value. Details about the model estimation are contained in the Appendix.

Conclusion

The RES model has provided substantial empirical information about MIS consumers, and this information has proven valuable in planning at AT&T over the past few years. The research associated with the model has been extensive but certainly is not at an end. Ongoing efforts address the continuing need for more complete understanding of the dynamics and interrelationships of various market segments. In addition, the changing structure of the industry requires investigation of new specifications and segmentation. Perhaps, therefore, the current RES model is itself only a prototype for another, as yet undefined, more comprehensive model of MIS.

Notes

1. See Auray [2].
2. As used here, "domestic Interstate Message Telecommunications Service (MIS) means telephone calls subject to FCC Schedule 1 rates. This includes calls between states within the contiguous United States, but does not include calls provided by MTS, private line services, or by other common carriers. For a more comprehensive definition see Auray [2, p. 76].
3. Description of the types of analysis and the analytical system utilized in studying the firm's rate of return is contained in theTariff Setting Practices filed by AT&T Communications with the FCC.
4. The CMS system has as a sample universe all messages transmitted over the Bell-owned network. On a regional basis, data from independents were not included in the referenced subsample until the middle of 1977 and generally do not include detailed customer class information. As a result, only Bell-titled message data were...
used in the model. The standard monthly sample of 5 percent also did not necessarily include customer class
information prior to 1977; the smaller subsample was
able to be manually supplemented to make up for the
excluded information. As is the subsample (effectively
a 0.5 percent sample) provides a relatively low cost
source of regional, customer-detailed, Bell-operated infor-
mation from the third quarter of 1971 to the present.

5. This is essentially a count of telephones in service
on Bell access lines. For residence, it is simply a
count of the number of access lines, while for business
it is a measure of total business telephones.

6. See Auray [2, p. 75], in particular footnote [e].

7. In the course of research it connection with the RES
model, there has been extensive work with methods of
measuring these substitution effects. These have ranged
from including each individual cross-price and imposing
Liebacy symmetry, to including various types of aggregate
cross-price indices reflecting other types of call and/or
other rate periods. Multicollinearity has been a persist-
tent problem, and while the results have been generally
successful in that there are findings of significant
substitution, there have been problems in elaborating
cross-substitution effects in specific cases, such as
rate period cross-effects in residence segments. Current
research in this area has been very promising in combining
the approaches described above with a random parameter
model. This has allowed equations to be specified more
generally in terms of economic theory, yet with substan-
tial reduction in the number of free parameters.

8. There have been various choices for the economic variable,
particularly for the business equations, since at the
regional level there is no single measure capturing
total output. Nonetheless, the choice of the economic
variable has not greatly affected the results for the others
coefficients of the model.

9. The choice of deflators for the model involves a number
of trade-offs such as the availability of regional series,
what prices are included in the index, how interest
rates are reflected, and so forth. In the residence equa-
tions, the intent is to measure a weighted average of
consumer prices, while in the business equations a broader
measure of all output prices is desired. Alternatives,
such as the national deflator for personal consumption
expenditures, as well as different ways of computing the
costs and the regional series, have been tried without
substantial variation in the estimated price coefficients.

10. These indices are created on a state-specific basis
by mapping and/or weighting the available Standard
Metropolitan Statistical Area (SMSA) CPI indices in
a different manner for each state. For example, for
Pennsylvania, the index is an SMSA expenditure weighted
index of the Pittsburgh and Philadelphia SMSAs. For
states without an included SMSA, the index for an SMSA
in the same region is selected. The approach is simply
an attempt to reflect as much regional information as
is readily available.

11. The Box-Cox transformation yields a variety of functional
forms (see Kenete [10, pp. 467-68] and TFP 1303 [16,
pp. 442-447]), and regressions of this type may be solved by
maximum likelihood methods. Note that the elasticity
at time $t$ for cross-section $i$ is given by

$$E_i = \frac{\lambda_i + \theta_i}{\lambda_i + \theta_i}$$

in a Box-Cox function of the form

$$\lambda_i \left( \frac{y_i}{i^{1/2 \lambda_i}} - \frac{1}{\lambda_i} \right) = a_i + \beta_i \left( \frac{y_i}{i^{1/2 \lambda_i}} - 1 \right) / \lambda_i$$

12. See, for example, Doherly [4], Almon [1], Johnston [7],
and TFP 1303 [16]. Research with the RES model has
explored a number of approaches to the manner of intro-
ducing dynamics. The standard Kydck approach relates
additional equations in the context of pooled cross-
sectional models. Given the range of other issues
addressed in RES, and given that the model represents the
demand for a marketable good, there has been a prefer-
tence for approaches to the dynamics problem defined
in terms of exogenous variables with relatively short
lengths of lag. This is roughly consistent with the
empirical evidence as well (see Taylor [13], Houthakker
and Taylor [8], and Keiley and Murphy [8]).

13. The pooled equations could be taken as fixed effects
models, that is, hypothesizing parameter equivalence
across all cross-sections. However, models based on
random parameters could motivate such a pooled model
by assuming different coefficients "drawn" from a distri-
bution with common mean and finite variance. Such assump-
tions would yield a pooled model and the interpretation
that the parameters of the pooled equation are the
national means. (See Swamy [12], Keiley and Stephan
[8], and TFP 1303 [16, Appendix 2].) An additional
feature of the generalization of the fixed effects pooled
model is the ability to generate predictions of the individual state coefficients in a more efficient manner than the corresponding single equation or seemingly unrelated regression approaches.

14. See Kolodziej and Stephan [9].

15. Any demand function specified in terms of "real" variables or ratios between monetary variables, that is, \( d_1 = f_1(p_1/p_2, q_1) \) or \( d_2 = f_2(p_2/p_3, q_2) \), automatically exhibits homogeneity of degree zero in the prices \( p_1, p_2, \) and \( p_3, \) and income \( Y \) (see Phillips [11, pp. 69-72]). Furthermore, it would not be correct to expect in log-linear versions of Equation (1) that \( b_1 + b_2 + b_3 = 0, \) due to homogeneity of degree zero.

(See Section II, pp. 13b-7 regarding the divergence of net price elasticities from corresponding income elasticities.) In fact, \( b_2 = b_3 = 0 \), where \( b_2 \) is the implied cross-price elasticity of good \( q_2 \) with respect to all other prices (that is, as measured by CPI in the residence equations) because homogeneity of degree zero has already been ensured by the use of real variables. Homogeneity of degree zero could be imposed in the long or the short run depending on the type of dynamic model adopted. Note, for example, that a single adjustment parameter Keyce scheme implies homogeneity in the short and long run (using real variables). Experimentation with imposing homogeneity only in the long run has been done, but it did not affect the estimated price elasticities substantially.

16. The variables are in real terms before the transformation is applied. This avoids the difficulty of considering functional forms which would not even admit of homogeneity of degree zero. For example, a linear function in nominal prices and income would only admit of homogeneity of degree zero if demand were a constant and independent of prices and income (see Phillips [11]). Thus, real variables limit choices to those curves which may at least serve as approximations to demand curves.

17. The per capita or per household (with per capita or per household income) specification is very common in applied demand studies (see Houthakker and Taylor [6]). The implication of a per capita model is somewhat more general than that of a model with aggregate demand as a function of aggregate income. The former allows for a proportionate effect of population and a general effect for per capita income; thus the effect of a change in aggregate income (that is, in a log-linear per capita specification) varies depending upon the relative growth of population versus the average income per person. This may be contrasted with the corresponding (log-linear) model for aggregate demand which implies the same effect of an increase in aggregate income whether made up entirely of a change in per capita income or entirely of a change in population. Of course, a model with both variables free on the right-hand side is more general yet, but it may unnecessarily complicate the multicollinearity problem, particularly if there are reasons to expect roughly a proportionate effect of population. Examples would be the case of the convergence approach to the aggregation problem (Thiel [14]), or telephone subscription when there are no access externalities (see note 20).

18. In specifications other than the log-linear model, the coefficients are unit of measure dependent. Thus the state coefficients vary simply as the size of the dependent and independent variables unless they have been normalized in some way (that is, messages per telephone and income per capita). In a pooling model, benefit is derived by eliminating this large source of unnecessary variation in the order of magnitude of the individual state parameters.

19. As an example, consider a consumer's utility maximization for the set of \( n \) goods divided between the subsets, \( A \) and \( B \) (the latter a "preallocated" set). The consumer maximizes a utility function, \( U = f(x_1, \ldots, x_n) \), subject to \( p_1 x_1 = e_1 \) and \( p_2 x_2 = e_2 \) for \( i = 1 \). Then the conditional demand curve for the \( i \)th good is \( x_i = g_i (p_1, x_2, e_2) \). The conditional demand curve is a function of only the prices of the unallocated goods, income not spent on preallocated goods, and the amount of preallocated goods. See Phillips [11, pp. 72-78] and note 20. Note that if the amounts of preallocated goods coincide with the quantities associated with the unconstrained maximization of \( U \) then these conditional demand curves are an equivalent representation of the unconditional demand curve (that is, demand curves in all prices and income).

20. In the case of message demand, the conditional demand curves represent the "technological" necessity of first being "on the network" in order to place a call. For an individual consumer \( j \), the demand for messages might be represented in the notation of note 19 as \( N_j = f(j, p_1, x_2, e_2) \), where messages and other goods and services are elements of \( A \), \( j = 1 \) when the \( j \)th consumer subscribes to the network, and \( j = 0 \) when
the jth consumer does not subscribe. The decision to subscribe belongs to the set \( \delta \) in the notation of note 15. For examples of these kinds of models see Taylor [13]. (Notice that absent the access externality there would be a number of models which would lead to the expectation of a proportional effect of billed subscribers. The RES model represents interstate messages; thus, in Taylor's sense, the access externality would be measured by subscription outside the particular state. Earlier work on the RES model, with shorter time series, attempted to include all such variables but was not successful at measuring a significant effect. With the longer time series now available, this approach is of growing interest.) Considering the simple conditional form above in the aggregate for all consumers, \( \sum_{j} T_{ij} = \frac{1}{T_{ij}} \frac{1}{T_{ij}} \sum_{j} (P_{ij} - \bar{P}) \), and following Thiel's convergence approach (for stable income distribution and/or uncorrelated income coefficients; see Thiel [14, pg. 570-72]), if \( \frac{\sum_{j} f_{ij} (P_{ij} - \bar{P})}{\sum_{j} f_{ij}} / \frac{\sum_{j} f_{ij}}{\sum_{j} f_{ij}} = E \), where \( E \) is mathematical expectation and \( \bar{P} \) is the mean of the conditionalized income distribution. As a practical matter, the proportion of income devoted to subscription would tend to be small for subscribers; this would justify using total income in empirical applications.

21. In the case of ARPM, the "technological" limitation is that messages must first be purchased in a segment before overtime minutes in that segment are consumed. In addition, the consumer must decide prior to purchase of the overtime minutes what segment the call will be placed in without knowing exactly the length of conversation (LOC) of the planned call. (In general, the relative price between calls in different segments is a function of the LOC.)

22. Note that ARPM is not a price measure but is a function of the tariffed initial and overtime period prices and the number of overtime minutes per message consumed. Thus, ARPM is a "price" only for fixed lengths of conversation. ARPM can be expressed as a product of current weight divisia price and quantity indices. Abstracting initially from aggregations of the rate schedule, \( \text{ARPM}_{ij} = \frac{(OP_{ij} \times \text{OV}_{ij})}{\text{IP}_{ij} \times \text{MS}_{ij}} \), where \( \text{IP}_{ij} \) and \( \text{OP}_{ij} \) are the initial and overtime period rates, respectively, and \( \text{OV}_{ij} \) is the number of overtime minutes in segment \( i \). The Total differential of this identity is of the form:

\[
\frac{d \log (\text{ARPM}_{ij})}{d \log \text{IP}_{ij}} + \frac{d \log (\text{ARPM}_{ij})}{d \log \text{OP}_{ij}} + \frac{d \log (\text{ARPM}_{ij})}{d \log \text{OV}_{ij}}
\]
26. These types of nonlinear restrictions affect the model equations which include an explicit MTS cross-price variable, namely, the business and residence message per telephone equations of the type shown as Equation (1) previously. Consider grouping these equations in nine groups of five each so that within each group the customer class, type of call, and rate period are the same. Each group will then contain the equations for the five all-price bands. For convenience of notation consider that the equations \( i = 1, \ldots, 5 \) constitute such a group, and define the nonlinear parameter \( \gamma = \beta_{22}/\beta_{31} \). For additional ease of exposition, case the rate in which all equations in the group are log-linear; then a given \( \gamma \) is the ratio between the long-run cross-price elasticity and the long-run own-price elasticity. This nonlinear parameter is extremely useful since (1) it is a priori considerations lead us to expect a narrow range for this parameter and (2) it suggests an extended type of pooling within the above defined groups which is considerably more general than restricting all the parameters within each group.

A priori considerations lead to the expectation that the rate period and type of dimensions of MTS message segmentation constitute a group of substitutes and (given the small budget shares represented by MTS goods) that \( \beta_{22} > 0 \). If the goods are normal (or non-different), then \( \gamma \) would be expected to be \( \gamma > 0 \) and thus \( \gamma > 0 \). Other theoretical considerations relating to the relationship of MTS to all other goods, and the requirement that disaggregate equations should imply reasonable theoretical properties for the prices of aggregate goods which could be defined (see note 26), imply that \( \gamma < 1 \). For equations within a group in which customers face essentially the same type of trade-offs of type of call and rate period, this suggests the possible restriction \( \gamma_i = \gamma_j = \gamma_2 = \ldots = \gamma_5 \) which pools the relative price variation between the mileage bands, yet is very general in the sense that each segment is specified with a different own- and cross-price elasticity. This is particularly important because in some mileage bands the relative price variation has been quite substantial, while in others it has been quite modest.

The parameter \( \gamma \) can be related to the elasticity of substitution between the \( i \)th good and the remaining substitute goods. Research into methods which balance the economic generality of the models with the need for parameter parsimony is ongoing. Furthermore, generalizations on this method, which incorporates the symmetry restrictions via random parameters, identify more specific cross-elasticity elements and seem quite promising. (See note 7; see TFP 1303 [16] for more details.)

27. Unrestricted estimation of these nonlinear parameters yielded a distribution with the bulk in the admissible range (see note 26). Individual estimates had a higher probability of lying outside the admissible region of multicollinearity was particularly high, or if it was a particularly sparse market segment in terms of the number of sampled records. Also, there was a tendency for the unrestricted estimates to be more homogeneous within the nine groupings than among them. Joint likelihood tests of the restrictions for the whole model are generally accepted; however, some specific segments yield poorer solutions, and one short haul business segment fails the test. The general procedure is to accept the test evidence for the model as a whole, impose the bounds solutions when necessary, and in one case free the individual parameters when indicated by tests and not yielding results outside the admissible range.

28. The lower bound on the \( \gamma_j \) of minus one, stated in note 26, is implied by two considerations: (1) the expected relationship of MTS goods with respect to all other goods in terms of compensated cross-elasticities, and (2) the expected restrictions on (for what hereinafter are termed) the net elasticities for each of the various segments, stemming from the theoretical restrictions on the parameters of the various aggregate goods which can be defined for MTS goods.

In a given message per telephone equation of the type shown as Equation (1) previously, and for ease of exposition considering only the log-linear functional form, the implied long-run cross-elasticity with respect to all other (non-MTS) prices (denoted here by \( \phi_{ij} = \beta_{ij}/\beta_{ij} \) ) is derivable from the homogeneity of degree zero restriction. (See Henderson and Quandt [5].) Define the net elasticity (the elasticity with respect to a proportionate change in all MTS prices) as \( \tilde{\phi}_{ij} = 1 - \phi_{ij} \). Mula [15] defines this as the elasticity with respect to a proportionate change in the prices of a subset of all goods. Then \( \phi_{ij} = -E_j b_j \).

The Slutsky decomposition implies \( \phi_{ij} = \phi_{ij}^{*} - N\phi_{ij} \), where \( \phi_{ij}^{*} \) is the compensated cross-elasticity of MTS good \( j \) with respect to the price of non-MTS goods, and \( N \) is the budget share of expenditures on non-MTS goods. As \( \phi_{ij}^{*} \) in this case is very close to one, this implies that \( \phi_{ij} = -E_j b_j \); that is, the compensated cross-elasticity of the \( i \)th good with respect to the prices of other goods is approximately the same magnitude and opposite in sign to the net elasticity of that good. A negative net elasticity would then imply that all other goods are substitutes, although one might tend to interpret this as "gross" substitutes in the sense that all other...
goods compete for the consumer's dollar (see Philips [11]).

The concept of net elasticity is relevant in considering various types of aggregate MTS goods which can be defined from disaggregate MTS goods. Wold [15] argues that an economic aggregate good can be defined from any set of disaggregate goods by considering what happens to the sum of the disaggregate goods given a proportionate change in the prices of all the disaggregate goods. Wold further argues that for such a definition of the aggregate good, all the restrictions of consumer demand theory also apply to the aggregate good (negative own-price elasticity for normal goods, positive income elasticities for normal goods, and so forth). Furthermore, the own-price elasticity for the aggregate good MTS (abstracting from the ARPM equations) would be given by $\gamma_j = \bar{E}_j$, where $E_j$ is the net elasticity defined above and the $\alpha_j$ are the (positive) expenditure proportions on the disaggregate MTS goods, such that $\sum\alpha_j = 1$. A sufficient condition that the own-price elasticity of the aggregate good be negative is for the net elasticity in each segment $j$ to be negative.

Both of the considerations above suggest that an expectation of a negative value for the net elasticity in each segment is not unreasonable. In terms of the nonlinear parameters introduced in note 26, the net elasticity may be expressed as $\bar{E}_j = \bar{E}_j(\lambda_j, \gamma_j, \lambda_j, \gamma_j)$. If the own-price elasticity $\lambda_j = 0$, then $\gamma_j = 1$.

29. Initially, the RES model was considered in log-linear form ($\lambda_j = 0$, $\gamma_j = 0$ for all $j$), and when the Box-Cox transformations were introduced the entire likelihood function was examined for a wide range of parameters around the zero origin. As it turned out, the likelihood function is characterized by a considerable plateau in the region defined by $1 - \lambda_j = 0$, $1 + \lambda_j > 0$, and quite reasonable stability in terms of the average elasticities in that region. This seems reasonable given that the parameters $\lambda_j$ and $\gamma_j$ may be thought of as describing the rate of change of the elasticity with respect to changes in the variables, with the zero values associated with constant elasticities.

30. Since for regular update and maintenance purposes the continuous Box-Cox approach described in note 29 is quite computationally burdensome, the parameter space was segmented into regions which captured most of the variability in the likelihood function and end-point elasticities. Rather than choose arbitrary decompositions of these parameter values, and to preserve some ease of interpretation, three discrete cases were taken to include the log-linear ($\lambda_j = 0$, $\gamma_j = 0$), the linear ($\lambda_j = 1$, $\gamma_j = 1$), and the semilog ($\lambda_j = 0$, $\gamma_j = 1$) functional forms. Among this subset the likelihood function is evaluated and a preferred functional form chosen.

31. A current research topic is the effect of competitive influences represented by MTS and by offerings of other long distance carriers. The influence of these variables would in general seem to be characterized by nonconstant elasticities, and one way of generalizing the scheme described here is to allow more than one right-hand side transformation parameter. This has led to a consideration of three parameter schemes within an essentially hybrid-functional framework. As computational costs decrease and computational algorithms improve, these considerations may lead to multiparameter continuous Box-Cox solutions to the selection of functional form.

32. One observation of the research to date is that long-run price elasticities have not been very sensitive to the particular PDL scheme imposed nor to the length of lag chosen in the range of zero to eight quarters. These details, however, do affect how quickly the adjustment process is estimated to have "run its course" and are still an active area of research. For a particularly interesting approach to this problem, which addresses many of the issues from the point of view of telecommunications demand, see Kelejian and Murphy [8].

33. If a random parameter approach were taken, in addition to the 480 mean current and lagged price coefficients and the 250 mean current and lagged economic activity coefficients, there would be 49 times this number of individual state coefficients. Current RES research is moving in this direction and would essentially provide a geographically disaggregated version of the model.

Appendix

This appendix contains summaries of the Rate Evaluation System (RES) model results for both the message per telephone and average revenue per message equations. In the past, the disaggregate results of the RES model have been reported in terms of their elasticities as well as appropriate summary statistics. This has been convenient in that elasticities readily characterize the demand and revenue relationships of this telecommunications market; it also provides a standardized measure of the slope coefficients of the various functional forms of the RES model.
However, since disaggregate elasticities comprehensively summarize the telecommunication market demand of AT&T, they are now regarded as proprietary information. Statistical evaluation of the RES model, therefore, requires presentation of the coefficient results in a form other than elasticities.

The results presented here are suggested by considering that any regression of the form

\[ Y = B_0 + B_1 X_1 + \ldots + B_n X_n + \epsilon, \]

where the constant has been suppressed by placing all the variables in deviation form from their respective means, may be written in an alternative standardized form. Writing the model in the following way,

\[ Y = B_0^* + B_1^* (X_{11}/S_{X_1}) + \ldots + B_n^* (X_{1n}/S_{X_n}) + \epsilon, \]

results in a standardized model in which the coefficients \( B_i^* \) are the partial correlation coefficients, which range from zero to one in absolute value. The instruments of this standardization, \( S_{X_1} \) and \( S_{X_n} \), represent the standard deviations of the residuals when \( Y \) and \( X_i \) are each in turn regressed on the variables \( X_{12}, \ldots, X_{1(i-1)}, X_{1(i+1)}, \ldots, X_{1n} \). The coefficients of the original regression model are closely related to the corresponding partial correlation coefficients, that is,

\[ B_i^* = B_i (S_{X_i}/S_{X_1}). \]

The rescaling associated with the standardized model makes it possible to compare coefficients directly, in the same manner as elasticities. Partial correlation coefficients (when squared) measure the percentage of the variation in the dependent variable (after correcting for the influence of the other variables) explained by each independent variable, and thus provide a ready basis for the comparison of the relative and absolute explanatory power of variables included in the regression. The summary statistics of the standardized regression, such as the \( t \) statistics, the \( R^2 \) and \( F \)-statistics, the Durbin-Watson statistic, as well as other unit free summary measures, are exactly the same as in the nonstandardized regression model. Coefficients of the standardized model face the same statistical criteria as do the coefficients of any other regression model and hence offer the same possibilities for thorough statistical evaluation and validation of the model.

The following tables summarize the results for the business and residence equations in terms of the partial correlation coefficients, the standard errors of the partial correlation coefficients, the \( t \) statistics, and other summary statistics such as the \( R^2 \), \( F \), and von Neumann ratio (VNR). The \( R^2 \) and \( F \)-statistics measure only the influence of the listed independent variables (not the individual constant terms), as is the practice in applications where pooling is not used in estimation. The von Neumann ratio, as generalized here for pooled models, is a large sample test of the adequacy of the specification for autocorrelation. The VNR has a probability limit of two under the null hypothesis of first-order autocorrelation.

In addition to the partial correlation coefficient corresponding to each model coefficient, a partial correlation coefficient corresponding to the net price elasticity (see note 28) of each message per telephone equation is also included. In general, the sign and statistical significance of these coefficients are consistent with theoretical expectations which are posited for them. An analogous term is included for the ARPM equations, which is the partial correlation coefficient corresponding to the elasticity for a proportionate change in initial and overtime period prices. The zeros which appear in certain cases reflect the type of restrictions described in notes 26, 27, and 28. Tables A1 and A2 present the results for the message per telephone equations. Tables A3 and A4 present the results for the ARPM equations.

*See Johnston [7, pp. 132-35]. Note that in the case of GLS pooled models a generalization which involves weighted means and the standard deviations of transformed regressions is required.
### Table A1

**PARTIAL CORRELATION COEFFICIENTS**

<table>
<thead>
<tr>
<th>Market</th>
<th>N</th>
<th>R</th>
<th>Function</th>
<th>Form</th>
<th>Gain</th>
<th>Loss</th>
<th>Gain%</th>
<th>Loss%</th>
<th>R²</th>
<th>t</th>
<th>n</th>
<th>p</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct 1</td>
<td>1</td>
<td>1</td>
<td>Log-linear</td>
<td>$-0.452 (0.068)$</td>
<td>$0.424 (0.083)$</td>
<td>$-0.384 (0.059)$</td>
<td>$0.912 (0.091)$</td>
<td>0.16</td>
<td>2.11</td>
<td>140.58</td>
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</tr>
<tr>
<td>Day</td>
<td>2</td>
<td>2</td>
<td>Log-linear</td>
<td>$-0.419 (0.086)$</td>
<td>$0.323 (0.055)$</td>
<td>$-0.079 (0.033)$</td>
<td>$0.175 (0.025)$</td>
<td>0.30</td>
<td>2.11</td>
<td>0.917</td>
<td>97</td>
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</tr>
<tr>
<td>3</td>
<td>Linear</td>
<td>$-0.367 (0.082)$</td>
<td>$0.315 (0.053)$</td>
<td>$-0.057 (0.031)$</td>
<td>$0.143 (0.023)$</td>
<td>0.30</td>
<td>2.04</td>
<td>75.46</td>
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<tr>
<td>4</td>
<td>Linear</td>
<td>$-0.394 (0.082)$</td>
<td>$0.162 (0.022)$</td>
<td>$-0.057 (0.034)$</td>
<td>$0.141 (0.020)$</td>
<td>0.34</td>
<td>2.04</td>
<td>296.45</td>
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</tr>
<tr>
<td>5</td>
<td>Linear</td>
<td>$-0.371 (0.080)$</td>
<td>$0.070 (0.021)$</td>
<td>$-0.004 (0.021)$</td>
<td>$0.043 (0.021)$</td>
<td>0.16</td>
<td>1.95</td>
<td>141.11</td>
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<td>6</td>
<td>Linear</td>
<td>$-0.367 (0.074)$</td>
<td>$0.070 (0.021)$</td>
<td>$-0.004 (0.021)$</td>
<td>$0.043 (0.021)$</td>
<td>0.16</td>
<td>1.95</td>
<td>141.11</td>
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<tr>
<td>Direct-Dis 1</td>
<td>1</td>
<td>1</td>
<td>Semi-log</td>
<td>$-0.386 (0.036)$</td>
<td>$0.293 (0.021)$</td>
<td>$-0.254 (0.021)$</td>
<td>$0.039 (0.021)$</td>
<td>0.34</td>
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<td>276.96</td>
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<tr>
<td>Linked Day &amp; Night</td>
<td>2</td>
<td>2</td>
<td>Log-linear</td>
<td>$-0.614 (0.016)$</td>
<td>$0.397 (0.020)$</td>
<td>$-0.066 (0.005)$</td>
<td>$0.131 (0.005)$</td>
<td>0.44</td>
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<td>Linear</td>
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<td>$0.049 (0.001)$</td>
<td>0.35</td>
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<td>4</td>
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<td>$-0.529 (0.012)$</td>
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<td>$-0.001 (0.001)$</td>
<td>$0.026 (0.001)$</td>
<td>0.28</td>
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<td>5</td>
<td>Linear</td>
<td>$-0.479 (0.009)$</td>
<td>$0.034 (0.001)$</td>
<td>$-0.000 (0.000)$</td>
<td>$0.021 (0.000)$</td>
<td>0.20</td>
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<td>6</td>
<td>Linear</td>
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<td>$0.008 (0.000)$</td>
<td>$-0.000 (0.000)$</td>
<td>$0.010 (0.000)$</td>
<td>0.09</td>
<td>1.49</td>
<td>1587.01</td>
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<tr>
<td>Station</td>
<td>1</td>
<td>1</td>
<td>Log-linear</td>
<td>$-0.324 (0.033)$</td>
<td>$0.009 (0.000)$</td>
<td>$-0.024 (0.002)$</td>
<td>$0.267 (0.007)$</td>
<td>0.17</td>
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<tr>
<td>2</td>
<td>2</td>
<td>Log-linear</td>
<td>$-0.312 (0.033)$</td>
<td>$0.009 (0.000)$</td>
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<td>$0.267 (0.007)$</td>
<td>0.17</td>
<td>2.00</td>
<td>182.46</td>
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<tr>
<td>3</td>
<td>Linear</td>
<td>$-0.274 (0.028)$</td>
<td>$0.004 (0.000)$</td>
<td>$-0.014 (0.001)$</td>
<td>$0.194 (0.004)$</td>
<td>0.19</td>
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<td>4</td>
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<td>$-0.232 (0.020)$</td>
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<td>$0.178 (0.003)$</td>
<td>0.22</td>
<td>1.88</td>
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<td>5</td>
<td>Linear</td>
<td>$-0.200 (0.015)$</td>
<td>$0.000 (0.000)$</td>
<td>$-0.003 (0.001)$</td>
<td>$0.132 (0.001)$</td>
<td>0.25</td>
<td>1.72</td>
<td>120.90</td>
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</tr>
</tbody>
</table>

* Standard errors are in parentheses with statistics immediately below in brackets.

### Table A2

**PARTIAL CORRELATION COEFFICIENTS**

<table>
<thead>
<tr>
<th>Market</th>
<th>N</th>
<th>R</th>
<th>Form</th>
<th>Gain</th>
<th>Loss</th>
<th>Gain%</th>
<th>Loss%</th>
<th>R²</th>
<th>t</th>
<th>n</th>
<th>p</th>
<th>Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>C-daily</td>
<td>1</td>
<td>1</td>
<td>Log-linear</td>
<td>$-0.388 (0.070)$</td>
<td>$0.371 (0.070)$</td>
<td>$-0.333 (0.068)$</td>
<td>$0.362 (0.068)$</td>
<td>0.56</td>
<td>2.16</td>
<td>462.10</td>
<td></td>
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</tr>
<tr>
<td>2</td>
<td>2</td>
<td>Log-linear</td>
<td>$-0.388 (0.070)$</td>
<td>$0.371 (0.070)$</td>
<td>$-0.333 (0.068)$</td>
<td>$0.362 (0.068)$</td>
<td>0.56</td>
<td>2.16</td>
<td>462.10</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Linear</td>
<td>$-0.354 (0.066)$</td>
<td>$0.321 (0.061)$</td>
<td>$-0.303 (0.058)$</td>
<td>$0.282 (0.058)$</td>
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<td>3.11</td>
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<tr>
<td>4</td>
<td>Linear</td>
<td>$-0.342 (0.061)$</td>
<td>$0.272 (0.053)$</td>
<td>$-0.294 (0.055)$</td>
<td>$0.244 (0.055)$</td>
<td>0.53</td>
<td>2.70</td>
<td>427.93</td>
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<tr>
<td>5</td>
<td>Linear</td>
<td>$-0.342 (0.061)$</td>
<td>$0.142 (0.043)$</td>
<td>$-0.321 (0.053)$</td>
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<td>0.49</td>
<td>2.37</td>
<td>475.93</td>
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</tbody>
</table>

* Standard errors are in parentheses with statistics immediately below in brackets.

### Methodology Notes

- **Direct-Dis** represents the relationship between direct and displacement markets.
- **C-daily** indicates data collected daily.
- **Station** refers to fixed market relationships.
- **Period** denotes data collected over defined periods.

### Additional Notes

1. **Standard** errors are in parentheses with statistics immediately below in brackets.
2. **IV** (Instrumental Variables) models are used in some cases to address endogeneity issues.
3. **IV** models may require additional assumptions about the instruments used.
4. **IV** models may lead to biased standard errors if not properly specified.

---

*Susan Brown and Scott Teppich*
### Table A2 -- continued

<table>
<thead>
<tr>
<th>Market Segment</th>
<th>Location</th>
<th>Market Size</th>
<th>Functional Form</th>
<th>Demand Elasticity</th>
<th>Supply Elasticity</th>
<th>Price Change</th>
<th>Revenue Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Street Car</td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Day</td>
<td>Short-run</td>
<td>0.892 (0.008)</td>
<td>0.796 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td></td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Street Rail</td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Day</td>
<td>Short-run</td>
<td>0.892 (0.008)</td>
<td>0.796 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
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<tr>
<td></td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
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<td>0.001 (0.004)</td>
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<td>Suburban</td>
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<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Day</td>
<td>Short-run</td>
<td>0.892 (0.008)</td>
<td>0.796 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td></td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
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**Table A3**

<table>
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<tr>
<th>Market Segment</th>
<th>Location</th>
<th>Market Size</th>
<th>Functional Form</th>
<th>Demand Elasticity</th>
<th>Supply Elasticity</th>
<th>Price Change</th>
<th>Revenue Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Street Car</td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Day</td>
<td>Short-run</td>
<td>0.892 (0.008)</td>
<td>0.796 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td></td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Street Rail</td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
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<td>Day</td>
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<td>0.892 (0.008)</td>
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<td></td>
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<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
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<td>0.001 (0.004)</td>
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<tr>
<td>Suburban</td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
<tr>
<td>Day</td>
<td>Short-run</td>
<td>0.892 (0.008)</td>
<td>0.796 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
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<tr>
<td></td>
<td>Long-run</td>
<td>0.894 (0.008)</td>
<td>0.795 (0.013)</td>
<td>-0.253 (0.009)</td>
<td>0.195 (0.009)</td>
<td>0.916 (0.004)</td>
<td>0.001 (0.004)</td>
</tr>
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</tr>
<tr>
<td>--------</td>
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</tr>
</tbody>
</table>

References


There is currently substantial concern in Congress and among state regulatory commissions about anticipated increases in residential telephone rates. Monthly charges for basic service, which now average about $10.00 per month, are anticipated to double or triple if set to cover all nontraffic sensitive costs. Many legislators and regulators apparently fear that these increases could make telephone service unaffordable to low income consumers and substantially reduce telephone subscription among such households.

In part, these concerns have arisen from a study which I did for AT&T in 1978. That study evaluated the effect of access charges on the percentage of households with phones. It suggested that a $10.00 increase in access price would result in roughly a seven point decline in the percentage of households with phones and that the decline would be concentrated among low income households. My 1978 study has been used (and in some cases misused) to suggest that currently contemplated rate increases will result in marked decreases in the percentage of households with phones in many states.

However, the 1978 study is based on 1970 data. Given the time that has elapsed since then, there is a basis for legitimate skepticism about this model’s accuracy in forecasting the effect of price changes occurring in the 1980s. In addition, the structure of telephone prices has changed over this period (there are more measured rate offerings, for example), and this may also influence consumer price
response. As a consequence, the Bell Operating Companies commissioned me to reestimate demand for telephone service using 1980 data. I now have some preliminary results from the new study and I would like to describe them here.

Methodology

Before discussing the results of the study, let me briefly summarize the methodology. The 1983 access demand model was developed by examining demand for telephone service for a large sample of households. Data were obtained from the 1980 Census for 50,428 households (a 1/1000 sample of all occupied U.S. housing units). These data indicate whether each household subscribed to telephone service, describe its socioeconomic characteristics (household income, age, education, employment status, and so forth), and assign each household to one of 3,194 geographical areas. These areas are cities, counties, or county groups selected so that each contains at least 100,000 households. Using exchange specific rate data provided by the Bell Operating Companies, we estimated the price at which telephone service was available in each. Statistical analysis was then used to estimate an equation relating the probability of a household subscribing to telephone service to price and to the household’s socioeconomic characteristics.

The parameters of the 1983 demand equation are summarized in Figure 1. They describe the effect of each independent variable on demand for telephone service. Figure 1 also contains the means of each independent variable. For purposes of exposition, the determinants of demand have been organized into three groupings: prices, economic and demographic characteristics, and area characteristics.

Four components of telephone price are examined in this model: (1) monthly service charge on one-party flat rate service; (2) monthly service charge and 3) calling price for one-party measured rate service; and 4) the installation charge. The model is structured to accommodate three types of rate areas: those with only flat rate service; those with both flat and measured rate service available to all subscribers; and those offering only flat rate service to some subscribers and both flat and measured rate service to others. The model’s structure allows the effect of the flat rate service price to be different in areas where it is the only rate option and in areas where measured rate service is offered.

The household characteristics examined in the model include household income; the age, education, employment status, and race of the household head; and the number of persons in the household and their distribution by age. We also distinguish households in which a language other than

<table>
<thead>
<tr>
<th>Year</th>
<th>Mean</th>
<th>Median</th>
<th>Coefficient</th>
<th>Significance</th>
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<tr>
<td>1983</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1983</td>
<td></td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 1
English is spoken and in which English is not spoken well. We distinguish among five household types: husband/wife, family headed by a male with no wife present, family headed by a female with no husband present, nonfamily core households, and multifamily female headed. We also distinguished between farm and nonfarm households.

Finally, the probability of a household subscribing to telephone service is related to the number of main lines and the number of main lines per square mile in each household's local calling area. These variables are included to ensure a potential externality in the demand for telephone service—the likelihood of any one household subscribing is a function of the number of other households subscribing. The equation described in Figure 1 forecasts the natural log of the odds of a household subscribing to telephone service as a function of household characteristics and price. (For readers who do not know, the odds of an event occurring equal the probability that it will occur divided by the probability that it will not. Thus, if the probability of a household having a phone is .95, the odds that it has a phone are .95/.05 or nineteen to one.)

The equation in Figure 1 can be used to forecast the probability of subscription to telephone service for any household or for an area. To make individual forecasts, each of the household's characteristics (income, education, age, number of persons, and so forth) the characteristics of the area in which the household lives (number of subscribers and density of subscribers in the local calling area), and each applicable telephone rates, multiplied by the appropriate parameter relating that characteristic to demand. The sum of these products equals the log of the odds of telephone subscription for the household, from which the probability of telephone subscription can be computed. By calculating probabilities of telephone subscription for a representative sample of households, the model can also be used to forecast the percentage of households in a specific socioeconomic group. By making these estimates at various price levels, one can determine the effect of alternative pricing policies on the percentage of households with phones.

The 1983 model differs from our earlier study in five key ways. (1) The 1983 model is based on 1980 Census data; the 1978 model was based on 1970 data. (2) Prices used in the 1983 model were measured more precisely than those used in 1978. Currently, the prices are based on data for 1,760 exchanges; in 1978 we used data for 100 Revenue Accounting Offices (RA0's). (3) The 1983 model includes prices for both flat and measured rate service. The 1978 model included only a single minimum access price. (4) The 1983 model relates access demand to the size of the local calling area; the

Results

There are five principal results of the new study. Let me summarize them briefly and then describe each in more detail.

First, the 1983 model suggests significantly lower price effects than the 1978 model. The average elasticity of the 1983 model is about 60 percent of that estimated in 1978. This decline occurs because there has been a marked increase in demand for telephone service between 1970 and 1980.

Second, access demand is primarily a function of minimum rather than average access charges. Thus, the provision of measured rate service with low access charges or of low priced two-party service can be expected to maintain relatively high levels of access demand even in the face of substantial increases in the price of one-party flat rate service.

Fourth, demand also depends upon local calling area.

Even at very low access prices, some households will not subscribe to telephone service unless they can make a large number of calls at low prices. This result suggests that decreases in telephone penetration do not necessarily reflect decreases in the "affordability" of access to telephone service.
1975 NEBA Telephone Demand Equation: Parameters and Mean Values of Variables

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Value</th>
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<th>Significance</th>
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<td>Interest</td>
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<td>4.11</td>
<td>-0.3500</td>
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</tr>
<tr>
<td>Rate Charges</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>Flat Rate Price (Flat Rate Area Only)</td>
<td>Dollars</td>
<td>11.967</td>
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<td>Measured Rate Access Price</td>
<td>Dollars</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Measured Rate Calling Price</td>
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<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Installation Price</td>
<td>Dollars</td>
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<td>-0.6565</td>
<td>2.21</td>
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<tr>
<td>Proportion With Measured Rate Service</td>
<td>Decimals</td>
<td>0.346</td>
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</table>

Household Characteristics

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<tr>
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<td>19.781</td>
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<td>Income</td>
<td>Ages</td>
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<td>875,000</td>
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<tr>
<td>Education of Householder</td>
<td>Years</td>
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<td>Race of Householder</td>
<td>Indicators</td>
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<td>-0.0034</td>
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<tr>
<td>Presence in Household</td>
<td>Adults</td>
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<td>-0.0608</td>
</tr>
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<td>Proportion Low Than 6</td>
<td>Decimals</td>
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<td>-</td>
</tr>
<tr>
<td>Proportion 6-13</td>
<td>Decimals</td>
<td>NA</td>
<td>-</td>
</tr>
<tr>
<td>Proportion 14-19</td>
<td>Decimals</td>
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<tr>
<td>Language Other Than English Spoken</td>
<td>Indicators</td>
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<td>-</td>
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<td>English Speaking Pct Of Prod At All</td>
<td>Indicators</td>
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<td>-</td>
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<td>Family Households, No Wife Present</td>
<td>Indicators</td>
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<td>0.0635</td>
</tr>
<tr>
<td>Family Households, No Husband Present</td>
<td>Indicators</td>
<td>0.335</td>
<td>0.0635</td>
</tr>
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<td>Nonfamily Household, Male Householder</td>
<td>Indicators</td>
<td>0.335</td>
<td>0.0635</td>
</tr>
<tr>
<td>Nonfamily Household, Female Householder</td>
<td>Indicators</td>
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<td>0.0635</td>
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<td>Nonfamily Household, Younger Household</td>
<td>Indicators</td>
<td>0.335</td>
<td>0.0635</td>
</tr>
<tr>
<td>Nonfamily Household, Older Family Household</td>
<td>Indicators</td>
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<td>0.0635</td>
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<tr>
<td>Number of Observations</td>
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<td>41,444</td>
<td>35,763</td>
</tr>
</tbody>
</table>

NA = Not available.

1 The mean demographic values are the means for the entire sample, including households for which rate data were not available, whereas the model was estimated using only those households for which rate data were available. Price and income values are expressed in 1969 dollars.

2 Coefficients measure the change in the national log of the number of new households having a telephone for a 1 unit change in the variable. The coefficients of price and income are adjusted to make them comparable with the new model.

3 The significance is the ratio of the coefficient to its standard error. Those parameter estimates are normally distributed and these values can be used to test hypotheses about the true value of each coefficient.

4 The 1978 model, the access price was an estimate of the lowest available rate prevailing in each of the areas sampled. Where measured rate service was available, these estimates were based on rate data which included those people subscribing to measured rate service.

5 None theretofore except 2 usually occurs because there was a marked increase in the level of telephone demand from 1970 to 1980. This shift in demand reflects an increase in the value of telephone.

Fifth, the market for telephone service is characterized by an externality. The value of telephone service to each subscriber increases as the number of subscribers on the network increases. This suggests that the price of telephone access should be set somewhat below the cost of access to promote the optimal size network. But the welfare gains from subsidizing access are quite small and might not justify the efficiency losses resulting from any practical subsidy program.

Price Level

First, consider the decline in price effects that has occurred between the 1983 and the 1975 model. This decline is illustrated in Figure 3, which shows the percentage of households with phones at alternative access prices, using both the current model and that developed in 1978. As this figure suggests, if all access prices were increased by $10.00 (from $10.00 to $20.00 per month for flat rates and from $5.00 to $16.00 for measured rates), the current model forecasts a reduction in the percentage of households with phones (hereafter referred to as the telephone penetration rate) of 3.6 percentage points (from 32.2 to 89.6 percent). By contrast, for the same price increase, the 1975 model forecasts a decline of 6.4 percentage points (88.2 to 81.8 percent) in the penetration rate. (Note that all dollar amounts used here are in 1980 dollars. A $10.00 increase in 1980 dollars is equivalent to about a $12.00 increase in 1983 dollars.)

The decrease in price effect between the 1978 and the 1983 models occurs because there was a marked increase in the level of telephone demand from 1970 to 1980. This shift in demand reflects an increase in the value of telephone.
service to most subscribers. The increase in value can be seen in Figure 4, which describes the telephone demand schedule as estimated from the 1963 model (based on 1980 data) and the 1978 model (based on 1970 data). This figure graphically illustrates the marked increase in demand for telephone service occurring from 1970 to 1980. As this figure indicates, the current model forecasts higher demand at any price level. For example, based upon the 1978 model about half of all households would have been willing to pay as much as $50.00 a month for telephone service in 1970. By 1980 the value of telephone service to these households had risen to about $80.00 per month. As a consequence of this rise in the value of telephone service, increasing price discourages fewer consumers from subscribing. Thus, the 1978 model implies that at a $30.00 price, only 73 percent of all households would subscribe. The current model implies that at the same price, 64 percent of all households would subscribe.

The marked increase in telephone demand occurring over the decade is of great importance in the current debate over access prices. Because of this increase, demand is much less sensitive to increases in access prices than would have been the case a decade ago. Thus, the goal of maintaining universal service and the goal of maintaining cost-based pricing are not as conflicting as they seemed to be when the 1978 study was done.

Moreover, the same factors which increased telephone demand over the last decade are likely to continue to increase demand throughout the 1980s. Some of these factors are increases in prices for other means of communication, reduced long distance toll rates, increases in the number of services available by phone, and an increased need for the phone as a source of security. If, as seems likely, these trends continue in the 1980s, they can be expected to offset, in whole or in part, the effect of increased access prices. For this reason, the effects described in Figures 3 and 4, even those associated with the new model, may overstate the effect of anticipated increases in access prices.

**Price Structure**

The results described above reflect the effect on telephone demand for raising all access prices, but almost all telephone subscribers are offered a choice among a number of service options. For somewhat more than half of all Bell subscribers, there is the choice between flat and measured rate service. In areas without measured rate service, there is generally a choice between one- and two-party service. Consequently, it is important to distinguish between the effect on access demand of raising all access prices and the effect of raising the price for one service while holding other prices constant. Such a comparison is described in Figure 5. Where measured rate service is not offered, increasing the flat rate access price by $10.00 reduces demand by 3.2 percentage points. If measured rate service is available (at a $6.00 access price and a ten-cent charge for local calls), the same increase in the flat rate price...
decreases demand by only 1.2 percentage points. Clearly, most consumers who would be driven off the network if all access prices rise will simply move to a lower cost option if only the flat rate rises. This result suggests that demand for telephone service depends primarily on the minimum charge for access, and as long as some low cost option exists, penetration will be quite high even if high prices are charged for enriched grades of service.

Some additional evidence suggests that this is also true when the low cost option is a multiparty rather than a measured rate service. In areas offering only flat rate service, we examined the separate effects of varying the one- and two-party access charges. Although the results, which are summarized in Figure 6, are not highly reliable in a statistical sense, they are certainly suggestive. They appear to indicate that increasing the one-party and two-party rates by $10.00 would reduce penetration by 4.2 percentage points. Raising just the one-party rate reduces demand by only 1.2 percentage points, or about one-fourth as much. Although the weak statistical significance of this result precluded its inclusion in our basic model, it is nevertheless worthy of note.

Although demand for telephone service is primarily dependent on a minimum access price, access demand is also sensitive to usage prices. This result is shown in Table 1, which describes penetration rates under various assumptions about the price of flat and measured rate service. As this table indicates, even at very low measured rate access prices, increasing either the flat rate price or the measured rate calling price will drive some users off the network. For example, if measured rate service were available at all at a $5.00 access price and a calling price of five cents, raising the flat rate access price from $10.00 to $30.00 reduces demand by almost two percentage points. Users who leave the network under these circumstances are those who want telephone service only if they can get on the network at low cost and make numerous calls at little or no charge. There is another group of subscribers who are not sensitive to flat rate prices, but are sensitive to measured rate usage charges. Thus, at a flat rate access price of $30.00 and a measured rate access charge of $5.00, reusing the measured rate usage price from five cents to twenty cents reduces access demand by an additional 1.8 percentage points.

These results call into question the use of telephone penetration as a measure of "affordability" of access to the telephone network. Table 1 suggests that, when faced with a high calling price, many households will not subscribe to telephone service, even at a very low access price. Yet, these same households will subscribe at higher access but lower usage prices. For example, there are more subscribers on the network at a measured rate access price of $10.00 and a usage price of five cents than at a measured rate access

| Table 1. Telephone Penetration Rates at Alternative Flat and Measured Rate Prices |
|---------------------------------|-----------------|-----------------|-----------------|
| Access price | Calling price $10 | $20 | $30 |
| $5 | 0.05 | 93.955 | 93.055 | 92.015 |
| 0.10 | 93.54 | 92.55 | 91.45 |
| 0.20 | 92.57 | 91.47 | 90.23 |
| 10 | 0.05 | 92.87 | 91.80 | 90.60 |
| 0.10 | 92.26 | 91.23 | 89.97 |
| 0.20 | 91.25 | 89.99 | 88.60 |
| 15 | 0.05 | 91.59 | 90.37 | 89.02 |
| 0.10 | 91.01 | 89.72 | 88.30 |
| 0.20 | 89.75 | 88.33 | 86.77 |

Note: Assumes 100 percent measured rate availability.
price of $5.00 and a usage price of twenty cents. Low penetration rates may result, therefore, not because subscribers cannot afford access, but because at prevailing usage prices subscription is not sufficiently attractive. If "affordable" access is the goal of public policy, this result suggests that telephone penetration provides, at best, an ambiguous measure of the attainment of that goal.

**Price Effects and Income**

The current model also enables us to examine the effect of price on telephone penetration by income group. Telephone penetration rates forecast from the current model, for six income groups at three price levels, are described in Table 2. As this table suggests, even at the current low price levels there are significant differences in penetration by income level: Households in poverty have about a 17 percentage point lower penetration rate than do the highest income households. Moreover, these differences in penetration are very sensitive to the price level. Thus, with a $10.00 increase in price, the spread in penetration between the lowest and highest income households rises to 28 percentage points. Put another way, most people who drop off the network when prices rise are low income households. Of those who leave when prices rise by $10.00, 27 percent are in poverty, 57 percent have incomes below twice the poverty level, and about 85 percent are in the lower half of the income distribution.

The pronounced effect of increased access price on low income households could be eliminated or mitigated by making a lower priced, lifeline service available to low income households. The effect of extending lifeline service to various subgroups of the population is also illustrated in Table 2. In columns (2) and (3) we compare the effect of increasing charges by $10.00, with and without the provision of a lifeline option. The lifeline service is a measured rate option with an access charge of $6.00 and a calling price of 9.5 cents per call. With no lifeline service, the $10.00 rise in access price increases the spread in penetration between the highest and lowest income households from 20 to 28 percentage points. However, if measured rate service is offered only to those in poverty, the spread is reduced to 23 percentage points, which is scarcely above the level prevailing now.

Since households in poverty constitute less than 12 percent of the population, the cost of this subsidy would be relatively small. This is illustrated in Table 3. Even if every household in poverty took the subsidy described here, the cost would only be $1.07 per month per residential subscriber not in poverty.

The provision of lifeline service to low income households is also a way to maintain high overall penetration while, nevertheless, assuring that most households pay the full cost of access. Thus, without any lifeline option, raising access charges by $10.00 would reduce penetration from the current 93 percent to 89.45 percent; providing lifeline service to households in poverty would increase penetration to 90.2 percent. Extending the option to those with incomes up to twice the poverty level increases overall penetration to 91.06 percent.

Of course, further increases in penetration could be achieved by extending the lifeline option to still higher income households, but this results in large increases in the extent of the subsidy for relatively small gains in overall penetration. Thus, by extending the lifeline option to the poverty population only, overall penetration is increased by 0.75 percentage points at a monthly cost of $116 per additional household on the network. Extending lifeline service to those whose incomes are one to two times the poverty level results in a further increase in penetration of 0.86 percentage points at a cost of $196 per added household. However, if the subsidy is extended to those whose incomes are two to
three times the poverty level, the increase in penetration is only 0.59 percentage points and the cost per added household is $310. As Table 3 indicates, further extensions continue to yield successively smaller increases in penetration for successively larger increases in cost. At some point, the added gains are simply not worth the cost.

Externalities

While maintaining the overall level of penetration or the level for low income households is often put forth as a rationale for subsidization, this rationale, if appropriate, could be applied to almost any commodity. If it is appropriate to subsidize telephone service in order to make it widely available, it is equally appropriate to subsidize food prices, health care costs, housing costs, automobile purchases, and so forth. Clearly, the argument for subsidies is less persuasive if it applies more broadly.

With respect to telephone service, however, there may be a more satisfactory argument advanced for subsidization. There is likely to be an externality in the demand for telephone service. This externality occurs because the value of telephone service to any one subscriber increases as the number of subscribers on the network increases. Thus, as network size increases, the value of telephone service increases. By setting low access prices, subscription to telephone service is encouraged, and this increases the value of telephone service to each subscriber. Given this externality, access prices should be set somewhat below the marginal cost in order to assure the optimal size network. Of course, the extent to which price should be discounted below cost depends on the size of the externality.

The current demand model attempts, in a limited way, to measure the extent of the externality. The model relates each household's probability of subscription to the number of subscribers and the number of subscribers per square mile in the local calling area. This enables us to estimate the effect on any one household's demand of increasing the number of subscribers in his or her local calling area. As illustrated in Figure 7, access demand does appear to be positively related to the number of subscribers in the calling area. It also appears to be positively related to subscriber density at least up to 2,000 phones per square mile. In excess of that number, however, phone density appears to be inversely related to telephone demand. One should not infer from this result that there is no externality or a negative externality beyond some density level. It is just that phone density is an imperfect proxy for network size. Where phone density is very high, population density is also high. As population density rises, it becomes increasingly easier to reach people by means other than a phone. In very dense cities, for
example, most people live very close to places they know and can easily reach them by visiting instead of phoning. Since phone density and population density are very closely correlated, the phone density variable provides a statistically biased measure of the network externality.

Because demand for telephone service is positively related to the size of the local network, the value of service to each subscriber rises as local network size increases. This is illustrated in Table 4, which describes the value of access (consumer surplus) to the average subscriber at various sizes of the local network. As this table suggests, the value of service is nearly 25 percent higher where there are 500,000 subscribers on the local network than where there are 25,000.

Because increasing penetration increases the size of the network, and because increasing the size of the network increases value to each subscriber, it is economically efficient to reduce access prices below the cost of access. In Table 5 we have tried to calculate the optimal price of telephone service assuming two different levels of access cost, $20.00 and $30.00. This calculation is made by selecting the price which maximizes the sum of consumer and producer surplus. While the extent of subsidization varies depending on underlying population density, the results suggest that, on average, prices should be set about $4.00 below access cost. Although significant, this is much smaller than the subsidies implicit in current access prices.

Moreover, the gains in social welfare from setting prices below cost are very modest. At a $20.00 access cost they average about five cents per household, and at a $30.00 access cost, about seven cents per household per month. These gains may not justify the administrative burden associated with subsidizing access. Furthermore, the magnitude of these

Table 4. Value of Telephone Service to the Average Household at Various Local Network Sizes

<table>
<thead>
<tr>
<th>Network size (number of subscribers)</th>
<th>Phones per square mile</th>
<th>Value of telephone service</th>
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</thead>
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<td>25,000</td>
<td>100</td>
<td>$56.02</td>
</tr>
<tr>
<td>50,000</td>
<td>200</td>
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<tr>
<td>100,000</td>
<td>400</td>
<td>$61.55</td>
</tr>
<tr>
<td>500,000</td>
<td>2,000</td>
<td>$68.40</td>
</tr>
</tbody>
</table>
Table 5. Optimal Telephone Access Prices at Alternative Estimates of Access Cost and Population Density

<table>
<thead>
<tr>
<th>Population density (pop./sq.mi.)</th>
<th>Access cost + $20 (dollars per household per month)</th>
<th>Access cost + $30 (dollars per household per month)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gain in social welfare</td>
<td>Gain in social welfare</td>
</tr>
<tr>
<td></td>
<td>(1)</td>
<td>(2)</td>
</tr>
<tr>
<td>50</td>
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</tr>
<tr>
<td>500</td>
<td>$14.67</td>
<td>$0.0692</td>
</tr>
<tr>
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<td>$13.46</td>
<td>$0.1016</td>
</tr>
<tr>
<td>3,000</td>
<td>$18.17</td>
<td>$0.0941</td>
</tr>
<tr>
<td>Average</td>
<td>$15.88</td>
<td>$0.0469</td>
</tr>
</tbody>
</table>

4 This is the gain in social welfare (consumer surplus plus producer surplus) attributable to charging the optimal price rather than the cost-based price.

The averages given are weighted averages based on the percentage of the population living in areas of the specified densities.

The results of this study indicate that the optimal price for telephone service is not significantly affected by changes in population density. The optimal price is determined by the marginal cost of providing the service, not by the size of the population. Therefore, the price of telephone service should remain relatively constant regardless of variations in population density.

Other Household Characteristics

The current access demand model also enables us to examine the effect of penetration of a number of characteristics other than price and income. These include age, education, household type, employment status, race, and region. Some of these other effects may play a substantial role in the establishment of service price. Table 6 summarizes the effect on penetration of household type, age, and income. At every income level, penetration is positively related to age. Furthermore, female-headed households with children and headship have markedly higher penetration rates than do male individuals. At high income levels, where penetration is quite high for all household types, the effects of age and household type are rather modest, but at low income levels these effects are more pronounced. For young male individuals, who are extremely likely to have phones, the same income level, for households in which both the husband and the wife are over age 65, penetration is nearly 96 percent. Similarly, even at the poverty level, female-headed households with children have penetration rates ranging from 64.2 to 96.8 percent.

Because of their higher penetration rates, female-headed and aged households are also less price sensitive than are younger households or male individuals. In Table 7 we have reported the price elasticity of telephone demand by age, income, and household type. Price elasticity measures the percentage change in telephone demand associated with a one percent change in price. As this table indicates, for a single male individual in poverty, a one percent increase in price results in a 0.20 percent decrease in telephone demand. But the same price increase results in a demand decrease of only 0.02 percent for an aged couple in poverty, and 0.01 to 0.07 percent for female-headed households with children. Thus, for the aged and for many female-headed households, the price elasticities of those in poverty are actually well below the average for the population. (The average price elasticity is about 0.03.) These results should serve to reduce some of the political concern about higher access prices. In part, this concern appears to be the fear that households which need a phone for security (aged and female-headed households, for example) will no longer be able to afford telephone service at the higher prices. These results suggest that households which need telephone service will continue to subscribe, even at prices well above current levels. These comparisons illustrate another very important point. While income and price are very important determinants of telephone demand, they are by no means the only ones. Education, family type, and age play very important parts in the demand for telephone service. Thus, controlling for income and price, telephone demand is heavily influenced by other factors which influence the taste for and the need for telephone service. This result should be a source of concern to those seeking to establish a specified level.
<table>
<thead>
<tr>
<th>Household type/age</th>
<th>Below poverty ($3,491)</th>
<th>1-2 times poverty ($8,636)</th>
<th>2-3 times poverty ($15,152)</th>
<th>3-4 times poverty ($20,761)</th>
<th>Above 6 times poverty ($44,022)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Male Individual</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>53.32%</td>
<td>66.66%</td>
<td>78.88%</td>
<td>85.58%</td>
<td>95.18%</td>
</tr>
<tr>
<td>45</td>
<td>73.19%</td>
<td>82.24%</td>
<td>89.27%</td>
<td>92.75%</td>
<td>97.36%</td>
</tr>
<tr>
<td>65</td>
<td>86.71%</td>
<td>91.47%</td>
<td>94.88%</td>
<td>96.50%</td>
<td>98.56%</td>
</tr>
<tr>
<td>Female head, 2 children between 6 and 12 years of age</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>84.24%</td>
<td>90.36%</td>
<td>94.59%</td>
<td>96.53%</td>
<td>98.93%</td>
</tr>
<tr>
<td>45</td>
<td>92.74%</td>
<td>95.59%</td>
<td>97.50%</td>
<td>99.36%</td>
<td>99.42%</td>
</tr>
<tr>
<td>65</td>
<td>96.83%</td>
<td>98.05%</td>
<td>98.86%</td>
<td>99.23%</td>
<td>99.69%</td>
</tr>
<tr>
<td>Husband and wife</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>79.05%</td>
<td>86.85%</td>
<td>92.50%</td>
<td>95.15%</td>
<td>98.49%</td>
</tr>
<tr>
<td>45</td>
<td>90.01%</td>
<td>93.86%</td>
<td>96.49%</td>
<td>97.69%</td>
<td>99.18%</td>
</tr>
<tr>
<td>65</td>
<td>95.54%</td>
<td>97.26%</td>
<td>98.29%</td>
<td>99.91%</td>
<td>99.56%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Household type/age</th>
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<th>1-2 times poverty ($8,636)</th>
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<th>Above 6 times poverty ($44,022)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Male Individual</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>-0.1977</td>
<td>-0.1412</td>
<td>-0.0894</td>
<td>-0.0611</td>
<td>-0.0204</td>
</tr>
<tr>
<td>45</td>
<td>-0.1139</td>
<td>-0.0752</td>
<td>-0.0454</td>
<td>-0.0307</td>
<td>-0.0112</td>
</tr>
<tr>
<td>65</td>
<td>-0.0563</td>
<td>-0.0361</td>
<td>-0.0217</td>
<td>-0.0148</td>
<td>-0.0061</td>
</tr>
<tr>
<td>Female head, 2 children between 6 and 12 years of age</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>-0.0667</td>
<td>-0.0409</td>
<td>-0.0229</td>
<td>-0.0147</td>
<td>-0.0045</td>
</tr>
<tr>
<td>45</td>
<td>-0.0307</td>
<td>-0.0197</td>
<td>-0.0106</td>
<td>-0.0069</td>
<td>-0.0025</td>
</tr>
<tr>
<td>65</td>
<td>-0.0134</td>
<td>-0.0083</td>
<td>-0.0048</td>
<td>-0.0033</td>
<td>-0.0013</td>
</tr>
<tr>
<td>Husband and wife</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>-0.0887</td>
<td>-0.0557</td>
<td>-0.0318</td>
<td>-0.0205</td>
<td>-0.0064</td>
</tr>
<tr>
<td>45</td>
<td>-0.0423</td>
<td>-0.0260</td>
<td>-0.0149</td>
<td>-0.0098</td>
<td>-0.0035</td>
</tr>
<tr>
<td>65</td>
<td>-0.0188</td>
<td>-0.0116</td>
<td>-0.0086</td>
<td>-0.0046</td>
<td>-0.0019</td>
</tr>
</tbody>
</table>
of telephone penetration as a social goal. The least costly way to achieve a goal is to subsidize consumption for those whose price elasticity is relatively high. If price elasticity is high only for low income consumers, who presumably are limited in their ability to pay, such a policy might seem to make sense. But if price elasticity is high for many consumers because their taste for telephones is low, such a policy is obviously inefficient. It results in society providing subsidies to increase telephone penetration for the very people who value it least. It would make much more sense simply to subsidize income and let consumers spend the money as they wish.

Reliability

The current model apparently provides highly reliable forecasts of telephone penetration rates. To illustrate this, we have examined the model's ability to predict penetration in each of the lower 48 states and the District of Columbia. A comparison of actual and predicted values is summarized in Figure 8. A review of state-by-state data indicates that the forecasts are within 2.0 percentage points of the actual value for 39 states containing 94 percent of the population. Based on a linear regression relating actual penetration to predicted penetration by state, the model accounts for 83 percent of the interstate variation in telephone penetration rates. The standard error of estimate based on the regression is 1.32 percentage points.
THE DEMAND FOR RESIDENTIAL TERMINAL EQUIPMENT: ROCHESTER TELEPHONE'S EXPERIENCE SINCE 1977

John Chan

The purpose of this paper is to review the response of residential customers to changing price levels and available alternatives for the single line telephone instrument. In this review I draw on the experience of Rochester Telephone Corporation and of the Cincinnati Bell Telephone Company.

In June 1977, four months before the Supreme Court refused to review the FCC's registration and certification decision, thus affirming interconnection by residential customers, Rochester Telephone began allowing its customers to interconnect their own instruments to the local network. In November 1977, charges were unbundled into access line, wired outlet, and instrument charges. By "unbundle" I mean a breakdown of these charges on customers' bills in addition to itemization on filed tariffs. At the same time, customers were also given the choice of purchasing their instruments in place. This paper will describe the experience of Rochester Telephone in the residential terminal equipment market from 1978 through 1982. In reviewing that experience, certain observations can perhaps be made that would be relevant to future customers.

Note: The author would like to thank Dallas Horn, Manager--Forecasting, Cincinnati Bell Telephone Company, for data used in this paper. He would also like to thank Brian Dick and Robert Ingram of Rochester Telephone for their comments.

Residential Terminal Equipment

Independent companies that still have a substantial residential terminal equipment lease base. In a larger context, the experience may be useful as other types of local service become more open to competition in the future. I have limited the study exclusively to residential single line instruments, omitting business terminal equipment. While the analysis may therefore be somewhat restrictive, the data used in the analysis are homogeneous and reliable.

Table I shows the number of residence stations in service at year end from 1977 through 1982. It also shows the monthly lease price of a standard rotary station and the price at which Rochester's customers could purchase a set in place. I have used the prices of a standard rotary for simplicity. Approximately 77% of Rochester's current residential lease base still consists of the standard rotary set. In addition, both the lease and purchase prices of the rotary set can be thought of as bench marks for setting the lease and sale-in-place (SIP) prices for other premium instruments (touch, slimline, and so forth).

A review of Table I indicates that from 1978 through 1980 the number of residence instruments in Rochester's lease base was stable at about 400,000. Although not shown in the table, for several years prior to the time when legal interconnection became effective, the number had also been around 400,000. Rochester Telephone's service territory can best be characterized as economically stable but exhibiting little growth since the mid-1970s. In 1981 the number of stations declined by approximately 12,000 sets. In 1982 the number declined by 52,000. Through the end of October 1983 the number had declined by an additional 49,000 sets. Even though Rochester's customers since 1978 have been made aware every month through their unbundled bills of what they were paying to lease their instruments, and that the SIP option was available, significant lease base erosion did not begin until 1981. This can be attributable to significant increases in the lease price implemented in 1980 and to increasing consumer awareness of the purchase alternative. The latter was due to several factors. First, in 1981 and 1982 Rochester Telephone conducted several direct response campaigns through bill inserts to promote consumer awareness of the SIP option, its prices, and their relation to the corresponding lease prices. Perhaps these inserts helped to "legalize" the ownership option in the consumer's mind. Second, the availability from other vendors of instruments with a variety of styles, shapes, and special features accelerated. Third, during this time the FCC's Computer II decision and the Modified Final Judgment were finalized. These proposed changes in the telecommunications market, and their implications for telephone users, were widely reported by the popular press.

Utilizing monthly data from 1978 through 1982, I have...
Table 1. Rochester Telephone Corporation, Residential Subscriber Information, 1977-1982

<table>
<thead>
<tr>
<th>Residence stations in service (year end)</th>
<th>Lease price, standard rotary (year end)</th>
<th>Sale-in-place price, standard rotary</th>
</tr>
</thead>
<tbody>
<tr>
<td>1977</td>
<td>$0.80</td>
<td>$23.95</td>
</tr>
<tr>
<td>1978</td>
<td>$0.80</td>
<td>$23.95</td>
</tr>
<tr>
<td>1979</td>
<td>$0.80</td>
<td>$23.95</td>
</tr>
<tr>
<td>1980</td>
<td>$1.20$</td>
<td>$23.95</td>
</tr>
<tr>
<td>1981</td>
<td>$1.45$</td>
<td>$23.95</td>
</tr>
<tr>
<td>1982</td>
<td>$2.00$</td>
<td>$23.95</td>
</tr>
</tbody>
</table>

- Lease price was $0.80 until March 10, 1980; $0.86 until May 1, 1980; $0.99 until December 10, 1980.
- Lease price was $1.20 until September 24, 1981.
- Lease price was $1.45 until July 19, 1982.

The hypothesis is that the relative price between the two alternatives plays an important role in the consumer's decision. As such, the ratio of the lease and purchase prices should be included as an independent variable. However, as shown in Table 1, the purchase price of a standard rotary has for all practical purposes remained constant between 1978 and 1982, at $23.95, when SIP was first introduced at Rochester Telephone. Therefore, the use of the lease price alone in the equation is sufficient. Also, since it is the relative price between the two alternatives that is considered important in affecting the choice of those consumers who already have access to the network, one need not adjust the lease price by some sort of price index (such as the CPI), since any adjustment would be made to both the numerator (lease price) and the denominator (purchase price), leaving the resultant ratio unchanged.

While Rochester Telephone's residential lease base includes more than the standard rotary instrument, it is by far the most prevalent type of instrument. The monthly rental price of a standard rotary is more or less used as a benchmark for the pricing of other single line instruments leased to residential consumers. Therefore, the standard rotary's price alone would be as good (and a less cumbersome) price variable, when considering the entire market as a whole, as some weighted price constructed from the monthly rental price of all single line instruments. The variable used in the equation to capture the income effect is the average weekly earnings of all factory production workers in the Rochester SMSA, from data compiled by the Division of Research and Statistics, New York State Department of Labor.

The dummy variables for both the price and income variables were included to capture the hypotheses that consumers' reactions to changes in price and real earnings were altered in 1981 and 1982, as discussed earlier. It is hypothesized that residential customers became more aware of the purchase alternative and also better informed of the relative price of lease versus purchase in those years. For a given price change, if consumers as a whole are more informed, their response may be quite different than when they are relatively less informed. The dummy variables have the value of zero for all observations before 1981 or 1982 and are equal to price or income for all observations during and after 1981.
or 1982. This allows an estimate to be made of how the slope coefficients for price and income have changed in 1981 and 1982.

The results of the inward station model are given in Table 2, of the outward station model in Table 3. The equations were estimated assuming the Almon polynomial distributed lag structure for the price and real earnings variables. The coefficients were obtained using a second-degree polynomial and the far end constraint. The results shown in Table 2 and Table 3 are based on a lag structure of six months, although they do not change significantly if the number of lags is increased or decreased. The equations were formulated with the variables expressed in natural logarithms. This formulation has the advantage that the estimated parameters of the variables are the elasticities themselves.

In both models the hypothesis of zero first-order autocorrelation could not be accepted at the 95 percent confidence level (as indicated from Durbin-Watson statistics of 1.67 and 2.04 for inward and outward activities, respectively). The Cochrane-Orcutt iterative procedure was applied and the equations estimated again. The use of this procedure did not significantly change the results.

In both cases the coefficients of the access line activity have the expected sign and the t-statistics are high. The dummy variables allowing for the change in slope in 1981 in real earnings are significant at the 95 percent confidence level in both models but only for outward activity in 1982. The coefficients are negative for both equations; therefore, the evidence is inconclusive as to whether consumers would prefer to lease terminal equipment (versus purchase) as their real earnings increase. In both cases the sum of the lagged coefficients of real earnings are not significant at the 95 percent confidence level.

The sum of the lagged price coefficients is negative and highly significant in the inward model, while the coefficients of the dummy variables allowing for a change in the slope of price variable are not significant at the 95 percent confidence level. The estimation results suggest that for a one percent change in price, inward station activity would be approximately 2 percent lower than otherwise be the case. Conversely, the coefficients of the dummy variables are positive and highly significant for both 1981 and 1982 in the outward activity model, while the sum of lagged price coefficients is not significant. The sum of these two coefficients shows that for a one percent increase in price, outward station activity would increase by approximately 1.37 percent. The statistical results indicate that while outward station activity may have been price inelastic prior to 1982, that is no longer the case today.

For comparative purposes I refer now to Table 4, which presents similar data from Cincinnati Bell. Other than the

---

Table 2. Rochester Telephone Corporation, Residence Terminal Equipment Inward Activity

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coefficient</th>
<th>t-Statistic</th>
<th>Sum of t-Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intercept</td>
<td>0.914</td>
<td>2.559</td>
<td></td>
</tr>
<tr>
<td>1981</td>
<td>0.170</td>
<td>2.816</td>
<td></td>
</tr>
<tr>
<td>1982</td>
<td>-0.657</td>
<td>-7.097</td>
<td></td>
</tr>
<tr>
<td>1983</td>
<td>0.040</td>
<td>2.517</td>
<td></td>
</tr>
<tr>
<td>1984</td>
<td>1.268</td>
<td>1.421</td>
<td></td>
</tr>
<tr>
<td>1985</td>
<td>-0.270</td>
<td>-3.085</td>
<td></td>
</tr>
<tr>
<td>1986</td>
<td>-0.273</td>
<td>-0.914</td>
<td></td>
</tr>
<tr>
<td>1987</td>
<td>-1.550</td>
<td>-1.446</td>
<td></td>
</tr>
<tr>
<td>1988</td>
<td>-1.510</td>
<td>-0.815</td>
<td></td>
</tr>
<tr>
<td>1989</td>
<td>-0.455</td>
<td>-2.311</td>
<td></td>
</tr>
<tr>
<td>1990</td>
<td>-0.449</td>
<td>-1.350</td>
<td></td>
</tr>
<tr>
<td>1991</td>
<td>-0.405</td>
<td>-1.340</td>
<td></td>
</tr>
<tr>
<td>1992</td>
<td>-0.630</td>
<td>-0.012</td>
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</tr>
<tr>
<td>1993</td>
<td>-0.309</td>
<td>-0.170</td>
<td></td>
</tr>
<tr>
<td>1994</td>
<td>-0.105</td>
<td>-0.222</td>
<td></td>
</tr>
<tr>
<td>1995</td>
<td>0.216</td>
<td>0.171</td>
<td></td>
</tr>
<tr>
<td>1996</td>
<td>0.319</td>
<td>0.171</td>
<td></td>
</tr>
<tr>
<td>1997</td>
<td>0.100</td>
<td>0.173</td>
<td></td>
</tr>
<tr>
<td>1998</td>
<td>0.096</td>
<td>0.173</td>
<td></td>
</tr>
<tr>
<td>1999</td>
<td></td>
<td></td>
<td>-0.001 -0.015</td>
</tr>
</tbody>
</table>
Residential Terminal Equipment

Table 4. Cincinnati Bell, Residential
Subscriber Information, 1977-1982

<table>
<thead>
<tr>
<th>Year</th>
<th>Residence Stations in Service</th>
<th>Lease Price Standard Rotary (Year end)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1977</td>
<td>807,289</td>
<td>-</td>
</tr>
<tr>
<td>1978</td>
<td>835,495</td>
<td>*</td>
</tr>
<tr>
<td>1979</td>
<td>865,969</td>
<td>*</td>
</tr>
<tr>
<td>1980</td>
<td>885,666</td>
<td>*</td>
</tr>
<tr>
<td>1981</td>
<td>885,102</td>
<td>$1.00b</td>
</tr>
<tr>
<td>1982</td>
<td>866,210</td>
<td>$1.50b</td>
</tr>
</tbody>
</table>

*The charge for an extension station was $1.00. A credit of $0.70 was given to customers who provided their own extension stations.

b"Unbundling" on tariffs occurred in May 1981.

*Lease price was $1.00 until March 1982.

case of Cincinnati Bell, "unbundling" in terms of filed tariffs occurred only in May 1981. At that time a one-time itemization of equipment charges on customer bills also occurred. It is interesting to note that from January through May 1981 Cincinnati Bell's lease base actually increased from 885,686 to 886,490. It then declined to 885,102 by year end.

Let us turn now to the experience of both companies in 1983. Cincinnati Bell had lost an additional 70,000 stations by the end of October, or about 10.2 percent of its 1980 year-end lease base. The comparable figure for Rochester Telephone is 32.8 percent. There is no indication that lease base loss for either company will slow in the foreseeable future. The cumulative difference between the two companies, in terms of the percentage of lease base lost, has increased slightly during the past ten months.

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Table 3. Rochester Telephone Corporation, Residential Terminal Equipment Outward Activity

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<table>
<thead>
<tr>
<th>Table 3. Rochester Telephone Corporation, Residential Terminal Equipment Outward Activity</th>
</tr>
</thead>
</table>
| consumers. As I mentioned earlier, for every month since 1977 Rochester Telephone customers received a bill that stated exactly how much they were paying for each leased instrument. This is not the case for Cincinnati Bell customers (or those in many other local operating companies), who are billed for a "bundled" service and equipment charge each month. While the existence of the unbundled bill may not stimulate the ownership option in and of itself, it reduces the "transaction cost" to those consumers who would consider the ownership option. Otherwise, consumers who wish to evaluate the lease versus purchase alternative would have to take the initiative to call the business office to find out the monthly lease price for the instruments they are leasing. In the

<table>
<thead>
<tr>
<th>Residence stations in service</th>
<th>Lease price standard rotary (year end)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1977</td>
<td>807,289</td>
</tr>
<tr>
<td>1978</td>
<td>835,495</td>
</tr>
<tr>
<td>1979</td>
<td>865,969</td>
</tr>
<tr>
<td>1980</td>
<td>885,666</td>
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<tr>
<td>1981</td>
<td>885,102</td>
</tr>
<tr>
<td>1982</td>
<td>866,210</td>
</tr>
</tbody>
</table>

*The charge for an extension station was $1.00. A credit of $0.70 was given to customers who provided their own extension stations.

b"Unbundling" on tariffs occurred in May 1981.

*Lease price was $1.00 until March 1982.
the experience of the two companies in 1983 is probably due
to differences in the lease price ($2.00 versus $1.50) and
the SIP price ($23.95 versus $28.95) for Rochester Telephone
and Cincinnati Bell, respectively.
In conclusion, after reviewing the experience of Rochester
Telephone in the residential terminal equipment market, I
feel certain inferences can be drawn that may be useful
to local operating companies that still have a substantial lease
base. First, theoretical analysis of demand assumes perfect
consumer information. Rochester's experience indicates that
if consumers are made aware of price and available choices,
they will respond even if the cost of the service amounts
to a relatively small portion of an average household's expen-
diture. As various new pricing mechanisms for local telephone
service are developed or implemented to induce consumer
response, it is important that information on price and alter-
atives be made readily available to consumers. Second,
the experience of Rochester Telephone and Cincinnati Bell
indicates that as consumers become more aware of price and
available alternatives, their response can change significantly
over a relatively short period. Specifically, for companies
whose residential lease base still accounts for a substantial
portion of local service revenue, this must be taken into
consideration in future pricing decisions. More generally,
even other local telephone companies, such as private lines,
become more open to competition, care must be taken not to
underestimate consumer response to price changes. Finally,
the extent that the sale of instruments from the embedded
lease base at realistic prices is a desirable objective (for
example, in order to minimize the risk of stranded investment
in the regulated lease base), Rochester Telephone's experience
may be useful to those local service companies which have
barely begun to experience erosion of their lease base. Despite
the relative obsolescence of the lease base in terms of
features and style, a substantial portion of consumers seem
to be willing to purchase them in place. However, time appears
to be running short. Currently, there are instruments with
extra features (automatic recchi and universal dialing)
available for $12.00-$15.00 in the Rochester area. At the
current lease rate of $2.67 for a basic touchtone set, a
customer faces a pay-back period of only several months.
In addition, with a standard 90-day warranty, a customer
would face only a relatively short period of maintenance
exposure. The age of "the disposable telephone" is nearly
upon us.
forecasting of a future rate year's earnings should be obvious to all. Sadly, this fundamental point needs to be emphasized along with the even more fundamental recognition of the distinction between gross revenues and net revenues.

Also basic to the building of good forecasting models is the recognition that there is a distinction between econometrics and forecasting. This distinction, which Doherty has argued so cogently in his presentation, is sadly not widely acknowledged among public utilities. It is my fervent wish that everyone involved in forecasting read Doherty's paper and understand his explanation of the difference between estimating coefficients in an econometric model and forecasting the dependent variable for a future rate year.

The use of the Theil-U statistic and ex post simulation should be an important and required statistical test for forecast evaluation. If all forecasters would simply acknowledge that their end product and goal is to forecast rather than to meet some predetermined cookbook value for a particular statistical test, the entire argument over proper forecasting would be vastly elevated.

With sufficiently complex mathematics, it is possible to fit a function to virtually any pattern of dots on a page. The resulting model will have a high R² and will most likely be useless for forecasting. In my experience, most utilities who forecast their rate years do not do a job testing of the ability of their models to forecast, let alone construct the models with an eye to forecasting. Once again I think Doherty's exposition of these issues is clear and concise, and I hope that his paper is widely disseminated.

On a somewhat more narrow note, Doherty's own econometric models represent an example of practical empirical results being derived through the application of sophisticated econometrics.

In a similar vein, I found the paper by Susan Groves and Scott Stephan to be a tour de force through modern, sophisticated, econometric modeling. The reservations I have concerning their paper lie in the basic overall model and not with any of the specific econometric techniques. I am intrigued by a data set that has 300 million records per year. Even with this rich a set it is still possible to get insignificant cell sizes, but the broadness of the basic model is bothersome in that the length of haul characteristic is divided into only five mileage bands. Specifically, the fifteen bands cover distances from 925 to 3,000 miles, and no distinction is made within a particular mileage band. In other words, a call from New York City to Chicago is treated the same as a call from New York City to North Dakota's Fall, South Dakota. Without having empirically examined the issue, I would guess that the calls were different, and I would wonder if there might be a problem of a heterogeneous sample which, if it could be segmented into the calls between the

Note: The ideas expressed here are solely those of the author and do not necessarily reflect the opinions of the New York State Department of Public Service or of the New York Public Service Commission.
larger areas and the smaller areas might show distinct and separate results with tighter coefficients.

The paper by John Chan reflects an earlier stage of inquiry than do the first two papers and, although interesting, requires more development both of the underlying model and of the econometrics used to test the model empirically. Basically, the Chan paper tells us that the data at Rochester Telephone are not inconsistent with the general economic theory that everything is more elastic in the long run than in the short run. The model is interesting and, as it is of no little importance for local operating companies to know just how much more elastic things are in the long run, I would urge further development. Some specific comments in the spirit of furthering such development include the following.

1. I think that the test for structural change should include a test for an intercept shift as well as just a slope shift. In this instance the slope shift by itself is an incomplete test for structural change.

The model itself seems to have many coefficients that are not significantly different from zero. There may be a multicollinearity effect causing so many insignificant variables. This should be examined and the model reformulated if necessary.

Although the use of nominal prices in a ratio as used by Chan does cancel out, it might well be the case that a price level effect is being lost by using the nominal price ratio which a real price variable would show up.

The negative income elasticities are quite explaining. It seems possible that the inward and outward movements are not independent, and a Zellner-Samuelson Unrelated Regression approach should be tried.

As a general comment, I think that anyone doing a study of consumers' awareness of different telephone sets and behavior toward the purchase of these sets should begin with a rereading of George Stigler's classic article, "The Economics of Information."1

The study by Lewis Perl is fascinating econometric research in a very different area. My comments will largely be centered on methodology and on further interpretation of the econometric results in light of consumer demand theory, an approach that Perl partially applies near the end of his paper and a general discussion including a word of warning about the interpretation of econometric results.

I have no complaints about Perl's specific econometric techniques. My major criticism is that he has performed an econometric analysis before thoroughly investigating the implications of consumer demand theory. Specifically, he has not generated hypotheses suggested by consumer demand theory as the starting point and then used the econometric study to support or not support the hypotheses. The present approach seems to suggest that econometrics can tell us what the world is like. This is an unfortunate, but not unusual, overselling of econometrics.

I will start by anticipating my final criticism of the paper and stating the simple truth which all econometricians recognize: in the abstract and then so often neglect in practice: Correlation does not imply causality. All that a regression can ever tell us is whether one thing is likely to vary along with something else. It does not and cannot imply that one thing causes something else to happen. Only a theory can imply causality.

The model of his study, Perl discusses consumer surplus and correctly notes that it is a measure of value to a specific customer of having telephone service. Indeed, changes in the measure of consumer surplus can provide explanations for all the results in Perl's study, and it therefore can be viewed as empirical support for consumer demand theory. The problem can be viewed as an analysis of the demand for the initial calls under a multipart tariff. The fixed part of the tariff, here the access charge, is limited by the amount of consumer surplus. This type of pricing problem has been exhaustively analyzed by Walter E.2

At the beginning of his study, Perl lists five principal results. I will review the concept of consumer surplus as a part of demand theory and then show that each of these general results would be predicted a priori by this theory.

If we assume, as is reasonable to do, that the ratio of the marginal utility of a phone call to the marginal utility of all other goods is greater than the ratio of the price of a phone call to the price of all other goods for the initial phone calls completed per period, then the inclusion of whether to have a telephone depends on the price of phone calls will vary with the consumer's comparison of his or her total consumer surplus with the fixed monthly charge (sometimes called the access charge).

To the extent that the initial phone calls, for example, those used for calling for help or keeping in touch with family and friends, have a very high marginal utility (in other words could be considered necessities), then it follows that the initial portions of the consumer's demand curve would be relatively inelastic. From this it follows that the consumer surplus involved will be large relative to the existing level of fixed customer charges. This explains why relatively few people do not have telephones. The person to whom the telephone is truly important will be on the network now and will not drop off the network when the access price increases. Perl finds support for this in his empirical studies when he notes that elderly people who rely on telephones will pay substantially more than the present price before leaving the system.

The converse is also true. Consider the situation in which we somehow increase the access charge but hold real
Incomes constant in a Slutskyian sense. The person who is not on the system or who will readily drop off the system when the price increases is the person for whom the telephone is less important in the sense that the person has a more elastic demand for telephone calls and therefore has a smaller consumer surplus. This small consumer surplus, which is another way of saying more elastic demand for calls, implies that the person who drops off readily has alternative substitutes available. This is consistent with the finding that in very high density urban centers personal contact is a substitute for telephones; therefore, the demand is more elastic, the consumer surplus smaller, and a less firm attachment to the network is found to exist on the part of the customers. In some urban areas, people in one apartment in a building will have a telephone and share it with their neighbors, providing a ready substitute for individual phones.

All of this is supported by Perl's empirical work; however, if the people who are not on the system now are different—albeit in their access to substitutes for telephones or in some other way—from the rest of the population, then an omitted variable may be causing the price of access variable coefficients to overestimate the true price effect.

Before further econometric work is done, it would be interesting to try to determine how the people who are not on the telephone system differ from those on the system. To the extent there are differences other than just age, income, and regional access price, then the implications and generalizations which can be drawn from the empirical measurements are less strong than they would appear to be and the response to access price increases smaller than measured in the current study.

Figure 1 summarizes the above discussion of consumer surplus. AE is the demand curve for phone calls of a typical telephone customer. At a price of 00 per telephone call, the consumer chooses to make 00 units of telephone calls, a quantity at which the consumer equates the ratio of his or her marginal utility of phone call and his or her marginal utility of all other goods consumed, to the ratio of the price of a phone call to the index price of all other goods. The total consumer surplus enjoyed by this consumer over this period is shown by the area under the demand curve ABD. So long as this customer stays on the network, the access charge will enter his or her behavior only insofar as it represents a decrease in the consumer's income and, as such, causes the line AE to be closer to the origin than it would be in the absence of an access charge, assuming that telephoning is a "normal" good. At the point at which the customer charge becomes greater than the consumer surplus, the customer drops off the telephone network entirely.

Using the Slutsky equations, it can be shown that the shift inward of the demand curve AE caused by an increase in the access charge will be equal to the income elasticity of phone calling times the percentage of the customer's income represented by the change in the access charge. This, of course, is also true in a positive direction, in which we would observe the demand curve AE shifting out and therefore causing an increase in consumer surplus, and the value of having a phone, as incomes increase. This explains part of the greater network attachment shown in the present study relative to that shown in Perl's 1978 study.

Still referring to Figure 1, the total welfare gain to society from having a telephone is shown by the sum of consumer surplus and producer surplus, as Perl mentions. After 01, in the article cited above, shows that society's total welfare will be maximized by setting the price per call 00 equal to the marginal cost per call, and then recovering all nuisance sensitive costs with a fixed access charge.

Returning to Perl's five principal results in the new study, the first is that the demand for telephones has increased. In theory, this would be implied by the increase in consumer surplus caused by the shifting out of the demand for phone calls which would be expected from the increase in incomes over the period. The second result is also consistent with the consumer surplus approach in that it is the minimum access charge.
which must be less than the consumer surplus in order for the customer to be on the network.

The third result further supports consumer theory. As the price per call decreases, it can be seen that the consumer surplus (represented by the area ADB) increases. In other words, the lower the price per call the more valuable becomes the network access. This points up the importance of looking at the access charge and the price per call as part of a single package confronting the consumer. It is quite possible that an increase in consumer surplus caused by a decline in price per call accompanied by an increase in access charge might leave consumers with the same consumer surplus, therefore the same value of telephone service, and therefore the same demand rate overall. Perl has not shown that an increase in access charges accompanied by a decrease in usage charges would reduce penetration. A measure of the effect of changes in the access price of telephones independent of the effect of changes in the unit price of phone calls will be misleading. Since, as Perl empirically demonstrates, the decision to have a telephone depends on both the access charge and the price per call and, furthermore, given that the proposals to increase the access price of telephones are virtually all linked to a decrease in the price of toll calls, it is the joint effect of these two changes which has significance for policy decision making. It is well to note that these two changes operate in opposite directions and under reasonable assumptions might cancel each other out. To the extent that they change together, the measurement of the access price change by itself must overestimate the actual effect that occurs.

This relationship is supported by Perl's empirical work, which shows that there will be more subscribers on the network at a measured rate access price of $10.00 and a usage price of 20 cents than at a measured rate access price of $5.00 and a usage price of 20 cents. I suspect that Perl has not emphasized strongly enough that these two changes will and, I will offer a general comment and warning about the interpretation and overselling of econometrics. Many of my previous comments have reflected my unease about the interpretation of econometrics, which to many non-econometricians has an aura of magic about it. Econometrics is, indeed, a very powerful analytical tool, and its use has furthered our understanding and knowledge in many areas of economics. It also has severe limits; it is not a crystal ball. In fact, it can never prove anything. Once an hypothesis has been made on the basis of economic theory, econometrics can be used to disprove the hypothesis. The hypothesis based on theory must be the starting point. An hypothesis can be the best existing one until it is displaced by another. An entirely different econometric result may be consistent with the hypothesis, may not disprove, any number of different and occasionally conflicting hypotheses. The problem then becomes finding an empirical test which can differentiate between the competing hypotheses.

If one hypothesizes that there is a causal relationship between two things—such as access charges and the number of telephone customers—and then finds that a regression shows no relationship between these two things, the hypothesis is probably wrong. If the regression shows a statistically significant relationship between the access charge and the number of telephone customers, then the hypothesis has not
been shown to be highly unlikely, but it has not been proven true. Before accepting the hypothesis that there is a causal relationship between access price and the number of customers, alternative hypotheses must be searched for to see whether there is a better explanation that is consistent with the data or that would explain better some portion of the observed (and hypothetical) relationship. A regression cannot and never does show causality. All it may show is a statistical relationship between variations in two or more variables. It in no way implies that there is a causal relationship, much less that the causality runs in a specific direction.

In the Perl study there is a sentence which states: “Put another way, most people who drop off the network when access prices rise are lower income households.” This is an overstatement. All the regression shows is that people with lower incomes have a greater chance of not having telephones than do people with higher incomes, and that this chance is higher in areas where the access charge is higher. Other factors may in fact be more important in explaining what happens at the margin. Some people may be transients and that transience may be related to both the low recorded income and the absence of a telephone. When the price per call is reduced at the same time as the access prices rise, there may be no drop off. In any case, it is overselling the statistical results to draw the conclusion that when the price increases, a greater number of low income people will leave the system. This may in fact happen, but this observation is not warranted based on the statistical analysis Perl has done.

An alternative and I think a stronger if less easily proven hypothesis would be that the number of low income people who would leave the system when the access price increases depends on the accompanying decrease in long distance and unit phone rates and on the number of local and long distance calls made by the population in question. It is possible that Congress is trying to protect poor people from something that will, in fact, make many of them better off.

Notes


3. An example of an omitted variable which by itself might explain a significant amount of the different proportions of poor people and nonpoor people who have phones, and
I would like to review the papers by John Chan, Susan Grove and Scott Stephan, Noel Doherty, and Lewis Perl in that order, which differs from their order of presentation. All the work is necessary and useful research.

Chan's paper is most useful but not the econometrics, which has problems that will be covered briefly below. What is very useful is the policy implications of what Rochester did. The company made available information on the price of the terminals: what it was costing the consumer to lease these, and what it would take to sell the consumer phone. That was all very useful and presented the advantages of such a campaign. The paper is to be commended for this discussion.

When trying to measure the effects of the policy, we run into some serious problems with the analysis. Note that Chan used the normal lease price of 80 cents (which increased later in the period). He went through a rationale of why that should be the price of interest. He argued that we should really look at the lease price and also the terminal price of $23.00 plus, but since they are both in the same period it is not necessary to deflate. At the same time Chan was arguing not to deflate these prices, he deflated the income variable in the models. This is not cricket!

The second problem was that he only used the index of the one terminal price—the R1 Terminal—which makes up 70 percent of the terminals, but a weighted index of some kind should be used.

The third problem was with the use of dummy variables. These are not a problem per se, but it was not clear why Chan was using these particular dummy variables in the years they were used. Chan used two sets of dummies; one in one of the latter years and another in the following year. He hoped to capture the effect on consumers' awareness of the advertising which was being undertaken in the year. Better proxies for that kind of activity exist, such as the advertising revenues expended.

As indicated previously, the interesting part of the paper was the manner in which Rochester approached the problem of selling its in-place phones. This is very useful and offers lessons to other companies that would like to sell the leased phones to their customers.

The next three papers flow together because they are dealing with telecommunications service.

In reference to the paper by Grove and Stephan, the RES model has been used by AT&T Long Lines for some time. The company has had quite a bit of time to refine it and fine-tune its estimates; thus, the estimates should be scrutinized much more than we are able to do by examining a set of graphs.

Although the results are generally in accord with what I might believe, four comments are in order. The first about the independent variables that were and were not used. In the analysis, the variable "employment per phone" was used. I am uncomfortable with this; what is being captured? Why deflate the employment? I would have been more comfortable with an aggregate variable.

What Grove pointed out at the end of the presentation, which was not included in the paper, is the desire to include an index of OCC prices as an independent variable. We have done analysis which shows that within the time frame of 1978 and 1980, there were effects on toll demand as a result of OCC activities. This was not as detailed as we would have liked, but then we are not in the business. In dealing with toll demand, this kind of analysis should certainly be factored into the AT&T Long Lines approach. Perhaps they have these models but are not making them public!

There is a problem with the aggregation of the rate structure, which was broken down into five bands. There are nine rate bands currently, but Long Lines is only aggregating and pooling these into five. Low density traffic is mixed with high density traffic simply because of this aggregation.

In one of the models, the dependent variable is average revenue per message. Consider what that means: AT&T Long Lines (or whatever name it goes by today) measures the total revenue and then divides it by some measure of messages. Revenue is simply price times quantity (= revenue) divided by messages. This is regressed against three variables.
the initial minute price, additional minute price, and a measure of economic activity.

The initial price and the additional minute price are very closely related to the average revenues per message. Some algebra will show this as a note. Thus we have two price variables on the right-hand side of the equation, which estimates another price variable on the other side of the equation. This is not good econometrics.

Finally, after having seen Perl's results, we should consider whether in the long distance context the elasticities are variable over time, just as Perl hypothesizes there is a shifting of access demand over time. This would be interesting to explore.

The Doherty paper is a useful work. I will comment very quickly on the demand side, then I will discuss the cost side and make some suggestions. I am surprised that, being a member of the Bell family—at least until the end of December 1985—these were not picked up.

I am troubled by the employment variable used. It is a proxy and may be picking up business activity as well as residential activity. It may confound the results. There is a lack of symmetry in the matrix which showed cost compliments and pricing substitutes. Doherty uses aggregate indices for complementary and substitute goods. How are these aggregated together? How are we to interpret these?

Doherty's model should also explore the possibility of a shifting demand function, since he is using a fairly long time series for his estimations.

The last part of the paper develops the cost offset model. It ties the supply and demand issues together. So often we ignore the influence of one side or the other, and I am glad to see that New York Tel is connecting these elements. [Their model did so at the New York Public Utilities Commission's request]. However, a slightly different technique of cost estimation may be more appropriate. Recall that Doherty used a technique which estimated a set of expense and capital functions. Recent developments in economic theory—the so-called duality theory—address some of the problems which Doherty mentioned he was not able to handle, namely, the common and joint cost of cost compliments which may exist between services—which Theodore Val told us have existed through all these many years. The use of quality theory would allow for the estimator of these shared inputs and, at the same time, estimate the different marginal and average costs. With the judicious use of a capital adjustment model in the specification of the econometric formulation, the model would be able to estimate the technical change another problem with which the Doherty model was not able to deal. However, the model is a useful beginning. We are looking forward to additional work of this type. We trust these suggestions will be incorporated.

The Perl study is probably the most interesting—because of the results that he has recently obtained and comparisons with the past studies he supervised. We have seen the results of the 1975 study, the restatement of the study in 1978, and now the 1983 study. In the policy perspective, it has been meaningless to examine the price sensitivity or price elasticity by different demographic groups. I am pleased that this type of research is continuing. We think the work is "first class." In fact, we are so pleased that I must make a disclaimer at this point. We, at GTE, have a contract with Perl to do this type of analysis for the GTE exchange areas. If I say things that seem to be negative, assume they will be correct when the GTE results are in.

The results show a change in signs of some of the coefficients between studies. What is the explanation? Why do the signs change in the different age cohorts? It is not spelled out in the text. What explains the shift in signs between the 1970 and the 1980 studies for nonfamily households? What kind of significance should be attached to this? The density variable had this change in signs. These relationships should be explored. Incidentally, I did not see an explanation for using the age times income variable.

Perl was able to address the externality question in the analysis, but this variable is troubling. The relationship between this externality variable, which measures the number of telephones one can call, and the manner in which prices are set by both the Bell System and the independents are related. The latter is related to the size of the exchange.

If one lives in a larger exchange, one can reach more people, but the exchange price is also higher. If one lives in a small rural exchange, the price is lower. Is the model tracking the externality on the exchange price? The paper discussed how population density tracked exchange sizes. This is a similar phenomenon and, hence, has the same collinear problem. I think the analysis could be done in this analysis. It would be difficult, because of all the other variables addressed in the model. Moreover, the data do not lend themselves overall to the task. It would be very useful to examine these demographic groups with regard to their use of toll and relate that to their evaluation of the telephone. GTE found that local measured rates had an effect on subscriber penetration. The price of toll should be as well, and toll prices are one of the major elements that are changing in the telecommunications environment.

The definition of penetration was changed between the 1970 and the 1980 study. In 1970 the question was: "Did you have a phone available to you?" In 1980 it was: "Do you have a phone available in your home?" These differences in the answers are going to bias the results.
be aware of this. If the same question were asked in the 1980 study as in 1970, it would probably show the demand to be even more inelastic than the estimates indicated.

Finally, let me turn to the optimal pricing discussion. First, let us discuss a lump-sum tax. Hotelling suggested that solution more than 50 years ago. Any kind of lump-sum tax is going to be distorting, although the idea was a useful beginning. It sparked a debate in the economics literature which ultimately dismissed the idea. Frank Ramsey came along and developed the pricing methodology which now bears his name.

Second, Perl made this point, but I would like to amplify it: We should only be concerned with the marginal customer. If we are going to practice some type of subsidization scheme, one does not have to be concerned with all of the customers who are going to subscribe to the service, only with those marginal customers who are going to leave the system because the price is too high. This is precisely what the Allen and Schmidt paper in this volume suggests, namely, one should target the subsidy to the group who needs it. The subsidy should be funded out of general government revenue. Recognize that this is also going to be distorting, but it is much less distorting than when a whole class of customers must be subsidized.

It is interesting to note that Perl found a positive effect of measured service on subscriber penetration levels, which reinforces another point made in the Allen-Schmidt paper: Measured service can help ameliorate the effect of the FCC access charges.

The Perl study is a fine piece of research, and I urge the reader to examine it closely.

Note
1. The relationship is as follows:

$$ARPM = 2\epsilon [p_1 + p_2(1-q)d] = f(p_1, p_2),$$

where $p_1$ and $p_2$ are the initial minute and additional minute price, respectively; $q$ is the number of messages; and $d$ is the average message duration. The band and period subscripts have been dropped for notational convenience.

Part Four:
Issues in Local Exchange Pricing:
Local Measured Service and Lifeline Rates
The concept of local measured service, while certainly not new, has received increased attention recently due to increasing costs in service, increasing competition, and regulatory rulings, the most important of which is the recent FCC order in Docket 78-72. Local measured service, or usage sensitive service (USS), as it is termed in GTE, may offer a way of more closely relating telephone prices to costs, of encouraging the temporal reallocation of telephone usage, and of deferring any inefficient expansion of central office and transmission facilities. Yet, despite the potential of USS, relatively few studies have appeared on the welfare economics of usage pricing.\(^1\) Even fewer have attempted to examine the welfare gains in a quantitative manner. To a significant degree, this lack of quantification stems from uncertainties as to the magnitude of three crucial elements: (1) price elasticities of demand for usage, (2) estimates of the marginal costs of usage, and (3) the incremental costs of metering.

This paper will try to shed some additional light on the magnitude of these values by first establishing a methodology for judging when usage pricing can be economically justified. The metering arrangement proposed by GTE is then examined with the objective of calibrating the incremental costs of metering. Next is a review of some existing studies of the price elasticity of demand for local usage, followed
by a review of the available evidence on the marginal costs of outage. The parameters established in the three preceding sections are then combined using the methodology laid out to evaluate the efficiency effects of USS. Finally, some corrections and additional policy recommendations are offered on the relationship between measured service and access charges.

**A Basic Framework for Analysis**

In any industry structure it would seem a desirable goal of public policy to assure that the total value of the outputs produced by an industry less the total value of the inputs consumed by that industry in producing that output be as large as possible. In other words, for any given cost of industry output, the cost of producing that output should be minimized; alternatively, for any given cost of production, the value of the output should be maximized. In a broad sense, this is the concept which economists term economic efficiency. In equation form, this relationship can be written as:

\[
\text{max} \ (\text{EFFICIENCY}) = \text{max} \ (\text{TOTAL VALUE OF OUTPUT}) - \text{TOTAL VALUE OF INPUTS}.
\]

This equation simply calls for the difference between the two items on the right-hand side of the equation to be made as large as possible. The questions then become how the value of this equation can be measured objectively, and the appropriate pricing policy to bring about this result.

**Measuring the Total Value of Output**

Let us begin with the first term on the right-hand side of the equation, the total value of the output. How should we begin to evaluate how much the industry's output is worth? Clearly, the question must be answered with respect to how much value the consumers of the good or service attach to the output. Ford may have believed that it had developed a fine product in its Edsel, but as consumers did not want it, the value of the output to society was quite small.

One approach to the valuation question is simply to use the revenue figure corresponding to the quantity of the good demanded by consumers; that is, multiply the price of the good times the quantity. However, this measure understates the value customers derive from the good. Flat rate telephone or water service are perfect examples. In both these cases, having paid the monthly recurring charge for service, the customer can use all the additional calls or gallons he wishes at no additional charge. In other words, the incremental price for usage in both cases is zero. Thus, if we simply multiply price by quantity, we would get a value of zero. Clearly, this is not the case, so a slightly more sophisticated procedure is required.

The market demand curve is usually thought of as giving the relationship between the price of a good and the quantity of the good demanded. However, under very general conditions, it also represents the value that consumers place on the next unit of the good at any level of consumption. This is depicted graphically in Figure 1. In this figure, the demand curve is represented by the line labeled $D$. The demand curve tells us that the first unit of output is valued by consumers at an amount equal to $P(1)$; this is given by the shaded area in Figure 1. How much is the second unit of output worth to consumers? Once again, the demand curve shows us that the second unit of the good is valued at an amount given by $P(2)$; this is shown graphically by the hatched area in Figure 1. The third unit of the good in question has an incremental value given by $P(3)$, or the cross-hatched area in Figure 1. The values of the first three units of output, then, are obtained by summing the incremental values of each of the first three individual units; the shaded area plus the hatched area plus the cross-hatched area. We may continue summing such incremental valuations on down the demand curve until we reach the maximum quantity consumers desire to purchase given the price of the good. Let us suppose that the price of the good has been set at $P(*)$ in Figure 2. At $P(*)$ the demand curve shows that the quantity demanded...
will be equal to \( Q^* \). To find the total valuation placed on quantity \( Q^* \) by consumers, we add each incremental valuation up to \( Q^* \), shown graphically by the shaded area in Figure 2.

To make the example more relevant to the question of measured service, we may note that the incremental price of local telephone use is zero under a flat rate tariff structure. In this case, \( Q^* \) is set equal to zero in Figure 3, and the resulting quantity demanded is given by \( Q_{\text{max}} \). The point at which the demand curve intersects the quantity axis. In this case, the total value placed on the output (local telephone usage) by consumers given a price of zero is the entire area under the demand curve for local usage. Having found a way to determine the total value of the output, let us now turn to the second term on the right-hand side of our efficiency equation—the total value of the inputs used to produce the output.

**Measuring the Total Value of Inputs**

We face an analogous situation on the producer side of the market when attempting to measure the total value of the inputs used in producing any given level of output.

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**Figure 2. The Valuation of \( Q^* \) Units of Output**

**Figure 3. Output Valuation of Local Usage under Flat Rates**

As in the case of output valuation, if we simply multiply the quantity of inputs by their price, we may substantially over- or understate their true economic value. The former will be the case if the production process of the firm is characterized by diseconomies of scale; the latter will result if economies of scale are present in the production process. Thus, the procedure we will employ in evaluating this second term of the equation is similar to that used in measuring the value of the output.

The cost to the producer of making available the next unit of an economic good from any given level of output is reflected in the marginal cost function, labeled \( MC \) in Figure 4. In order to produce the first unit of output, the firm must utilize resources which have a value of \( C(1) \); this value is given by the shaded area in Figure 4. To produce the second unit of output, an additional amount of resources must be utilized. The incremental cost of providing this second unit of the good is graphically depicted in Figure 4 by the hatched area. The value of the resources used in producing the third unit of the good is given by \( C(3) \), the cross-hatched area in Figure 4. To find the total value of the inputs used to produce the first three units of output,
we simply add the incremental values of the first three units. In general, to find the total value of the inputs used to produce any specified level of output, for example, \( Q^*(i) \) in Figure 5, sum all the incremental values of all preceding units of output up to that level. Thus, in Figure 2 the total value of the inputs required to produce \( Q^*(i) \) is given by the shaded area under the marginal cost curve.

**Efficient Pricing Policy**

Having now established a metric by which the values of inputs and outputs can be measured, the task is to find the appropriate pricing policy which will make our measure of efficiency as large as possible. To do this, let us combine the graphs we used in assessing the output and input evaluations. In Figure 6 the demand and marginal cost curves are shown together. As shown earlier, the value that consumers place on that first unit of output is given by the height of the demand curve in Figure 6. Likewise, the cost to society from producing that first unit is measured by the area under the marginal cost curve. Given that the value to society of the first unit of output exceeds the value of the inputs used to produce that first unit of output, clearly, society is better off in aggregate to have that unit produced. In the case of the second unit, the incremental value placed on the output exceeds the value placed upon the inputs, so our measure of efficiency is increased by producing the second unit of output. We may continue for further units of output by comparing incremental values with incremental costs; if the incremental value placed on the next unit of output exceeds the incremental value placed on the resources used to produce that output, our measure of efficiency will increase.

As can be seen from an examination of Figure 6, for all units of output up to quantity \( Q(E) \), where the demand curve intersects the marginal cost curve, the incremental value placed on output exceeds the incremental value placed on the inputs. After quantity \( Q(E) \), however, the incremental value that society places on the resources used to produce the output exceeds the value that consumers place on having that further output. If production and consumption were to proceed beyond \( Q(E) \), then our measure of efficiency will be reduced. Thus, we can conclude that the appropriate quantity to produce of the good is \( Q(E) \). Since the demand curve tells us the price that will bring about the quantity demanded,
the appropriate pricing policy to maximize our measure of efficiency is to set the price equal to \( P(E) \), or price should be set equal to marginal cost. An appropriate measure of this efficiency is given by the shaded area in Figure 6.

**Applying the Model to Measured Service**

While the discussion has been largely carried on in generalities up to this point, there are no essential differences in applying this methodology to the appropriate pricing of local telephone services. Keeping in mind that under flat-rate tariff structures, the marginal price of a local call is zero, examine Figure 7. The demand curve of this figure is the same as in previous illustrations. However, for expository purposes and to be conservative, it is assumed that no economies or diseconomies of scale are evident in the production process. Thus, the \( MC \) curve in Figure 7 is shown as a horizontal line.

Under a flat-rate tariff, the resulting quantity of local usage demanded will be at \( Q(max) \) at a price of zero, \( P(0) \). The total value placed by consumers on this level of output will be the entire area under the demand curve. The total value of the inputs required to produce \( Q(max) \) units of local usage is given by the area under the marginal cost curve \( (MC) \) up to \( Q(max) \). The resulting efficiency measure at this quantity, however, is not as large as it could be. All usage to the right of \( Q(E) \) has a marginal valuation which is less than the marginal value of the resources consumed in providing that usage. By implementing a usage-sensitive pricing structure which sets prices equal to marginal costs, increases in efficiency would be possible. In Figure 7, the efficient price is designated \( P(E) \). The resulting gains in efficiency are illustrated by the shaded area to the right of \( Q(E) \)--the net difference between marginal value and marginal cost.

If a usage-sensitive pricing structure could be implemented at zero incremental cost, from the standpoint of economic efficiency, there is little doubt that it should be done. However, the ability to introduce usage-sensitive pricing requires that usage be metered and billed, a process which itself consumes productive resources. The interesting economic question then becomes: Do the incremental costs of metering local usage exceed the incremental gains to economic efficiency resulting from the imposition of positive
usage prices on local service?

Assume that the metering costs are strictly a function of usage and are equal to an amount \( m \) per unit of local usage. Under measured rates, the price per unit of local usage is set at the marginal cost of usage plus the marginal cost of metering. In Figure 8 this price is given by \( P(E) + m \). At this price, the resulting quantity demanded will be \( Q(E) \). The cost of metering this quantity of usage is determined by \( Q(E) \), the shaded area in Figure 8. An additional cost associated with the implementation of measured service must be accounted for as well. This is the deadweight loss associated with pricing above the marginal cost of production. In Figure 8 this cost is represented by the small dotted triangle between \( Q(E) \) and \( Q(D) \). The net efficiency gains of moving to measured service from flat rates can then be computed by calculating the gross efficiency gains (shaded area) less the metering costs (hatched area) less the deadweight costs (dotted area). If the resulting metric is positive, then implementing usage sensitive service is economically and socially justifiable. The magnitude of the gross efficiency gain depends upon both the elasticity of the demand curve and on the marginal cost of usage. Ceteris paribus, the greater the price elasticity of demand, the larger the gross efficiency gain will be. Likewise, ceteris paribus, the larger the marginal cost of usage, the greater the gain in gross efficiency will be. The magnitude of the deadweight loss depends upon both the price elasticity of demand and the marginal cost of metering, while the total cost of metering depends upon the quantity demanded and how the metering system is designed.

As a final note before turning to the quantification of these parameters, the standard we are using in this evaluation is much more restrictive than simply a comparison of the long-run cost savings potentially associated with measured service and the incremental costs of metering and billing. Referring to Figure 8, a measure of the annualized long-run production cost savings would be the area under the marginal cost curve between \( Q(N) \) and \( Q(max) \). While the fact that the increase in metering costs is more than offset by the reduction in flat rate production costs may be sufficient to justify measured service to the telephone company, it may not be a sufficient justification from the standpoint of appropriate public policy. Thus, in this paper, the more rigorous criterion of net economic efficiency is employed.

**Design and Cost Characteristics of a Measuring System**

There exist many potential ways to build a system capable of performing the measurement requirements inherent if one desires to implement a usage sensitive pricing structure. The system configuration ultimately adopted will depend in large measure on what the implementers wish to accomplish, both with measured service and other related programs. For example, with the advent of access charging, it might be least expensive to develop a measured service system that was not capable of concurrently handling a structure of access charges. Likewise, if a company is planning or currently performing remote polling of toll records, the measured service system should be designed to handle this requirement also.

It may be possible as well for an efficiently designed measurement system to substitute for other traffic engineering and usage study methods currently employed.

The measured service system (MSS) being designed and implemented by GTE has these abilities as well as others. In this section, the MSS will be described and the cost characteristics of the system will be explained.

**System Architecture**

The overall MSS system has five major subsystems: central office (CO); the communication links between the CO and a billing intermediate processor (BIP); the BIP itself; the communication links between the BIP and the data center; and the data center MSS functions themselves. The subsystems are shown in simple diagrammatic form in Figure 9.
At the CO the MSS equipment gathers billing information on each call and places it into a call record, which is stored. Periodically, a BIP "polls" its subordinate COs and requests that stored records be sent to it over the communications links. A BIP stores toll call records for subsequent transmission to the data center. The BIP "aggregates" the local call records by time and distance zones. Detailed local records may need to be retained in long-term storage under certain circumstances. The data center, in turn, polls its BIPs for call information, at which time toll call records and aggregated local records are transmitted for further processing and eventual billing to the customers.

Central Office. In electromechanical (EM) offices, MSS equipment is added "outboard" to the switching system. Monitoring is noninterfering so that any failure in the MSS equipment will not prevent calls from being completed. In stored program control (SPC) offices, the MSS functions are usually integral to the software of the switch itself and operate in conjunction with the call processing program.

Regardless of the technology of the central office, call data are collected for completed chargeable calls and placed in call records.

CO-to-BIP Data Links. The interface between a BIP and its COs is ordinarily an analog link operating synchronous full-duplex at data rates between 1,200 and 9,600 bps, inclusive. The rates are generally available within the continental United States, and analysis has shown that they are adequate to handle most present and planned traffic within GTE operating companies. 1,200 and 2,400 bps links can be dial-up or dedicated, while 4,800 and 9,600 bps links are ordinarily dedicated.

Digital 19.2 kbps links can also be used if data demands are extraordinarily high. When a BIP is co-located with the CO, a direct digital link will be used to convey commands and data between the CO and the BIP.

The BIP obtains call records from its COs by a technique called "delayed polling." With this method the BIP polls its COs periodically. The polling interval can vary with CO size and for an individual CO with the anticipated traffic load. Other conditions, such as recent link outages, can also affect the polling interval.

Billing Intermediate Processor. The BIP is a computer-based system that serves as a concentrator and prebilling processor located between the COs and the data center. Its functions include collection of call records from the COs, editing, separating into call classes (such as local or toll), aggregation of local calls into summary form, transmission of call data to the data center, and long-term retention of detailed local call records if required. Aggregation of local records into the summary record which is transmitted...
to the data center results in a data compression of about 40:1.

Each BIP normally services a number of COs with an average subscriber population range of 100,000 to 150,000. At a subscriber call rate of seven calls per day, a 100,000 line BIP will process 31.5 million call records a month.

Disk storage is provided for both short- and long-term call record retention at the BIP. The quantity of storage at the BIP is engineered from the minimal level required for supporting subscribers requesting local call records to the maximum, where all local records can be retained up to 180 days.

A BIP sends call records and other data upon data center request. Toll call records are requested daily. Aggregated long-distance records and selected detailed call records that are to be presented in the bill are requested on a billing cycle basis.

**BIP-Data Center Communications.** The data path from the BIPs to the data center is normally through dedicated transmission lines, although packet network circuits could be used. Adequate backup facilities for alternate routing of data in the event a critical line is congested or faulty should be provided. All communications transactions between the BIP and the data center are initiated by the data center.

**Data Communications Traffic Between the BIP and the Data Center.** Data communications traffic between the BIP and the data center includes bulk data and interactive support traffic using the HASP and 3270 protocols.

**Data Center.** The data center performs the functions of interfacing with the BIPs, preparing toll and local billing details, preparing subscriber bills, assisting in error correction, and performing billing administration functions. In those cases where companies are currently performing remote polling of toll records, the functions of the data center are essentially unchanged.

**Capital Costs of the MSS**

In describing the cost characteristics of this system, it would simplify matters a good deal if it were possible to state that the CO subsystem costs $x, the BIP and communications links cost $y, and the data center costs $z. It is not quite this simple. The MSS is a flexible system capable of being engineered by different telephone companies to suit their particular operations. For example, the cost of installing a BIP and its associated communication links depends upon the daily calling rate expected to be generated. This is because the BIP can be designed to handle a relatively low amount of traffic or a large amount, with resultant increase in initial costs. Likewise, in the case of the CO subsystem, the costs depend on the technology of the end office which is being converted to measured service.

With these considerations in mind, it is obviously impossible to state a priori exactly what the cost of implementing and operating the MSS will be unless the exact operating environment is specified beforehand. Accordingly, this section will provide a range of costs for the associated components of the system and will specify a "most likely" typical configuration cost. For expository purposes, we will first detail the start-up, nonrecurring capital costs of the system and then examine the ongoing costs of operation.

**Central Office Subsystem Costs.** The costs associated with the CO system depend on the type of technology employed in each particular end office. In an electromechanical (EM) office, the MSS equipment consists of an outboard device designed to gather usage data. The equipment is connected internally to the existing central office equipment at a point of concentration without interfering with any type of central office operation.

Within the EM subsystem, the design concepts permit the flexibility of remote office operation. The system is designed in 10,000 line modules capable of operation with the main processor over dial-up or dedicated modems. This concept provides remote operation of small offices on a combined basis to a centrally located main/standby processor. The number of offices that can be served by the main/standby processor on a remote basis is limited only in that the total lines of the remote offices must not exceed 10,000 lines. Any office can be the host office for locating the main/standby processor.

Each 10,000 line system costs $30,000 + $800 per line. Thus, for an 8,000 line EM configuration, the cost would be $30,000 + $64,000 = $94,000. If a 12,000 line configuration were required, the cost would be:

- $ 30,000 for the first 10,000 lines
- $ 30,000 for the second 10,000 lines
- $ 8*12,000 for the 12,000 lines
- $ 196,000 for 12,000 EM lines

Unlike the case of EM offices, in stored program control (SPC) offices the measurement functions are integral to the software of the switch itself and operate in conjunction with the call processing program. SPC switch changes consist of modifications to the software resident within the various switches to output call data for all local and toll calls and a replacement recording subsystem (polling interface) which provides for electronic data transfer to the BIP. In addition to data storage, the PI will provide the communications interface to the BIP. Data are stored by the PI in logical files on a disk until polled by the BIP. The PI interfaces with the SPC switch by means of redundant data channels. In the event of data channel failure between the
SPC switching system and the PI, or if the PI storage capacity has been reached, the MSS system will default to recording on the SPC switch magnetic tape back-up system. The SPC configuration is shown in Figure 10.

The price to the telephone company for modifications to the call processing software ranges from approximately $15,000 in the newest digital switches to approximately $50,000 in older generation SPC switch types being considered for conversion to MSS. The nominal hardware cost of the polling interface is approximately $40,000. However, in most current SPC switches, at least two magnetic tape drives are used for AMA and other purposes. Since the PI device is a substitute for at least one of these tape drives, the actual incremental cost of purchasing the PI is reduced to approximately $25,000.

Unlike the case of the EM subsystem, where SPC technology is involved there is no additional cost per line. Once an office has been equipped for message recording, all lines in that office have the capability of being measured. In the host/remote SPC switching arrangement, the SPC subsystem can accommodate up to 180,000 lines.

Within each CO subsystem, there is an additional cost to the Telco for initial installation and testing. This imposes an additional 15 percent increase on the purchase price for an installed CO subsystem.

BIP and Communication Link Costs. As its name implies, the BIP serves as an intermediary between the call records generated at the switches and the billing systems on the host mainframe. Using dial-up lines or dedicated circuits, detailed call records are polled from the COs under control of the BIP. After the local records have been aggregated at the BIP, the resulting information is polled under control of the host mainframe using dedicated circuits. The BIP is designed to be run in an unmanned mode and will be able to be operated with a very high degree of reliability. BIP polling will replace the present physical transport of toll information in all but rare cases where switch or CO-BIP communication problems cause the switch to invoke the tape back-up recording mode. Thus, there will be fewer media problems (bad or lost tapes) and an improvement in cash flow as billing of toll records should be quicker.

The cost of a BIP and associated communication links depends on a combination of the number of end-user access lines and the daily calling rate per line, including both local and toll. This is because the BIPs can be engineered to handle different operational requirements.

The figures below show the approximate first cost of a BIP and its associated communications links. Calls per day include both local and toll calls.
<table>
<thead>
<tr>
<th>BIP size (calls/day)</th>
<th>Initial purchase price</th>
</tr>
</thead>
<tbody>
<tr>
<td>175,000</td>
<td>$243,000</td>
</tr>
<tr>
<td>250,000</td>
<td>$338,000</td>
</tr>
<tr>
<td>600,000</td>
<td>$600,000</td>
</tr>
<tr>
<td>1,000,000</td>
<td>$775,000</td>
</tr>
<tr>
<td>1,400,000</td>
<td>$920,000</td>
</tr>
</tbody>
</table>

If the calling rate in the COs served by the BIP is seven calls per day, then a $500,000 BIP will service 100,000 lines. If the calling rate were, instead, three calls per day per line, then the lines which can be handled by the same BIP would be more than double. Actual BIP sizing and deployment would be based on the traffic and customer characteristics of the COs the BIP would serve in each telephone company. Just as in the case of CO subsystems, there is an additional cost to the telco to install and test a BIP. This additional cost is approximately 2 percent of purchase price.

**Ongoing Incremental Budgetary Costs**

**Associated with Measured Service**

Investment in measuring equipment is by no means the only cost associated with local measured service. The costs of usage processing and billing subscribers will also increase. Corporate comptrollers will generally be responsible for making the adjustments to accounting records which are required by local measured service. Specialized analysis programs and other billing modifications to the customer records and billing system must also be developed. Many of these costs represent initial start-up costs, and some may be spread over all exchanges where they are shifting to measured rates. Once these adjustments are made, however, there will nevertheless remain a continuing added expense for message processing.

Some current studies of local traffic reveal multiples of up to fifteen times present toll volume, depending on the size and the amount of extended area service (EAS) available to the subscribers. Whether billing systems are built into the measuring equipment or downstream in the data processing system, considerable computer power and time are required. To provide measured local service, appropriate and adequate computer facilities will be required in billing centers. Or, processor-oriented recording equipment may be more efficiently used as preliminary rating tools, as in the case of the MS.

Another consideration is the cost and efficiency of centralized versus distributed (localized) rating and billing. Moreover, the retention of these huge volumes of data can be quite costly, particularly if full detail (as opposed to bulk detail) of all local calls is required on the customer’s bill or is provided in the event of customer inquiries. Customer and financial accounting records and reporting systems will require alteration to provide for measured local and related services. The prime consideration, aside from direct cost, in this aspect of providing measured service is the time involved in implementing these data processing changes. Tariff design for LMS depends greatly on the telephone company’s capacity to process and maintain such volumes of information; conversely, the time and dollars involved with the design, programming, and thorough testing of rating and billing systems can be crucially dependent on the complexity of the recorded data and rating procedure.

Even prior to the rating phase, other considerations become important. For example, consider a measured service exchange normally generating 60,000 toll messages per month; the 15:1 ratio would predict 900,000 local billable messages, or 960,000 total billable calls per month. These 32,000 messages/day would require nearly one hour/day for transmission to a billing center over a 4.800 bps data channel. To have back-up copies of the data might require additional transmission. Also, of course, the simple transmission of data is compounded by the number of exchanges within a given company whose local usage is measured. Given the various configurations possible with the MS, the cumulative monthly cost for processing local traffic (data transmission, editing, analysis, rating, and billing) is in the neighborhood of $0.0015 to $0.008 per local call.

The effect of measured rates on the costs of maintaining good customer relationships cannot be ignored. LMS is likely to engender an increased volume of inquiries and complaints directed to the company’s local business office. In an effort to provide the subscriber with assistance and information, the business office will be required to retain existing personnel in preparation for a measured rate environment and to maintain readily accessible consumer billing records. Moreover, subscribers initially electing measured service may change service in an optimal environment, while flat rate subscribers might eventually forsee savings under measured rates. From another viewpoint, the telephone company may provide additional "service" by assisting business and residential subscribers alike in opting for the service most suitable to their needs; in particular, business customers whose usage is great may require more facilities or even different services entirely. With wages alone accounting for nearly 75 percent of business office expense, increased cost could be considerable in this sector of telco operations.

The ongoing costs associated with the business office function are estimated to range from $0.001 to $0.0025 per local message depending on the complexity of the tariff. There are many variables to be considered besides manpower.
when considering costs for telco contacts with its customers: record-keeping facilities (computer storage, microfiche access to records, credit voucher systems, calling detail provided to the customer on his bill), toll-pay procedures, cash flow, payment procedures and records for excessive subscriber bills, more timely record-keeping regarding service connection and disconnect, and so forth. Moreover, the business office and telco marketing departments may find it necessary to work closely with high use subscribers, both residential and business, to assist them in controlling their telephone bills and making certain their equipment is cost effective and/or adequate for their needs. They will be concerned also that appropriate advertising campaigns are available to protect these high-use customers and to counter cautionary advertising regarding peak loads (as in the power industry).

Effective public relations will also require company efforts to educate and inform its subscribers prior to the implementation of MSS. Bill stuffers, media advertising, dual billing, and direct customer contact are a few of the methods by which the company will incur expenses in preparation for the implementation of measured rates.

Ongoing expenses, at least for the first several years of measured service, depend on the tariff complexity and the precise mix of public relations methods employed. These costs are included in the business office expenses.

In addition to the business office, LMS is likely to place additional demands on local operator services. Local assistance calls, such as calls for rate and credit requests, may increase in a measured rate environment. Furthermore, credit, collect, third party, and other calls requiring operator assistance may be demanded for local as well as toll calls. In this latter instance, surcharges on toll operator assistance must be explored as a method of curtailing demand and placing the remaining cost of this service squarely on the cost cause. Telephone operators will experience customer inquiries regarding call placement assistance, directed calls, directory assistance, and complaints. The manpower, floor space, and operator equipment needs can be a major cost for local switching companies.

Maintenance of customer equipment and circuits has always been important but now it becomes key. Through training is essential on the procedures necessary in the diagnosis and maintenance of CU equipment, outside plant, and recording

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**Summary of Incremental Investments and Expenses**

This section has explored the relationships between local measured service and the incremental investments and expenses incurred by the telephone company. Measured service will require investment in measurement equipment, development, and modifications of customer billing programs. Expenses will be incurred to prepare and inform the public for a measured rate environment, to maintain sound public relations, to train company personnel, and to process and bill the local records.

To place these figures in a form more easily recognizable, it might prove convenient to express the investment dollars in terms of first cost per line converted to measured service. In order to do this, however, it is necessary to describe briefly the operating environment of the telephone company. At the time of conversion to measured service, the company will be serving 435,000 lines out of 35 central offices. Of these lines, 355,500 are residence lines, the remainder business lines. Customers make a weighted average of 6.4 calls per day as follows:

- **Calls per line or trunk**
  - R1: 5.6 calls per day
  - B1: 9.4 calls per day
  - Key: 7.8 calls per day
  - P/BX: 15.4 calls per day

The central offices combine a mix of technologies; 20 percent are SPC analog units, 20 percent are EM units, and 60 percent are digital base or remote units. Approximately 60 percent of the lines are served from digital offices, 30 percent from SPC analog offices, and 10 percent from EM offices. The distribution of offices and lines is thus:

<table>
<thead>
<tr>
<th>Technology</th>
<th>Offices</th>
<th>Lines</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPC analog</td>
<td>7</td>
<td>269,800</td>
</tr>
<tr>
<td>EM</td>
<td>7</td>
<td>43,300</td>
</tr>
<tr>
<td>Digital</td>
<td>21</td>
<td>259,800</td>
</tr>
</tbody>
</table>

Given this operating arrangement, the resulting per line initial capital costs are given in Table 1 for the CU subsystem components.
<table>
<thead>
<tr>
<th>Table 1. CO Subsystem Initial Capital Costs/Lime</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electromechanical</strong></td>
</tr>
<tr>
<td>5 units of 10,000 lines @ $30,000 = $150,000</td>
</tr>
<tr>
<td>43,000 lines @ $1.00 = $43,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
</tr>
<tr>
<td>$193,000</td>
</tr>
<tr>
<td><strong>SPC Analog</strong></td>
</tr>
<tr>
<td>7 units - software modifications @ $35,000 = $245,000</td>
</tr>
<tr>
<td>7 Polling Interfaces @ $40,000 = $280,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
</tr>
<tr>
<td>$525,000</td>
</tr>
<tr>
<td><strong>SPC Digital</strong></td>
</tr>
<tr>
<td>11 base units - software modifications @ $15,000 = $165,000</td>
</tr>
<tr>
<td>11 Polling Interfaces @ $25,000 = $275,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
</tr>
<tr>
<td>$440,000</td>
</tr>
<tr>
<td><strong>Incremental capital costs</strong></td>
</tr>
<tr>
<td>$1,461,400</td>
</tr>
<tr>
<td>+ Incremental installation costs</td>
</tr>
<tr>
<td>219,210</td>
</tr>
<tr>
<td>Lines equipped for measured service</td>
</tr>
<tr>
<td>43,000</td>
</tr>
<tr>
<td><strong>Incremental capital costs/lime for CO subsystem</strong></td>
</tr>
<tr>
<td>$3,960</td>
</tr>
</tbody>
</table>

The call handling capacity is equivalent, but each BIP now serves fewer lines. If a three-BIP configuration is employed, the resulting initial cost per line is $4.92.

On the ongoing expense side, there is also a range of potential costs. For purposes of convenience, these may be stated in terms of dollars per call. Both the low and high values are shown as follows:

<table>
<thead>
<tr>
<th>Services</th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data processing</td>
<td>$0.0015</td>
<td>$0.0080</td>
</tr>
<tr>
<td>Bus. office &amp; p.a.</td>
<td>$0.0010</td>
<td>$0.0025</td>
</tr>
<tr>
<td>Operator services</td>
<td>$0.0004</td>
<td>$0.0030</td>
</tr>
<tr>
<td>Maintenance</td>
<td>$0.0000</td>
<td>$0.0060</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$0.0019</td>
<td>$0.0095</td>
</tr>
</tbody>
</table>

Total ongoing incremental expenses associated with measured service thus range between one-half a mill per message ($0.0005) and almost two mills ($0.002) per message processed. A reasonable point estimate would be in the neighborhood of one mill ($0.001) per message processed.

**Estimates of Price Elasticity of Demand for Local Usage**

With one piece of the efficiency puzzle in place, we now turn our attention to a second piece, the sensitivity of the quantity of local usage demanded to changes in the price of local usage. The measure customarily used for this purpose is the price elasticity of demand, defined as the percentage change in quantity demanded resulting from a one-percentage change in price. This section will offer no new statistical results but instead will briefly summarize the existing literature as to the magnitude of the price elasticity of demand for local telephone usage.

As pointed out earlier, the price elasticity of demand plays a key role in determining the overall net efficiency of moving from a flat rate to a measured rate pricing structure. Generally speaking, the greater the price elasticity of demand, the larger the gain from usage sensitive pricing will be. Figure 11 presents a summary of elasticity estimates from researchers who have dealt with the problem of analyzing the demand for local telephone service. The estimates are based on a range of statistical techniques and data sources. Some employed Box-Jenkins analysis (Wilkens and Janski, while others used more traditional econometric techniques (Beauvais and Doherty). Considering
the range of data sources and techniques employed, the resulting estimates are remarkably close. All show local usage to be inelastic and relatively low. Based on a judgmental synthesis, the white area in Figure 11 illustrates the overall range in which the usage elasticity falls for residential customers. Numerically, the anticipated range is from -.05 to just over -.2.

In Figure 12, elasticity estimates are presented for business customers, while fewer studies address the business customer as a class, those available indicate a price elasticity of demand roughly in the same range as residential customers. Once again in this figure, the range in which the usage elasticity may be expected to fall for business customers is indicated by the white region of the line. It ranges from approximately -.05 to just under -.2.

For both residence and business demand for usage, it appears that calls are somewhat less elastic than minutes of use and that usage during the peak period is more inelastic than usage in off-peak periods. The latter situation is

Figure 11. Estimates of Price Elasticity of Local Usage (Residential Customers)

Figure 12. Estimates of Price Elasticity of Local Usage (Business Customers)
similar to results found by researchers into the time-of-day characteristics of electricity demand.

Estimates of Long-Run Marginal Costs of Telephone Usage

A number of telephone company and academic studies are available which estimate the long-run marginal costs of telephone service. The magnitude of these costs is important, since they determine the potential costs which can be saved by moving to a measured rate structure.

One of the earlier studies is that of S.C. Littlefield and J.J. Rousseau. Their study utilized 1967 data for Illinois Bell Telephone Company to estimate that company's long-run marginal costs. A nonlinear mathematical programming model was used to calculate marginal costs on each of three representative routes in each of four time-of-day pricing periods. The three routes were Midland, Chicago-Peoria, and Chicago-Champaign. The time-of-day periods were: (1) day (6 a.m. - 9 p.m.); (2) evening (9 p.m. - 11 p.m.); (3) night (11 p.m. - 6 a.m.); and (4) after midnight (6 a.m. - 8 a.m.).

For present purposes, the Illinois study results are reproduced (in part) below. All prices are in cents per three-minute call in 1967 dollars.

<table>
<thead>
<tr>
<th>Period</th>
<th>Long-run marginal costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day</td>
<td>$.02</td>
</tr>
<tr>
<td>Evening</td>
<td>$.01</td>
</tr>
<tr>
<td>Night</td>
<td>$.01</td>
</tr>
<tr>
<td>After midnight</td>
<td>$.01</td>
</tr>
</tbody>
</table>

A more recent study has been conducted by Jeffrey Rohrs of Bell Labs. He makes use of data for the entire Bell System for 1972-1975 to estimate marginal costs. His approach was to look at historical data and relate changes in annual costs to annual changes in output. In doing this, he controlled for factors (such as inflation) that would otherwise have caused costs to change apart from changes in output. Rohrs' results are shown in Table 2. While his methodology does not provide for time-of-day differences in marginal costs, it does add important estimates of the cost of access.

On the basis of his weighted average for the period, the monthly marginal cost for access alone would have been $10.83 per month, exclusive of all usage.

Remaining within the Bell System, another estimate of long-run marginal costs can be obtained from Southwestern Bell's latest filing in Missouri. Utilizing 1982 data, SW Bell simulated the change in costs associated with a change in the demand for its services. The results are presented in Table 3. The SW Bell estimates add two items of information to the analysis of marginal costs. First, estimates are provided independently for both the cost of establishing a connection (set-up) and for maintaining that connection (duration). It can be seen that the cost of maintaining the connection of a call is significantly different from zero except for the night period, where conversation minutes can be provided at a zero incremental cost, even in the long run. Second, the SW Bell estimates show that the marginal costs of network usage increase with the length of haul.

Table 2. Annualized Marginal Cost Estimates Based on Historical Data

<table>
<thead>
<tr>
<th></th>
<th>Access</th>
<th>Local usage</th>
</tr>
</thead>
<tbody>
<tr>
<td>1972-74 change</td>
<td>$100</td>
<td>$.026</td>
</tr>
<tr>
<td>1974-75 change</td>
<td>$110</td>
<td>$.040</td>
</tr>
<tr>
<td>Weighted average (1973-1975 change)</td>
<td>$130</td>
<td>$.030</td>
</tr>
</tbody>
</table>

Table 3. Southwestern Bell Estimates of Marginal Costs, Missouri

<table>
<thead>
<tr>
<th>Mileage band</th>
<th>Day</th>
<th>Evening</th>
<th>Night</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-14</td>
<td>$0.0216</td>
<td>$0.0198</td>
<td>$0.0271</td>
</tr>
<tr>
<td>Duration</td>
<td>0.0664</td>
<td>0.0035</td>
<td>-</td>
</tr>
<tr>
<td>15-28</td>
<td>$0.0277</td>
<td>$0.0154</td>
<td>$0.0271</td>
</tr>
<tr>
<td>Duration</td>
<td>0.0135</td>
<td>0.0073</td>
<td>-</td>
</tr>
</tbody>
</table>

Note: All figures are stated in 1982 dollars.
At least one non-Bell company has made some estimates of its level of long-run marginal costs. In a preliminary study of GTE systemwide data over the period 1975-1980, PNR Associates utilized econometric techniques to estimate the long-run marginal costs of both access and usage for GTE. The cost function was estimated for three output categories: customer access, local usage, and toll usage. In these preliminary estimates, no refinements were made for considerations of time of day or length of call, or for separating the costs of set-up versus duration. Thus, usage cost estimates represent the marginal cost of a typical local call (approximately 4 minutes) weighted for time-of-day and distance considerations. The marginal cost estimates are presented below:

<table>
<thead>
<tr>
<th>Access</th>
<th>Local usage (per call)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 30.17</td>
<td>$.058</td>
</tr>
</tbody>
</table>

The results of the initial PNR estimates suggest that the nominal costs of providing both access and usage have increased substantially during the past decade. This should come as no surprise given that since 1967 the Consumer Price Index rose 115 percent, from 100 in 1967 to 245 in January 1983.13 Telecommunications costs: indices indicated only a slightly better performance, rising from 100 in 1967 to 155 in January 1983.13 To put these figures in perspective, they should all be placed on a constant dollar basis. Using the Hendy-White index, a summary of the estimates of long-run marginal costs of a four-minute call,14 weighted for time-of-day and distance characteristics adjusted to 1982 dollars,15 is as follows:

<table>
<thead>
<tr>
<th>L-R</th>
<th>Rohrsf</th>
<th>SW Bell</th>
<th>PNR</th>
</tr>
</thead>
<tbody>
<tr>
<td>$.049</td>
<td>$.058</td>
<td>$.055</td>
<td>$.068</td>
</tr>
</tbody>
</table>

Similar adjustments are required to the two studies which reported estimates of the long-run marginal cost of access. Stated in 1982 dollars, the marginal cost of access (excluding OPE) per line/month from the Rohrsf study is $21.06. From the PNR results, the corresponding figure is $29.90. Rather than providing a definitive answer, which is impossible, the foregoing review of the scant literature available gives a range of cost estimates which may serve as a guide to reasonableness. These cores of reasonableness are as follows:16

- Monthly access: $21.00 - $30.00
- "Typical" call: $0.05 - $0.075
- "Premium" call: $0.10 - $0.075
- "Off-peak" call: $0.02 - $0.035

For pricing purposes, it is mandatory to disaggregate these costs into individual components by rate element. The relevant rate elements for immediate purposes may be defined as call set-up and duration on the usage side and network access. The latter may be defined quite simply as the opportunity for a customer to originate and receive telephone calls, be they intraexchange, interstate, or interstate, independently of his actually doing so. A call set-up is the establishment of an end-to-end connection between the originating party and the terminating party and contains no element of duration. Duration is defined as the time elapsed between the off-hook condition of the called number and the subsequent circuit disconnection by either party.

Table 4 provides a summary of the results obtained from a recently completed long-run marginal cost study by a GTE telephone operating company, which will be referred to as General Telephone Company of Sanpale. To be consistent, these long-run marginal cost study results are reported for the same company used in characterizing the magnitude of the metering costs earlier. By comparing the results contained in Table 4 with the zones of reasonableness reported above, it can be seen that General Telephone of Sanpale is operating at a lower end of the usage bands and is squarely in the middle in terms of the marginal cost of network access. This is illustrated graphically in Figure 13. The figures in the boxes represent the costs of GTO.

When taken together, these studies indicate that there is indeed a long-run marginal cost of telephone usage. Despite the different data sources and methodologies employed in arriving at the estimates, all the studies indicate a relatively narrow range of reasonableness in which the costs may be expected. The estimates themselves, however, are point estimates and do not indicate the range of the marginal cost function. Given the time periods over which the studies were conducted and the different company sites studied, it would appear to be a warranted and conservative assumption to expect that the production function for telephone usage exhibits constant returns to scale.

Calculations of Changes in Economic Efficiency

At this point, sufficient information has been accumulated to calculate the net change in economic efficiency associated with converting to a measured rate structure from flat rates. In this section, such calculations will be made following the methodology outlined earlier. First, a base case will be established utilizing the data outlined previously for General Telephone Company of Sanpale (GTS). Next, sensitivity analyses will be conducted to test the robustness of the results derived in the base analysis.
Figure 13. Comparison of GTS Cost Study Results with Other Study Results

<table>
<thead>
<tr>
<th></th>
<th>$21</th>
<th>$22</th>
<th>$23</th>
<th>$24</th>
<th>$25</th>
<th>$26</th>
<th>$27</th>
<th>$28</th>
<th>$29</th>
<th>$30</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rolsifs</td>
<td>$21.06</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PNR</td>
<td></td>
<td>$24.97</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$29.90</td>
</tr>
</tbody>
</table>

**Typical Call**

<table>
<thead>
<tr>
<th></th>
<th>$0.04</th>
<th>$0.045</th>
<th>$0.05</th>
<th>$0.055</th>
<th>$0.06</th>
<th>$0.065</th>
<th>$0.07</th>
<th>$0.075</th>
</tr>
</thead>
<tbody>
<tr>
<td>L-R</td>
<td>$0.04</td>
<td></td>
<td>$0.049</td>
<td>$0.055</td>
<td>$0.058</td>
<td>$0.068</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Peak Period Call**

<table>
<thead>
<tr>
<th></th>
<th>$0.04</th>
<th>$0.045</th>
<th>$0.05</th>
<th>$0.055</th>
<th>$0.06</th>
<th>$0.065</th>
<th>$0.07</th>
<th>$0.075</th>
</tr>
</thead>
<tbody>
<tr>
<td>SWBell</td>
<td>$0.052</td>
<td></td>
<td></td>
<td>$0.0649</td>
<td></td>
<td>$0.0735</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Off-Peak Period Call**

<table>
<thead>
<tr>
<th></th>
<th>$0.01</th>
<th>$0.015</th>
<th>$0.02</th>
<th>$0.025</th>
<th>$0.03</th>
<th>$0.035</th>
<th>$0.04</th>
<th>$0.045</th>
</tr>
</thead>
<tbody>
<tr>
<td>L-R</td>
<td>$0.019</td>
<td>$0.0245</td>
<td></td>
<td>$0.030</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**GTS serves 433,000 lines, 355,000 residence lines, and 77,500 business lines (38,045 R1 lines, 29,385 Key Lines, and 10,070 PBX lines). The main annual calling rates per line differ significantly by class of service and by time of day and class of service. Table 5 summarizes these annual calling rates. These numbers are taken from a recently completed usage study conducted by the telephone company. The last line of Table 5 also gives the flat rates applicable to each class of service, ranging from almost $11.00 per month for R1 customers to almost $50.00 per month per trunk for a PBX customer.**

In designing its measured service rate structure, it is assumed that the telephone company's revenue objective is to recover approximately the same total revenues as it currently receives under flat rates plus the incremental revenue requirement associated with the metering system. To do this, it sets the usage prices equal to the marginal costs of usage plus the marginal metering cost per message. The monthly recurring access charge then becomes the residual...
amount necessary to meet the revenue requirement, much as
it is currently. In Table 6 the resulting usage prices are
given by time of day. The same usage rates apply to all
classes of service. The marginal costs are obtained from
Table 4, and the incremental cost of metering ($0.01) is
obtained from the earlier cost analysis. Note that the incre-
mental cost of metering usage is applicable only to call
set-up; that is, the incremental costs of call measurement
are approximately independent of the duration of any call.
As a result of customers being confronted with positive
incremental prices for local usage, it can be anticipated
that the quantity of local usage demanded will decrease.
The magnitude of this reduction depends on the elasticity
of demand. For GTS, the arc price elasticities for each
component of usage are given below.

<table>
<thead>
<tr>
<th>Residence</th>
<th>Peak</th>
<th>Off-peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Set-up</td>
<td>-.08</td>
<td>-.1</td>
</tr>
<tr>
<td>Duration</td>
<td>-.10</td>
<td>-.15</td>
</tr>
<tr>
<td>Business</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Set-up</td>
<td>-.05</td>
<td>-.07</td>
</tr>
<tr>
<td>Duration</td>
<td>-.10</td>
<td>-.12</td>
</tr>
</tbody>
</table>

The arc price elasticities are used since in the present
context we are not dealing with infinitesimally small changes
in prices, but rather a major restructuring of local telephone
prices. Note that the price elasticities of demand for busi-
ness customers are somewhat less than for those of residence
customers, and that peak period demand is less elastic than
that in the off-peak period. If these estimates are compared
to those given earlier, it will be noted that they are broadly
consistent and lie in the lower end of the likely range,
both for residence and business.

At the price set specified in Table 6 and using the
matrix of arc elasticities given above, the new usage levels
after the introduction of measured rates are given in Table
7 in the columns labeled Q(m). For comparison purposes,
the previous flat rate usage is given under the column labeled
Q(f). Additional columns labeled Q(mc) are also provided,
indicating what the quantity of local usage demanded would
have been had prices been set equal to marginal costs not
including the incremental costs of metering. Since the cost
of metering is approximately independent of the duration
of the call, the two columns Q(m) and Q(mc) under the "Minutes
of Use" categories are equivalent. Graphically, the quantities
Table 7. Comparison of Local Usage under Flat Rates, Measured Rates, and Strict Marginal Cost Rates (Mean Annual Usage/Line)

<table>
<thead>
<tr>
<th>Call set-ups</th>
<th>Minutes of use</th>
<th>Q(f)</th>
<th>Q(m)</th>
<th>Q(mc)</th>
<th>Q(f)</th>
<th>Q(m)</th>
<th>Q(mc)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Peak Period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R1</td>
<td>1,416</td>
<td>1,206</td>
<td>1,215</td>
<td>3,828</td>
<td>3,132</td>
<td>3,132</td>
<td></td>
</tr>
<tr>
<td>B1</td>
<td>2,544</td>
<td>2,301</td>
<td>2,311</td>
<td>4,972</td>
<td>3,986</td>
<td>3,986</td>
<td></td>
</tr>
<tr>
<td>Key</td>
<td>2,632</td>
<td>2,291</td>
<td>2,301</td>
<td>5,004</td>
<td>4,094</td>
<td>4,094</td>
<td></td>
</tr>
<tr>
<td>PBX</td>
<td>4,512</td>
<td>4,082</td>
<td>4,099</td>
<td>9,384</td>
<td>7,678</td>
<td>7,678</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Off-Peak Period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R1</td>
<td>600</td>
<td>491</td>
<td>500</td>
<td>1,644</td>
<td>1,215</td>
<td>1,215</td>
<td></td>
</tr>
<tr>
<td>B1</td>
<td>840</td>
<td>730</td>
<td>739</td>
<td>1,716</td>
<td>1,348</td>
<td>1,348</td>
<td></td>
</tr>
<tr>
<td>Key</td>
<td>276</td>
<td>240</td>
<td>243</td>
<td>684</td>
<td>527</td>
<td>527</td>
<td></td>
</tr>
<tr>
<td>PBX</td>
<td>1,056</td>
<td>918</td>
<td>929</td>
<td>2,496</td>
<td>1,961</td>
<td>1,961</td>
<td></td>
</tr>
</tbody>
</table>

Q(f), Q(m), and Q(mc) are shown in Figure 14 aggregate over all residence customers. Panel (a) is for peak period set-ups per year; panel (b) is annual peak period minutes of use; panel (c) shows annual off-peak set-ups; and panel (d) illustrates total annual off-peak period minutes of use for all residence customers. Similar illustration could be drawn for other classes of service but to conserve space they are omitted.

Following the methodology given in the first section, the shaded areas on each panel of Figure 14 represent the gross efficiency gains from residence customers derived from implementing measured rates. The hatched areas represent the ongoing usage measurement costs associated with residence customers’ usage. The small dotted triangles in panels (a) and (c) are the deadweight losses associated with pricing in excess of marginal costs.

Table 8 translates these graphical representations into dollar estimates of the magnitudes of these costs and benefits, not only for R1 customers but also for the other classes of customers. Within each class of service, the gross efficiency gains are summed and the incremental metering costs and deadweight costs are subtracted to arrive at the net efficiency gain prior to the consideration of capital costs associated with the measurement system. For each class of service, as shown by the last line in Table 8, the net increment.

mental gain from moving to measured service is positive. For the company as a whole, the net efficiency gain is $1,792,370 annually. It is important to note that this is not a one-time gain, but an ongoing annual benefit from the introduction of measured rates.

The net efficiency gain just calculated must still be adjusted to account for the initial capital costs incurred to establish the measured service billing system. With GTS serving 433,000 customers, the aggregate net efficiency gain translates into a net gain of $4.14 per line per year. Assuming an annual charge factor of .25, this means that GTS can spend a maximum of $15.55 per line first cost before the efficiency gains from MSS are depleted. However, we know that the initial capital cost per line is only $8.40 for GTS. Utilizing the same annual charge factor of .25, GTS’s first capital cost per line becomes $2.10 on an annual basis or $0.10 per month per line. In this base case then,
the annual adjusted net efficiency gain from moving to measured rates is $4.14 less $2.10, or $2.04 per line per year. To complete the base case view, the resulting residual network access prices are compared to former flat rate prices, assuming the company wants to keep the proportion of revenue derived from each class of service approximately the same before and after the introduction of measured rates. This information is presented in Table 9. As a result of instituting measured rates, each customer class enjoys a substantial reduction in the network access charge from the current flat rate level. This is true even after the incremental capital costs of the metering system are accounted for, as they have been in Table 9.

The base case analysis strongly suggests that the institution of measured rates is justified under the criterion of economic efficiency. After accounting for all costs associated with metering, both initial and ongoing, the net gain to society is approximately $2.00 per line annually. While the figure is not overwhelmingly large, it does represent the freeing up of resources which can be used for other purposes. At the same time, the reduction in network access charges will help sustain the concept of universal service over time.

It is also interesting to compare the net gains in economic efficiency to the potential cost savings derived from measured rate service. The net efficiency gains from instituting US$ are significantly less than the cost savings associated with measured rates. If the reader will recall the model description, it was stated that the criterion of economic efficiency was a much more stringent criterion than that of simple cost reductions. To see how much more stringent, the long-run cost savings can be calculated from the information provided in Table 8. The unadjusted long-run cost savings from reducing the quantity of usage demanded are approximately double the gross efficiency gains. Total gross efficiency gains are $2,639,559 annually. Doubling this number yields $5,279,118 per year in potential cost savings.

| Table 9. Flat Rate Versus Measured Rate Network Access Charges by Class of Service |
|---------------------------------|-----------------|-----------------|-----------------|-----------------|
|                                | R1              | B1              | Key             | PBX             |
| Current flat rate              | $10.90          | $29.85          | $37.90          | $48.95          |
| Measured rate                  | $6.05           | $21.95          | $30.56          | $34.87          |
savings. However, in order to achieve this reduction, it is necessary to incur the measurement costs, both capital and expenses. The annual metering expenses from Table 8 are $847,108; annualized capital costs are $2.10 per line, or $2,500 annually. Netting these figures out of the $5,279,118 produces an annualized long-run cost savings of $3,522,630. On a per line basis, this translates to an annualized cost savings of $8.14 per year. While the efficiency gains are on the order of $2.00 annualized, the cost savings are more than four times greater.21

**Sensitivity Analysis**

In a sense, the base case parameters almost represent a worst-case analysis—the price elasticities are toward the lower end of the likely range; the marginal costs of usage are equally low in their likely range. The incremental cost of metering, however, is only at the midpoint of its expected range in the base case. Thus, the first sensitivity tests will be on the ongoing incremental costs of metering, keeping all other parameters constant.

Table 10 illustrates the trade-off between the ongoing expense per message and the maximum first cost per line for measurement equipment beginning at $0.000 and going to $0.002 per message. The likely range given in an earlier section is indicated by the dashed lines. Keeping in mind that GTS's installed first cost is $8.40 per line, all figures within the likely range indicate a positive gain in efficiency. However, at the upper end of the likely range, the efficiency gains are minimal. All other things equal, ongoing expenses above $0.00195 per message result in efficiency losses.

Two additional levels of ongoing expenses are presented in Table 10: $0.00 and $0.002. The former is interesting since it suggests that even if ongoing incremental expenses associated with measured service were zero, there still exists a maximum installed first cost which cannot be exceeded, in this case $25.00 per line. The latter is of interest since it is purported to be the actual ongoing metering cost of New York Telephone Company.20 Clearly, this figure is far outside the range reported earlier, and equally obvious is the result that at such a cost the implementation of measured rates for local usage would lead to substantial efficiency losses. However, given the metering system described earlier, the $0.0025 appears to be about an order of magnitude too high.

The second set of sensitivity tests concerns the marginal costs of usage. Since the reported marginal costs of usage are already at or below the lower end of the expected range, Table 11 reports the net efficiency gain per line when all base case marginal costs are decreased 5 percent, increased 10 percent, and increased 20 percent. The last column of

**Table 10.** Mills per Message Versus Installed First Cost per Line

<table>
<thead>
<tr>
<th>Ongoing expense per message</th>
<th>Maximum installed first cost per line</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.00</td>
<td>$25.00</td>
</tr>
<tr>
<td>$0.005</td>
<td>$20.78</td>
</tr>
<tr>
<td>$0.01</td>
<td>Likely</td>
</tr>
<tr>
<td>$0.015</td>
<td>Range</td>
</tr>
<tr>
<td>$0.0195</td>
<td>$6.54</td>
</tr>
<tr>
<td>$0.02</td>
<td>$8.12</td>
</tr>
<tr>
<td>$0.0125</td>
<td>$80.51</td>
</tr>
</tbody>
</table>

**Table 11.** Sensitivity of Results to Changes in Marginal Costs

<table>
<thead>
<tr>
<th>Base case -5%</th>
<th>Net efficiency gain/line*</th>
<th>Maximum initial investment per line</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3.83</td>
<td>$15.31</td>
<td></td>
</tr>
<tr>
<td>$4.14</td>
<td>$16.56</td>
<td></td>
</tr>
<tr>
<td>$4.76</td>
<td>$19.06</td>
<td></td>
</tr>
<tr>
<td>$5.39</td>
<td>$21.56</td>
<td></td>
</tr>
</tbody>
</table>

*Excluding capital costs.

Table 11 reports the maximum first cost per line investment corresponding to each set of marginal costs. As expected, as the marginal cost of usage increases, ceteris paribus, the net gains become larger. Even under the scenario where each base case cost is increased by 20 percent, this still leaves the long-run marginal costs reported by GTS at the lower end of the expected range than has been previously reported in the literature.

The final set of sensitivity tests reported deal with the various elasticities of demand and their effect on the efficiency gain from measured service. In Table 12, all
Table 12. Sensitivity of Results to Changes in Price Elasticities

<table>
<thead>
<tr>
<th></th>
<th>Maximum initial investment per line</th>
<th>Net efficiency gain/line*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case -20%</td>
<td>$ 11.78</td>
<td>$ 2.94</td>
</tr>
<tr>
<td>Base case -10%</td>
<td>14.19</td>
<td>3.55</td>
</tr>
<tr>
<td>Base case -5%</td>
<td>15.38</td>
<td>3.84</td>
</tr>
<tr>
<td>Base case</td>
<td>16.56</td>
<td>4.14</td>
</tr>
<tr>
<td>Base case +5%</td>
<td>17.73</td>
<td>4.43</td>
</tr>
<tr>
<td>Base case +10%</td>
<td>18.89</td>
<td>4.72</td>
</tr>
</tbody>
</table>

*Excluding capital costs.

Elasticities are decreased 20 percent; decreased 10 percent; decreased 5 percent; increased 5 percent; and increased 10 percent. Corresponding values of the net efficiency gain per line and the maximum initial investment per line are provided. In all cases, the sensitivity tests show that the net gain is positive, even after accounting for the initial capital cost.

Summary

When combined with the base case, the sensitivity tests show that over a rather wide range of parameters the implementation of measured rates is socially justifiable and leads to positive improvements in economic efficiency. However, it should be clear from the analyses presented that not just any set of prices will pass this test. In order for the gains to be realized, the usage prices must be set fairly close to the marginal costs of usage. For this to be the case, the incremental metering costs must be relatively low—less than two mills per message in the base case example. This, in turn, requires that the metering system be highly efficient in the way it gathers and processes the call records. If prices are set too high above their respective costs, the same type of losses that measured service is attempting to alleviate will simply appear on the reverse side. That is, usage of the telephone network will be artificially curtailed. Fortunately for the proponents of measured service, the parameters examined in this section indicate that it is possible to design and implement a measured rate tariff which satisfies the strict criterion of economic efficiency.

Summary and Conclusions

The purpose of this paper has been to evaluate objectively the costs and benefits of establishing a measured rate structure in place of the existing flat rate structure for local telephone service. To do this, this paper has examined the costs of implementing and operating a measurement system, the marginal costs of telephone usage, and customers' responses to the imposition of usage prices. Under a relatively wide range of possible scenarios it has been found that measured rates are economically more efficient than flat rates. This finding must be tempered with the recognition that not just any set of measured prices will satisfy the criterion of economic efficiency outlined herein. Measured rate structures must be designed to reflect rather closely the underlying structure of costs if the efficiency gains outlined here are to be realized. As this paper has shown, however, this is an objective which can be achieved.

At the outset of this paper, the decision of the FCC in Docket 78-72 was referenced as having an effect on the question of measured rates. This is because the issue of access charges and measured rates is based on the same underlying economic principle: Costs which vary with usage should be recovered on a usage sensitive basis, and costs which do not vary with usage should be recovered on a nontraffic sensitive basis. Failure to align prices with costs can and does lead to substantial losses in economic efficiency, as this paper has attempted to quantify. The merit of implementing a structure of access charges as proposed by the FCC is beyond the scope of this paper and has been extensively analyzed elsewhere. For present purposes what is important are the metering requirements associated with the implementation of equal access arrangements.

As matters now stand it is important to the financial viability of the telephone company that it be in a position to determine the amount of both originating and terminating usage from interexchange carriers transiting the telephone company's facilities so that it can bill each carrier the correct amount for use of the company's plant. This require-
of measured rates, even though the measurement system would be jointly used for both exchange and interexchange traffic. In this sense, the results presented have been overly conservative. If one were to take into account the requirement of interexchange services in combination with local, the efficiency gains would be somewhat larger.

Despite the current perturbations regarding access charges, some stimulating discussion around the corridors of Congress, assume for the moment that the set of access charges as proposed by the FCC is actually implemented. There has been a great concern expressed that the imposition of the $2.00 per line per month charge on residence customers will cause them to leave the network. If, however, a structure of measured rates is instituted over the same time frame, this concern could be partly alleviated. As shown in the table, the monthly access fee for residence customers was reduced from $10.90 to $4.83 per line, including the incremental cost of the measurement system. This means that the $2.00 per line could be added to the monthly charge during the first year and an additional $2.00 per line the second year, and the resulting price would still be less than the current flat rate paid by residential customers. This is a transitional effect, and the monthly access charge will eventually exceed that currently charged under flat rates. However, the point here is that the monthly access charge will always be less under a regime of measured rates than it otherwise would have been under flat rates. If continuing high rates of penetration of residential subscribers are a fundamental social concern, then measured rates should be preferred to flat rates since they reduce the price of network access to the customer relative to what it would have been under flat rates.

Despite the fact that the foregoing considerations have not been explicitly included in the analysis contained in this paper, the empirical evidence assembled here strongly suggests that a properly designed measured rate structure can lead to substantial improvements in the efficiency of telecommunication services in the United States over the coming years. The measurement costs associated with usage sensitive service are sufficiently low that the benefits derivable from its institution outweigh the costs.

Notes


2. The model as sketched here is quite general. For a more detailed mathematical treatment, see Mitchell, "Optimal Pricing," or J. T. Wenders, "An Introduction to the Pricing of Telephone Service," mimeograph, University of Arizona, September 1976.

3. As will be shown in the next section, all metering costs are not a function of usage. The assumption is made here solely for expositional purposes.


5. The figures contained in this section represent an approximation of an actual GTE telephone company operating environment.

6. It must be pointed out that these are strictly the incremental costs associated with measured rate service and do not include any of the ongoing costs of continued flat rate, business-as-usual, service. Thus, for example, in the case of operator services, one cannot calculate the salaries paid to operators from the information provided in this table without knowing the ongoing costs of operators in a flat rate environment. The ongoing costs of operators are included appropriately in the long-run marginal costs estimates provided here. For another example, in the case of data processing expenses which include measurement and billing there is no allowance for the cost of postage, as this cost is already being incurred in a flat rate environment. As a cautionary note to the reader, the relevant costs to examine are these incremental costs, not the fully allocated costs.


8. Ibid. The judgment is that of Morra and Bowman.


11. Data furnished by Southwestern Bell to author.


14. In the case of the Littlechild-Neuhaus study, the reported cost is for a three-minute call. The PRR cost estimate is for a typical call of unspecified duration, but appears to be approximately four minutes.

15. For the case of SW Bell, where the distribution of calls by time of day and distance was not provided and no weighted average was reported, the following distributions were assumed for purposes of calculation: length of haul, 40% intraoffice; 60% interoffice; time-of-day, 70% day, 20% evening, 5% night.

16. All figures are in year-end 1982 dollars. The cost per call represents long-run marginal costs of four-minute equivalent calls.

17. An alternative revenue objective and perhaps a more realistic one is that telephone companies will design their tariffs to recover only revenues equal to current flat rate revenues at the point of introducing measured rate structures.

18. This figure is not necessarily representative of the outcome which could be expected in other operating company environments. In fact, since this paper was written, a subsequent analysis on a different company within GTE produced a gain in economic efficiency of $4.60 per line per year. The $2.00 figure reported here should be viewed as a minimum gain possible from measured rate service of the rate design utilized in this paper.

19. This potential cost saving, like the net efficiency gains, will vary across companies. Subsequent analysis has indicated potential cost savings from measured rates on the order of $14.00 per year in a different company. The $8.14 reported here should be viewed as a minimum cost reduction possible from measured rate service under a structure of mandatory measured rates. Of course, the usual caveat paribus assumptions must be applied.

20. Testimony of L. L. Selwyn before the New York Public Service Commission, New York Telephone disputes the correctness of this figure.

Local Measured Service

That, when a larger number of phones are available for calling, the value of the service to the customer is enhanced.

The other option was a "measured" (IMR) service but measured in a very limited manner. Thirty calls are offered for a single monthly charge; additional calls or messages entail an additional fixed charge per call. This service option is equivalent to flat rate service for low usage customers, but higher usage customers face a positive price on a per-call basis. As with the flat rate service, different rates are charged for each of the three exchange classes. Although this service does consider call incidence beyond 30 calls, it does not take into account any other characteristics of a particular call. Table 1 shows the pre-SAC rate structure at SNF.

The Decision to Offer Select-a-Call

Two related factors contributed to SNF's adoption of a local measured service option. First, as a result of increasing competitive pressures, fewer products and services are expected to be provided under regulation; therefore, fewer products and services are available to provide revenue support to the subsidized residence access line. Second, a growing need was perceived to separate residence access from usage so that access alone could be identified as the subsidized service element.

Under past market conditions and regulatory practices, pricing policies for local exchange services resulted in a broad definition of the basic (often termed "benefited") service. In addition to access to the local network, the broad definition encompassed the initial service connection, installation of inside wire (on the customers' premises), the telephone set itself, and an unlimited amount of local usage. Although this definition may have been consistent with the goals of the regulators, it is clear that some of the benefits were less than the actual costs of providing them.

Table 1. Rate Structure before SAC

| Exchange class |  |  | 
|---------------|---------------|---------------|---------------|
|               | I ($/month)   | II ($/month)  | III ($/month)|
| Flat residence| 7.46          | 8.59          | 10.05         |
| Measured residence<sup>a</sup> | 4.48          | 5.15          | 6.03          |

<sup>a</sup>Includes 30 local calls; additional local calls are tariffed at 12.5 cents each.

Note: The views and interpretations presented here do not necessarily represent those of the Southern New England Telephone Company. The authors wish to thank Jean Holzer of SNF for the substantial effort she expended in preparing the basic data inputs for this paper.
with some public policy objectives. It was much broader than a
strictly economic definition of benefited service. Most
economists would agree that a more accurate definition recog-
nized that a positive externality exists only for residence
access to the network. Separating the price of access from
other service components, as SAC does, facilitates a clear
view of the subsidized element. Indeed, as competition erodes
more of the revenue base which provides subsidies for basic
telephone service, it becomes increasingly important to define
benefited service as including only network access. The
rate structure SMET proposed to the Connecticut Department
of Public Utility Control (DPUC) separated access from usage
to the greatest extent possible and thus facilitated the
pricing of usage at at least cover incremental cost.

The rate structure actually granted by the DPUC for
SAC can be seen in Table 2. The charge for the initial and
subsequent minutes varies depending on the distance involved.
Essentially, three distance bands are used. A time-of-day
(TOD) discount is applied to off-peak calls. In the past, proposals to the Connecticut DPUC for new
rates have been accompanied by an estimate of the associated
revenue curtailment. Essentially, curtailment effects result from demand responses to higher rates. When these effects
are properly considered, higher rates than otherwise would
be allowed are granted in order to compensate for the revenue
shortfall. The accepted practice has been for SMET to provide
curtailment estimates for all intrastate services when request-
ing rate changes. These estimates are usually developed
through econometric models built with time series data.
However, two aspects of the new rate model were unique.
First, because it was a new service, historical
data, price and quantity data did not exist, making the usual
econometric time series model inapplicable. Second, because
the LMS proposed was to be optional, a specific assessment of
customer preferences had to be made to determine the extent
to which customers would take the service. In order to quan-
tify the curtailment effects from implementing SAC, we had
to know: (1) how many customers would elect the option,
(2) whether they would come from a flat or measured class
of service, and (3) how their usage patterns would change
in the new environment of nonzero usage prices.
Four studies were conducted to develop this information:
(1) a subscriber line usage study (SLUS) to determine indi-
vidual subscriber exchange usage on a detailed basis; (2)
a survey to obtain household demographic data applicable
to customers in the SLUS; (3) a survey of selected SLUS custom-
ners to determine how they would select from among alternative
service options; and (4) research to develop a probability
choice model.1 With respect to the first, individual sub-
scriber local usage data were collected for 7,500 residence
customers. The study tracked their usage as if they had
SAC and gathered data on call incidence, call duration, dis-
tance by band, time of day, and day of week. All subjects
resided in towns served by electronic central offices. These
areas comprise those in which SAC was to be offered and consti-
tute about 75 percent of all residence lines in the state.

To collect the necessary demographic information, ques-
tionnaires were sent to the same 7,500 SLUS subscribers.
Data were gathered on a variety of variables, including age
of household head, sex of household head, household income,
and number of teenagers children. More than 4,500 question-
naires were completed and returned, representing a 60 percent
response rate. From both studies a reliable data base on
usage and demographics became available. From the usage
data and the proposed SAC rates, we determined that about
60 percent of all customers should opt for SAC if they wished
to reduce their phone bills. However, while saving money
is important, we recognized that customers often prefer more
costly alternatives owing to their perceptions of value,
comfort, and risk. People use private cars rather than take
cheaper public transportation and pay extra for designer
clothing. When public phone rates are lower, they may be
more willing to use public transportation and pay for the
higher-quality clothing. Similarly, when the SAC rate is lower,
they may be more willing to subscribe to the service.

Before SMET's proposal was presented to the DPUC, little
work had been done on the problem of choice with respect
to an optional LMS. Two studies had been conducted analyzing
the effects of the GTE mandatory LMS experiment in Illinois
(Jennik 1979; Park et al. 1982). There had also been substan-
tial work at the Bell Laboratories (Pavartin 1979; Wong 1981)
on statistical approaches to assessing the effects of measured
rate structures. These studies addressed the issue of how
ratepayers would alter usage patterns when faced with a nonzero
price, but they did not analyze the choice problem surrounding

<table>
<thead>
<tr>
<th>Residence access $6.25</th>
</tr>
</thead>
<tbody>
<tr>
<td>First minute 3, 4, or 56</td>
</tr>
<tr>
<td>Other minutes 1, 1.5, or 24</td>
</tr>
</tbody>
</table>

1A 60 percent TOD discount is applied to calls made between
8 A.M. and 8 P.M. weekdays and all day Saturday and Sunday.
an optional LMS such as SNET was proposing.

As mentioned earlier, a probability choice model was used to solve the class of service choice problem. Generally, in the models employed, the attributes of each class of service alternative are coupled with the characteristics of individual households to determine the appeal of a particular alternative to a household. Selected SLUS customers were asked in a survey to choose among alternative services, and this information served as input to the discrete choice models.

The primary objective of the survey was to evaluate the effect of a range of alternative rate structures on class of service choice. A range of rates was used for two reasons. First, it enabled us to develop the variability necessary to obtain statistically reliable parameters in the choice models. Second, it prepared SNET for the possibility that the DPU would grant a rate award different in both structure and/or rate level from SNET's proposal. For this study, data were collected over a series of rate elements including access, incidence, duration, distance, time of day, and call allowance. These rate elements and their associated ranges of rate levels were combined to test 72 rate combinations. All subscribers in the survey were given a detailed description of the SAC concept and told what their average monthly SAC bill would be, based on their prior usage. They were also given a hypothetical monthly bill for their current class of service. Finally, they were asked to select between SAC and their present service class. The selection responses were linked to the household demographic information gathered earlier and were used subsequently as input to the discrete choice models.

The modeling process briefly described above allowed SNET to predict: (1) how many subscribers would select the new service, (2) the demographics of those households, and (3) probable SAC usage levels. SNET's derived expectations in this regard are presented in the next section.

SNET's Experience with Select-a-Call

Whether SNET can continue to offer an optional SAC and, at the same time, maintain a stable and predictable revenue flow depends in part upon our ability to predict the level of SAC development, including an understanding of the usage and demographic profile of those selecting the service. In addition, to the extent the company can demonstrate that its expectations have been realized, the Connecticut DPU is reassured that the allowance made for revenue curtailment was soundly based.

This section reports the results of SNET's limited experience with SAC. Initially, we compare actual SAC development to expected levels derived from the model's predictions. Even an analysis of the sustainability issue at this early stage in the development of SAC strongly suggests that any differences should be small. Following the presentation of aggregate buy-up numbers, we view the usage characteristics of those actually taking the service with the characteristics of those expected to take SAC. In addition to viewing our expectations versus realizations, we compare the demographic attributes of those who selected SAC with those of individuals we anticipated would take the service. Finally, the time path of usage for SAC customers is described.

Predicted Buy-Up versus Actual Findings

As discussed above, results from the probability choice model allowed SNET to predict how many customers would switch into SAC from existing services. The first step in this procedure was to determine the probability that any given customer would take the SAC option. These respective probabilities were computed for the group of customers in the survey. Averaging yielded an estimate of the percentage of the eligible population that would buy the new service. In the presentation actually made to the commission, this estimate turned out to be 21.8 percent. The expected number of customers predicted to have taken the service three months after it was made available on July 17, 1983, was 20,589. As of October 29, 1983, the actual number was 20,639. Obviously, the model was remarkably accurate. Approximately 97 percent of these customers came from flat rate service, 3 percent from IMR.

Usage Expectations versus Actual Usage

Usage of SAC entails four elements of subscriber behavior: (1) number of calls per day, (2) average length of call (holding time), (3) number of calls per distance band, and (4) distribution of calls between peak and off-peak periods (time of day). Expectations regarding three of these usage elements are compared with SNET's actual experience. This comparison provides useful insights into both the accuracy of the predictions and the nature of the individuals taking the service. Expectations regarding peak and off-peak calling patterns of would-be subscribers were not developed. Thus, no comparisons on this element are made.

Probabilities developed from the SLUS data base were employed to predict the incidence habits of would-be SAC subscribers. The probability-weighted average calls per day was computed for each distance band. Table 3 displays these estimates and the actual average calls per day for a sample of individuals who took the service during its first three months. As may be seen, actual average calls per day for band 1 were fewer than expected. For band 2, expectations and
actuals are equal, and for band 3 the actual is slightly above expected. As discussed below, more than 80 percent of all calls remain within band 1. It is also interesting to compare both the predicted and observed numbers with those for the entire SLUS data base. These are shown in the third column of Table 3. Clearly, those customers who subscribe to the SAC service are, on average, far below the population as a whole in terms of the number of calls they make per day.

The second element of usage is holding time per call. The predicted values for this element, by band, were computed in the same manner as for incidence, that is, a probability-weighted average for the SLUS sample. These estimates and observed and universe numbers are listed in Table 4. In band 1 the average holding time for those who took the service was slightly below that of the predictions. For the other two bands the actual holding times were greater than expected. Again, the averages for the total population are well above those taking the service.

With respect to distance, Table 5 shows that the distribution of calls was more heavily concentrated in band 2 and less heavily concentrated in band 3 than expected. Also, the distribution for the entire population was more like that predicted than that actually realized. These data indicate that individuals with heavier band 2 calling habits than anticipated took SAC. This result is interesting since, just as low usage customers were expected to take the service, individuals with shorter calling distances were expected to buy the service. This proved to be less true than expected.

The very small percentage of calls made to band 3 should be pointed out. That fact coupled with an extremely small number of observations for calls in that band prevent us from making even tentative statements with regard to band 3 findings. At this juncture, it should also be noted that data are severely limited for peak and off-peak comparisons. Again, our findings center on peak period calling, which accounts for 85 percent of all calls.

### Table 3. Average Local Calls per Time per Day

<table>
<thead>
<tr>
<th></th>
<th>Expected</th>
<th>Actual</th>
<th>Total population</th>
</tr>
</thead>
<tbody>
<tr>
<td>Band 1</td>
<td>1.4</td>
<td>1.0</td>
<td>3.3</td>
</tr>
<tr>
<td>Band 2</td>
<td>0.2</td>
<td>0.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Band 3</td>
<td>0.0</td>
<td>0.006</td>
<td>0.1</td>
</tr>
</tbody>
</table>

### Table 4. Holding Time per Call in Minutes

<table>
<thead>
<tr>
<th></th>
<th>Expected</th>
<th>Actual</th>
<th>Total population</th>
</tr>
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<tbody>
<tr>
<td>Band 1</td>
<td>3.9</td>
<td>3.8</td>
<td>4.4</td>
</tr>
<tr>
<td>Band 2</td>
<td>4.0</td>
<td>4.8</td>
<td>5.3</td>
</tr>
<tr>
<td>Band 3</td>
<td>0.6</td>
<td>5.5</td>
<td>6.3</td>
</tr>
</tbody>
</table>

### Table 5. Distribution of SAC Calls by Distance

<table>
<thead>
<tr>
<th></th>
<th>Expected (%)</th>
<th>Actual (%)</th>
<th>Total population (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Band 1</td>
<td>87</td>
<td>81</td>
<td>85</td>
</tr>
<tr>
<td>Band 2</td>
<td>13</td>
<td>18</td>
<td>12</td>
</tr>
<tr>
<td>Band 3</td>
<td>0</td>
<td>1</td>
<td>3</td>
</tr>
</tbody>
</table>

Demographic Expectations versus Actual Demographics on an Individual Basis

In a manner similar to that for usage expectations, expected demographic profiles were computed for the average individual we predicted would choose the SAC service. The demographic variables investigated were: (1) age of household head, (2) income, (3) ethnicity, (4) marital status, and (5) sex.

Expectations for the demographic characteristics of those actually taking SAC and the demographic profile of the entire SLUS data base are shown in Table 6. The information on individuals who actually took the service is based on rather limited data since demographic information is not currently available for a large proportion of SNET's SAC customers. In fact, only 83 customers comprise the current extent of our data base. These customers represent an intersection of the SLUS demographic survey and the current SAC customer data base.

Several observations stand out as particularly interesting from these limited data. First, a disproportionately large percentage of those buying the service were age 55 and older; in fact, more than 65 percent of those who took SAC fell
### Table 6. Demographic Results

<table>
<thead>
<tr>
<th>Age of household head</th>
<th>Expected ($)</th>
<th>Actual ($)</th>
<th>Total population (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 25</td>
<td>1.6</td>
<td>1.3</td>
<td>3.6</td>
</tr>
<tr>
<td>25-34</td>
<td>21.0</td>
<td>11.5</td>
<td>19.9</td>
</tr>
<tr>
<td>35-44</td>
<td>35.4</td>
<td>5.1</td>
<td>16.1</td>
</tr>
<tr>
<td>45-54</td>
<td>12.1</td>
<td>16.7</td>
<td>16.7</td>
</tr>
<tr>
<td>55-64</td>
<td>20.9</td>
<td>37.2</td>
<td>19.6</td>
</tr>
<tr>
<td>65+</td>
<td>28.1</td>
<td>28.2</td>
<td>24.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Household income</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than $5,500</td>
<td>20.0</td>
<td>22.6</td>
<td>20.6</td>
</tr>
<tr>
<td>$5,500-$15,000</td>
<td>1.6</td>
<td>8.5</td>
<td>10.4</td>
</tr>
<tr>
<td>15,001-$25,000</td>
<td>19.4</td>
<td>16.9</td>
<td>18.7</td>
</tr>
<tr>
<td>20,001-$25,000</td>
<td>16.5</td>
<td>22.6</td>
<td>17.9</td>
</tr>
<tr>
<td>$25,001+</td>
<td>22.1</td>
<td>12.7</td>
<td>12.1</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ethnicity of household head</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>White</td>
<td>85.7</td>
<td>87.8</td>
<td>84.8</td>
</tr>
<tr>
<td>Black</td>
<td>7.9</td>
<td>7.3</td>
<td>10.1</td>
</tr>
<tr>
<td>Hispanic</td>
<td>4.1</td>
<td>2.4</td>
<td>3.5</td>
</tr>
<tr>
<td>Other</td>
<td>2.4</td>
<td>2.4</td>
<td>1.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Marital status of household head</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Single</td>
<td>21.6</td>
<td>16.9</td>
<td>14.3</td>
</tr>
<tr>
<td>Married</td>
<td>52.4</td>
<td>55.4</td>
<td>59.3</td>
</tr>
<tr>
<td>Widowed/Divorced/ Separated</td>
<td>26.0</td>
<td>27.7</td>
<td>26.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Sex of household head</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Male</td>
<td>69.8</td>
<td>70.4</td>
<td>69.3</td>
</tr>
<tr>
<td>Female</td>
<td>30.2</td>
<td>29.6</td>
<td>30.7</td>
</tr>
</tbody>
</table>

Local Measured Service

This section analyzes the usage responses of individuals who selected SAC both in terms of their initial reaction to the service and the development of their usage patterns through time. Although only three months of data are available at this time, some rather interesting patterns can be observed. As with the usage data discussed earlier, several aspects of subscriber usage can be considered here: incidence, holding time, and distance. To illustrate clearly how the SAC usage varied initially and over time with respect to pre-SAC habits, each of the following graphs employs a horizontal line representing the pre-SAC average usage for the same group of individuals.

Figures 1 and 2, showing peak calls per day for bands 1 and 2, reveal two basic observations. First, the initial response of individuals in these bands after taking the service was to curtail rather drastically the number of peak calls they made per day. In these two distance bands, the number of calls in the first month of the service was just above half that of prior usage. Second, for both bands, the adjustment pattern demonstrates a steady return to incidence patterns prior to buying the new service.

The prior usage data on holding time per call, shown...
In Figures 3 and 4, are less complete than those for incidence. For bands 1 and 2 during the peak period, it can be seen in the figures that the initial response was a measurable decrease in holding time per call when faced with a positive price per minute. In each instance, the first two months showed a continued decline in the mean value of this variable, while the third month showed a movement in the direction of prior usage levels in terms of holding time.

**Implications for Sustainability**

As stated at the outset of this paper, the very limited amount of data currently available prevent us at this point from conducting robust statistical analysis or drawing firm conclusions about the long-run sustainability of an optional LMS service. However, some of our present observations provide useful information.

First, the original projections of SRET on how many and who could buy the SAC option seem to be very close to the mark. Thus, the predictability of the service buy-up at the current rate structure appears to be good at least in the short term. Clearly, one of the requirements for sustainability is for the company to be able to predict with a given set of rates for all residence services what the buy-up of the SAC service will be and who will take it. The model has scored well in this regard.

Second, we can develop some hypotheses regarding future experience based on the limited data at hand. Figure 5 points out the nature of these hypotheses for future investigation.

Although we refuse to state firm conclusions on extremely small sample sizes and three months of data; it appears that SAC customers substantially respond to positive prices for usage initially, but adjust their usage patterns toward their previous usage through time. Assuming that this readjustment pattern continues, three possible scenarios come to mind.

First, subscribers may level off their calling habits but at levels below prior usage. The curve labeled I in Figure 5 depicts this situation. Second, they may return to their prior usage patterns, thus remaining with or leaving the service depending on the comparative magnitudes of their bills under the alternatives. The line marked II illustrates this situation. Finally, they might eventually surpass prior usage as a result of facing lower total bills with the new service than with their prior option.

Each of these possibilities merits some scrutiny. First, consider curve III. It would appear that this possibility will not occur. Customer usage under a flat rate service entailed a zero price. Consequently, usage presumably would have already adjusted to its unconstrained maximum. Only a structural shift would cause usage to exceed its prior level.
With regard to curve I, some plausibility exists since a repressive effect of facing positive attribute prices seems likely. Indeed, the probit model employed the assumption that a 10 percent reduction in calling would occur as a result of the usage price effect.

The third possibility, II, also holds some sway in light of the fact that those most likely to take SAC are low usage customers. If, at the same usage pattern, the SAC bill is less than the flat rate bill, then the customer could assume old habits and still enjoy an advantage from SAC.

The predictions from the probit model, at this point, appear to suggest that pattern I is the most likely. The fact that our expectations regarding who would take the service, both in terms of usage and demographic description, appear to be holding true suggests that pattern I, on average, will hold. Nevertheless, more data are required before any conclusions can be drawn.

**Note**

1. This model was described in a paper presented to this conference last year (Nussan et al. 1983).
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Note

1. This model was described in a paper presented to this conference last year (Hauser et al. 1983).
References:


Telephone companies and state regulatory agencies throughout the United States have sought to make access to the telephone network available to as many people as possible by keeping the prices of residential and business basic service access lines as low as possible. By offering some form of especially low-priced residential telephone service in both urban and rural areas, the objective of universal telephone service has been largely achieved. This fundamental telecommunications policy is manifest in the Federal Communications Act of 1934: "to make available, so far as possible, to all people of the United States a rapid, efficient, nation-wide ... communication service with adequate facilities at reasonable charges" (emphasis supplied).

The availability of a low-priced residential service not only benefits the specific customers subscribing to it, but also the remaining customer body by making it possible to communicate among a wider portion of society for goods, services, health, safety, employment, and for general social purposes. The phrase "at reasonable charges" implies a value judgment in pricing policy. It does not mandate or imply that the prices for basic telephone service be set at cost. Indeed, historically the telephone industry has utilized value-of-service pricing techniques and related judgmental considerations in pricing basic telephone service so as to achieve maximum development in residence households and in
business establishments.
The average residential access line fully allocated embedded cost of service throughout the United States ranges between $20.00 to $30.00 per month. In high cost rural areas, the cost increases to the $75.00 to $100.00 range. The cost includes capital recovery at authorized return levels, all operating expenses, and taxes. The average tariff monthly charge for residential access line service(s) ranges between $5.00 and $10.00. The monthly charge for flat rate service in some large, densely populated metropolitan regions ranges upward to $25.00 or $30.00.

Obviously, a telephone service which is priced below the lower end of the range of average prices does not recover its costs and has to be subsidized by revenues from more profitable services. In the predistribution environment, when the structure of telephone service was largely monoplastic, the residual pricing of basic access line services was achieved through subsidies from the interstate separations process and from pricing interstate usage and supplemental services above their respective fully allocated embedded costs. The present sources of cross-subsidy in the New York Telephone Company are shown in Table 1 and aggregate $1.1 billion. The major requirement for supporting revenue from these subsidies is basic access line service. Table 2 identifies the present relationship between the various basic access line services and their respective fully allocated embedded costs. The monthly charges for residence and business basic access lines are, for the most part, less than half the embedded cost.

Basic budget service was first offered in 1969 to buffer the effect of increases in the prices of consumer goods and services, as the company perceived the beginning of spiraling inflation that would cause basic access line rates to increase rapidly. The very low priced basic budget service offered initially at $2.50 per month included the access line, inside wire, and basic telephone set. Later, a number of the large Bell System operating telephone companies began to offer similar low priced lifeline type services. While the monthly charges for these residential service options were set low in recognition of the limited usage over the lines, they were not intended as services exclusively for poorer customers. All telephone companies and regulatory agencies at the time of implementing very low priced options did not wish to differentiate these options especially for needy customers. In some instances, there was the belief that state public service laws would not support preferential rate treatment. In other instances, even though the service features of the low priced option were specifically structured to differentiate it from other established services (zero calling allowances versus a given number of calls associated with traditional message rate service), the management did not wish to commit a service

<table>
<thead>
<tr>
<th>Source of present subsidy</th>
<th>Contribution over fully allocated projected embedded cost (millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>IntraLATA toll</td>
<td>$150</td>
</tr>
<tr>
<td>IntraLATA local call</td>
<td>150</td>
</tr>
<tr>
<td>Supplemented services</td>
<td>100</td>
</tr>
<tr>
<td>Intrastate carrier access charges</td>
<td>100</td>
</tr>
<tr>
<td>Interstate carrier access charges</td>
<td>600</td>
</tr>
<tr>
<td>Total</td>
<td>$1,100</td>
</tr>
</tbody>
</table>

Table 2. Comparison of Present Monthly Charges of Basic Access Line with Fully Allocated Embedded Costs

<table>
<thead>
<tr>
<th>Flat rate</th>
<th>Monthly charge</th>
<th>Embedded cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$7.75-17.12</td>
<td>$26.00-40.46</td>
<td></td>
</tr>
<tr>
<td>Untimed message rate</td>
<td>6.29</td>
<td>24.13</td>
</tr>
<tr>
<td>Timed message rate</td>
<td>5.32</td>
<td>23.62</td>
</tr>
<tr>
<td>Basic budget</td>
<td>2.53</td>
<td>21.34</td>
</tr>
<tr>
<td>Business timed message rate</td>
<td>8.71</td>
<td>21.34</td>
</tr>
</tbody>
</table>

for a specific sector of society through a certification program. Such programs were thought to be costly and burdensome. In the early 1970s, subscription to lifeline services was relatively modest and did not adversely affect the pricing of other services which generated subsidies. However, later
In the decade, following extensive inflation and significant increases in telephone prices, subscription to basic budget service in New York began to rise more rapidly. Figure 1 depicts the growth pattern from implementation in 1960 and projects an estimated 616,000 customers by 1985. Table 3 compares the monthly rate of $2.63 with the monthly cost of $21.34. The total subsidy required from other services to support this unchecked growth is estimated at $136 million in 1985.

Following the divestiture of the Bell Operating Companies from AT&T on January 1, 1984, and given the proposed implementation of federal end-user charges ($2.00 in 1964 growing to a projected $8.00 in 1989), certain sectors of the residence subscriber body, led by customer groups traditionally opting for the maintenance of lower rates, state regulatory agencies, and state and local legislative representatives, protested that local telephone rates would double. These projected increases were described as forcing many low-income customers off the network and acting as a barrier to many new subscribers with low income. Although the Federal Communications Commission provided in its Order that local telephone companies could seek a waiver of the end-user charge from Lifeline service, the U.S. House and Senate began to draft legislation which would, in part, defer or eliminate end-user charges so as to protect the residential body from the rate effects of divestiture.

Figure 1. Subscription to the Low Priced, Unrestricted Basic Budget Service in New York State

<table>
<thead>
<tr>
<th>Year</th>
<th>Customers</th>
<th>Annual revenue at $2.63 per month</th>
<th>Annual embedded cost at $21.34 per month</th>
<th>Total subsidy required</th>
</tr>
</thead>
<tbody>
<tr>
<td>1985</td>
<td>616,000</td>
<td>$19.4 million</td>
<td>$157.7 million</td>
<td>$136.3 million</td>
</tr>
</tbody>
</table>

The core problem in designing basic access charges, particularly for the residential class, is twofold. First, for the purpose of promoting universal service, residential basic access line rates are already highly subsidized. Second, further increase in rates, in addition to meeting normal inflationary cost increases, to offset the transferring of nontraffic sensitive cost allocations from interstate toll back to the subscriber access line is perceived as a threat to universal service. Because the subsidies required to maintain an unrestricted, very low priced Lifeline service such as basic budget are extremely large, and since they give rise to distortions in the rates of competitive usage and supplemental services, the notion of a true Lifeline service targeted specifically to the needy is open for reconsideration.

New York Telephone Company evaluated the present subscription to its basic budget offering by family income to ascertain the extent to which the projected subsidy of $136 million would benefit the truly needy versus families without demonstrated need (incomes above $22,500 annually) who do not qualify for state and federal assistance. Table 4 identifies the extent of subscription to existing services by stratification of family income. Significantly, the majority of present basic budget customers (59 percent) have annual earned family incomes greater than $12,500. This threshold level is identified because, on average, it exceeds that level of income at which individuals and families may qualify for federal and state entitlement aid programs. Consequently, as shown in Table 5, under the present system of pricing, those customers subscribing to basic budget service with annual incomes exceeding $12,500 (59 percent, or 363,000), require an annual subsidy of $82 million. That amount cannot be sustained from the traditional sources of pricing usage and supplemental services, which are more vulnerable to competition in a postdivestiture market. To date, legislative
Table 4. Present Customer Distribution of Basic Telephone Services by Family Income

<table>
<thead>
<tr>
<th>Family Income</th>
<th>Basic budget</th>
<th>Measured rate service</th>
<th>Flat rate service</th>
</tr>
</thead>
<tbody>
<tr>
<td>$7,000</td>
<td>23%</td>
<td>21%</td>
<td>16%</td>
</tr>
<tr>
<td>12,500</td>
<td>18%</td>
<td>17%</td>
<td>15%</td>
</tr>
<tr>
<td>20,000</td>
<td>26%</td>
<td>27%</td>
<td>27%</td>
</tr>
<tr>
<td>40,000</td>
<td>27%</td>
<td>26%</td>
<td>34%</td>
</tr>
<tr>
<td>Over $40,000</td>
<td>6%</td>
<td>9%</td>
<td>10%</td>
</tr>
</tbody>
</table>

Table 5. Unrestricted Basic Budget Customers Benefiting from Subsidy Flow, Distributed by Family Income

<table>
<thead>
<tr>
<th>Family Income</th>
<th>Percentage distribution</th>
<th>Amount of subsidy</th>
</tr>
</thead>
<tbody>
<tr>
<td>$7,000</td>
<td>23%</td>
<td>$32 million</td>
</tr>
<tr>
<td>12,500</td>
<td>18%</td>
<td>24</td>
</tr>
<tr>
<td>Over $12,500</td>
<td>59%</td>
<td>82</td>
</tr>
<tr>
<td>Total subsidy</td>
<td></td>
<td>$138 million</td>
</tr>
</tbody>
</table>

bodies have not adopted formal programs nor have they acted to modify existing programs to provide aid to the needy to continue telephone service. It is doubtful in the near term that legislators will act to create formal subsidies in the tax structure.

New York Telephone Company recognizes its responsibility and long-term commitment to the concept of universal service and has proposed to implement a new lifeline service, designed expressly to aid existing and future subscribers of limited income so they may continue to have access to the telephone network. The monthly charge for the service would be set at a 50 percent discount level of the prevailing access line rate ($2.77 versus $5.47), and outgoing calls would not be timed. The one-time connection charge would be $70.00, payable over six months in equal payments without interest charges. Existing customers could convert to lifeline for a service charge of $30.00.

To ensure that the offering meets the objective of continuing the availability of universal service, it is targeted directly to persons and families of low income who may not otherwise be able to afford telephone service. In this manner, the excess amount of subsidy revenue required ($82 million) for those customers not needing such benefits can be eliminated, and usage prices may be brought to more competitive levels.

To target lifeline to those who truly need it, the company has proposed a simple and cost-effective certification program tied to the five principal entitlement aid programs administered by the New York State Department of Social Services. The company chose this method because it cannot on its own ascertain the critical needs of society in this regard. Government agencies have been created by their respective legislative branches to implement a variety of aid programs, and these agencies are the best qualified to assess whether a person or household requires assistance.

The New York State Department of Social Services' public assistance programs are shown in Table 6. They are administered uniformly throughout the state and are based on financial criteria. Eligibility is determined by income, medical status, and county of residence criteria. The company's proposal requires a simple customer-initiated certification form listing the subscriber's name, telephone number and address, name of entitlement program under which benefits are presently received, and the Department of Social Services identification number assigned to the client. By signing the certification form, the subscriber gives the company the authority to check periodically with the department to ascertain whether welfare benefits from one or more of the stated programs are still being received. The department has agreed to compare its master computer file of welfare clients with a company computer file of lifeline subscribers three or four times a year. If a customer receiving lifeline benefits does not show up on two successive runs, the customer would be notified that lifeline service is being discontinued, and regular usage rate service would be billed retroactive to the first bill date of the first computer run. Of course, the customer could eliminate the back billing by notifying the company immediately that welfare benefits were no longer being received and the lifeline service option should be discontinued. The Department of Social Services agrees that three or four reviews per year are prudent and not administratively burdensome to their operations. The company believes that this periodic verification is reasonable since too frequent reviews would be wasteful, causing needless bureaucratic costs to the company.
Table 6. Entitlement Aid Programs in New York State Administered by the Department of Social Services

<table>
<thead>
<tr>
<th>Program</th>
<th>Representative Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>Families with dependent children</td>
<td>$6,000</td>
</tr>
<tr>
<td>Home relief</td>
<td>6,000</td>
</tr>
<tr>
<td>Medicaid</td>
<td>6,600</td>
</tr>
<tr>
<td>Food stamps</td>
<td>12,900</td>
</tr>
<tr>
<td>Supplemental security income</td>
<td>4,400</td>
</tr>
</tbody>
</table>

and the department. The company has agreed to pay the Department of Social Services for its expenses in handling the three or four annual reviews.

When the company negotiates with a new subscriber for telephone service, all options, including lifeline, will be thoroughly explained. Any new subscriber who indicates eligibility for lifeline by virtue of enrollment in a state entitlement program will be allowed to choose that option. Customers who so choose will have the certification process expedited. They will also be mailed a certification form and will be advised that they are obligated to return the completed form to the company within 30 days. Existing subscribers will also be provided lifeline service on request and will have the certification process expedited.

This proposal, if adopted by the New York State Public Service Commission in July 1984, would be a first in the nation. It could be a model for other utilities and regulatory agencies to follow in achieving lifeline rates targeted to those with demonstrated need and who might otherwise be unable to afford telephone service in light of prospective rate increases. Table 7 identifies the company’s present and proposed pricing options for residence basic telephone service and the movement of existing basic budget customers to the new options.

In making this proposal, the company does not move away from its fundamental position that it is best in the long run to have such subsidies incorporated formally into state legislative welfare programs funded through tax revenues. It recognizes, however, that until state legislators create such programs, the proposal provides the most realistic and administrable solution to the long-standing and sound national

Table 7. Proposed Alignment of Residence Basic Service Options and Redistribution of Existing Basic Budget Customers

<table>
<thead>
<tr>
<th>Present</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic budget ($2.63)</td>
<td>Life Line ($2.71)</td>
</tr>
<tr>
<td>- no allowance, no time</td>
<td>- no allowance, no time</td>
</tr>
<tr>
<td>- unrestricted, all customers may subscribe to service</td>
<td>- targeted by certification to low income</td>
</tr>
<tr>
<td>Timed Message Rate ($5.32)</td>
<td>Timed Message Rate ($5.42)</td>
</tr>
<tr>
<td>- $4 allowance</td>
<td>- no allowance</td>
</tr>
<tr>
<td>- 6-minute messaging</td>
<td>- targeted by certification to low income</td>
</tr>
<tr>
<td>- 3-minute messaging</td>
<td></td>
</tr>
<tr>
<td>Untimed Message Rate ($6.29)</td>
<td>Untimed Message Rate ($6.42)</td>
</tr>
<tr>
<td>- $4 allowance</td>
<td>- no allowance</td>
</tr>
<tr>
<td>- no timing</td>
<td>- targeted by certification to low income</td>
</tr>
<tr>
<td>Flat Rate ($7.75 - $17.12)</td>
<td>Flat Rate ($10.25)</td>
</tr>
<tr>
<td></td>
<td>- $4 allowance</td>
</tr>
<tr>
<td></td>
<td>- no timing</td>
</tr>
<tr>
<td></td>
<td>Flat Rate ($12.08-$26.54)</td>
</tr>
</tbody>
</table>

Note: These are the proposed monthly charges given in New York Telephone's general rate case, Docket 28001, and include the $2.00 Federal End User Charge (EUC) except on lifeline service; petition has been made to the Federal Communications Commission for waiver of charge from lifeline service.

policy of universal service.
I want to address several points that were raised relative to measured service and the appropriateness of this policy. Several points should be emphasized at the outset. The kind of analysis that Edward Beauvais presented is predicated upon the proposition that rates are set at marginal cost. If the rate is set in excess of marginal cost, then the very same kinds of inefficiencies that he asserts exist under a flat rate environment would also exist under a measured rate environment. But if rates are set at marginal cost, then it follows that local measured service charges cannot be counted on to provide a source of subsidy for access. Thus, eventually, the charges for access lines will have to approach their costs, and ultimately we will be faced with, under this proposition, cost-based access and cost-based usage charges. In that context, it is important to put the relative levels of traffic-sensitive cost and nontraffic-sensitive cost into proper perspective. Until 1983, since the FCC announced its decision in Docket 78-72, most of us who do not claim to know much about separations, at least not at the mechanical level, never really thought about the concept of nontraffic-sensitive costs or at least how much of the total plant that constituted. What we have become painfully aware of over the past five or six months is that nontraffic-sensitive costs constitute a very large portion of total telephone plant. If we set access line rates equal to nontraffic-sensitive costs, and set local usage charges equal to traffic-sensitive marginal costs, we end up with a situation in which the basic objective that is suggested for LMS—that of encouraging customers to retain access services where the higher prices of access might otherwise force them off the network—cannot by itself be achieved.

The SNET Experience

The kind of rate plan discussed by James Green and Charles Zarkadas relative to Southern New England Telephone (SNET) does not really address this problem, either. First, if we compare the multielement measured rate plan—the Select-a-Call plan—with the existing 12.5 cents per call measured service tariff which has existed for some time, we find that this is not just a rate structure change, but a rate level change as well.

The average holding time of SNET's Select-a-Call usage is in the range of four to five minutes. Under the Select-a-Call rates, a representative on-peak call in the first distance band of approximately five minutes' duration would carry a rate of about 7 cents—3 cents for the first minute and then a penny for each of the next four. That is about half the preexisting message rate charge for an untimed local message. Thus, it should come as no big surprise that a number of customers who might otherwise have retained the 12.5 cents measured service would go with the 7 cents measured service. Now, in fact, even that somewhat overstates the average rate because, unlike the old 12.5 cents service, the new service has off-peak discounts. So if we had the data to calculate the average rate over all time periods and all distance bands, I think we would find that, in general, it would be considerably below the old rate. Thus, whatever demand effect SNET claims to result from the introduction of the Select-a-Call option must be attributed primarily—indeed, almost exclusively—to the substantial reduction in rate level, and not to the multielement LMS type of pricing scheme.

I do not conclude, and I think it would be completely incorrect to conclude, that the fact that SNET has experienced a penetration level in the range of 20 percent for the new service suggests that customers are enthusiastically accepting the new type of pricing arrangement. All it says is that, if one cuts the price in half, 20 percent of the customers will, over a three-month period, come to the conclusion that they ought to buy the service. This most remarkable of outcomes can hardly be advanced as evidence of some meaningful level of customer interest in local measured service.

The Costs of Measurement and Billing

I would like to turn next to the issue of the costs of measurement and billing and, specifically, to the Beauvais
study. I spoke about this subject at this conference a year ago and reported on my analysis of New York Telephone Company data relating to the costs of measurement and billing of local calls in New York. Based on data produced by NTT, I determined that the costs of measurement and billing for local calls was in the range of 1.25 cents per message. This figure, of course, is not even remotely close to the two mills Beaumont has suggested. NTT itself, while disagreeing with my number, suggested that in that same rate case that its measurement costs were in the range of 0.7 cents, seven mills, again about 5.5 times those suggested by the GTE experience.

Let us take a look at the development of the GTE numbers because I think there may be some problems with them. It is worth noting that none of the GTE costs contain any revenue requirements associated with the initial capital investment. I have made a rough computation of what that would be on a per-message basis assuming a composite 25 percent capital carrying charge which would include rate of return, federal income taxes, and depreciation. I think this is a reasonable estimate to use for this purpose. On that basis, inclusion of the capital costs would add one mill to the two mill cost identified by Beaumont. Bringing the total measurement and billing cost to about three mills per message. The New York Telephone costs, incidentally, included the annual capital-related carrying costs. There are, however, other adjustments which need to be made in the GTE cost study results.

I took a careful look at the figures Beaumont had identified for the cost associated with additional business office activities required to deal with customers on a measured service basis. These are costs in which customers are inquiring about their bills, perhaps disputing their billing, and otherwise increasing the level of costs with the business office. I cannot explicitly challenge the number Beaumont presented, but I have done some computations on those numbers which I would like to share. In the basis of the General Telephone Company of Systems, and other public experience with approximately 433,000 customers and about 2.5 million calls a day, that would translate roughly into an annual total calling volume of approximately 900 million calls. On that basis, the $0.001 to $0.0002 per-call cost for business office services translates roughly into a total annual incremental cost in the range of $40,000 to $225,000, depending upon where in the range one falls. That implies something between 19 and 41 seconds a year of added contact per customer, with the business office, assuming an average total cost of $40 an hour, which I think is a reasonable number. Put another way, the additional business office work required to deal with measured service billing would, according to Beaumont, involve only 1.5 to 4 additional employees for the entire company. I company with 433,000 sub-
contract agreements between AT&T and the RBOCs, the cost an operating company will pay AT&T, which owns all the operators as of January 1984, for operator services will be around 60 cents per call. If we take that as the starting point and assume that such costs are incurred once in 200 cases, then that alone would add 3 mills, and that is the absolute best case, to the costs shown here. If we assume that operator assistance occurs in 7 percent of local measured-rate calls, that would add close to 5 cents to the cost of each call as found by Beauvais. I do not think the 7 percent figure is accurate, but I think the one-half of one percent incidence rate is probably a little low. In any event, it is important to appreciate that this one cost item alone dwarfs all the rest of them, and I really think these figures have to be carefully reexamined before being used as a basis for making judgments as to the relative efficiency of local measured service.

Finally, before leaving the subject of measurement costs, it is worth examining the precise manner in which Beauvais has developed his estimates of the costs of measurement. His methodology begins with basic out-of-pocket costs associated with new equipment which has to be added for the measurement and billing processes, costs associated with additional business office work times, costs associated with additional operator services, additional maintenance, and so forth—and then develops a cost per message on that basis. This method is not comparable to the manner in which GTE has developed its incremental cost of local usage, which embraces all call-related costs and not just those associated with measurement and billing. For these costs, GTE combines the cost of call-set-up costs which are fixed in the short run. Thus, by restricting its measurement cost analysis to out-of-pocket costs, the GTE study ignores long-run variable costs of measurement of the same type that are included in its overall local measure cost calculations. In particular, the measurement/billing costs do not include allocations of central office switching and processor capacity costs, costs which will be impacted in the long run by adoption of LMS. By contrast, the long-run costs developed by GTE include services, separate and apart from any costs associated with measurement, do include recognition of those capacity costs. The figures I have cited for New York Telephone’s measurement/billing costs and similar measurement and billing costs which I have identified for other Bell companies do, in general, include allocations of long-run capacity costs, and they are thus far more comparable to the overall measurement and billing costs developed by Beauvais. The 1.25 cent measurement cost for NY was developed on a basis fully consistent with the incremental cost of local messages in New York, which is approximately 9.8 cents. Again, this is quite a bit higher than the experience that General Telephone Company of Someplace has had, but it involves a far more complex local network with distances in some cases of 40 or 50 miles priced on a local call basis. If we attempt to examine these figures in a consistent way, either one of the two conclusions must be drawn. On the one hand, the reasonably low measurement cost estimates of Beauvais must be increased to correct for his erroneous calculation of operator costs and to include long-run capacity costs attributable to the measurement and billing processes, or, on the other hand, ignore capacity costs on the assumption that the central office has got to be there, and it does not much matter what it is used for. I would submit that the long-run usage costs which have been developed by various companies and have been cited in this paper are far too high. But what we are seeing in this kind of comparison is essentially an effort to show the lowest possible costs associated with the measurement process while at the same time developing the highest possible costs associated with local telephone use. The combination of these two types of calculations is intended to demonstrate a very small cost associated with LMS implementation, while at the same time suggesting that the level of local usage costs is substantial. One RBOC recently attempted to do a study that, at least from a methodological standpoint, did try to achieve a consistent treatment of capacity costs both for the development of measurement costs and for total message costs. What the company in that case did was to assign ESS processor capacity costs on the basis of busy hour utilization both to the call handling cost itself (having nothing to do with measurement costs) and to the cost of measurement. The company then proceeded to undertake a cost/benefit study in which the additional capacity costs and other direct costs of measurement were put on one side of the equation, and the avoided capacity costs due to assured repression or curtailment of usage remaining reflected in the other part of the equation. When the company did that, it discovered the additional costs associated with the measurement of usage were more than double the capacity and other cost savings associated with the repression that had been forecast, which incidentally was at a level very comparable to the GTE experience. Undaunted by this seemingly adverse cost/benefit result, however, the study observed in a footnote that, so to speak, not to worry because the customers who pay usage charges will be charged an amount sufficient to recover these additional measurement costs.

That, unfortunately, is not the point. If we are trying to look at this issue from the standpoint of efficiency, we do not want to look at what the customer pays, we want to look at what the community as a whole pays. I think, for example, that whether or not an operator assistance surcharge applies, operator assistance usage goes up in a measured...
environment. That is a societal cost, irrespective of who pays. It has not been properly recognized here and inciden-
tially was not included in the costs I have cited for New York because that had not been separately isolated. The
government has, however, now incorporated it by including the price of the telephone in the cost of phone use. I also agree with Beauvais that if a measured service pricing environment is to be established, the prices should be based on marginal
cost. I also agree, in principle, with his method of measuring
costs and benefits and of comparing the two. I disagree
with some of the mechanical ways in which this was done:
In particular, I think that if the additional costs of measure-
ment are included on the cost side of this equation, or in
the alternative, if capacity costs are eliminated from the
usage cost side of the equation, then there is no question
but that his analysis would affirmatively demonstrate that
message rate pricing is inefficient and should not be pursued.

**Lifeline Residential Service**

John Hopley presents a compelling argument for adoption of a lifeline type of residential access service specifically
targeted to qualifying low-income customers. Lifeline service
provides an efficient alternative to general adoption of
local measured service and will more effectively accomplish
the universal service goals often ascribed to LMS.

A principal justification for measured service pricing is that it makes telephone service available to people who
could not afford to pay the full price of access. But if measured service pricing is done efficiently, those people
will still have to pay ultimately the full price of access.
The lifeline alternative allows the policy maker to decide
who really needs the subsidy and to make sure that those
individuals, and only those, receive that subsidy. This
is the lowest cost way of accomplishing the social objective
of universal service, which I think we all agree should be
maintained and supported.

At the same time, we need to eliminate inefficiencies
associated with rate plans that simply alter existing sub-
sidies, so that instead of flowing from one class of customers
to another, they flow from high use to low use, or from low
use to high use: this pointlessness is meaningless does not get
us any closer to an efficient pricing plan and more important,
does not satisfy the universal service objective nearly as
well as a targeted lifeline service proposal.

For some reason, we seem to have had no problems with
implementing the concept of targeting in other parts of the
economy. Those six New York state public assistance programs
mentioned by Hopley certainly are targeted; people have to
qualify for them; they cannot just walk in and say "give
me my check." We have programs in many jurisdictions with
respect to preventing utility service disconnection for house-
holds in which every member is over age 65; there are all
sorts of programs like this, but they have not shown up in
the telephone industry. Targeting is not terribly unique
or unusual; it is done all the time, and if it were done
in the telephone industry, we could accomplish the public
policy objective of providing universal service without the
costs, the nuisance, and the public dislike of measured
service, which is simply going to increase everyone’s bill.

When Beauvais’s numbers are corrected, his paper demon-
strates that measured service is inefficient. I think that,
given this knowledge, we have to look for alternatives. The
targeted lifeline subsidy is a good alternative that should
be given serious consideration because it will solve more
of the problems and more of the concerns that have been raised
in the last six months about telephone pricing than anything
else on the table right now.
The papers by Edward Beauvais, James Green and Charles Zarakadas, and John Hopley deal with the future in one respect or another and address the issue and application of local measured service. Beauvais attempts to measure the efficiency gains associated with mandatory local usage sensitive pricing; Green and Zarakadas discuss the potential buy-up and subscriber usage characteristics associated with optional local measured service; and Hopley focuses on local measured service as a means to satisfy lifeline concerns.

As a preface to the Beauvais paper, it is important to recognize that the telecommunications industry is a service industry, delivering a product to consumers who should have a major say in what is delivered, how it is delivered, at what price it is delivered, and under what terms. The fact that local exchange service may be a monopoly service does not detract from the consumer's vote any less than it would in a competitive environment. This perspective is necessary in order to establish proper parameters around Beauvais's predicted results, since at this time consumers are not generally in favor of mandatory local measured service.

The approach employed by Beauvais to determine the efficiency gains associated with local measured service is sound and provides a reasonable method for regulatory agencies and telephone companies to determine the effect of local measured service on consumer welfare. However, the results of the study bring into sharp focus the desirability or need for mandatory local measured service. Beauvais has predicted for General Telephone Company of Somewhere that the institution of mandatory LMS would result, conservatively, in efficiency gains of approximately $2.04 per line per year. This is the equivalent of $17 per month. Although the efficiency gain is positive, it may be considered minimal. Even without being conservative and doubling or tripling the efficiency gain could lead to the same conclusion. That is, the industry believes that the original $2.00 per customer access line charge associated with the FCC's docket 76-72 was not significant in terms of customer effect. If, from an industry perspective, $2.00 per month is not significant, then it is difficult to conclude that the efficiency gain measured by Beauvais would withstand regulatory scrutiny or receive acceptance by customers, should they be asked to trade their flat rate service for LMS.

From a technical perspective, Beauvais may have defined the efficiency gain too narrowly and overlooked certain countervailing effects. For example, in attempting to achieve a zero revenue effect from the introduction of mandatory LMS, Beauvais reduced the price of the residence and business basic access line charge. The price reduction, coupled with mandatory usage measurements, could prompt different reactions on the part of residence and business customers that may reduce the efficiency gains noted in the Beauvais study. Specifically, the 40 percent reduction in the residence customer exchange line charge could cause some residential customers to buy up to a second line. This cross-elastic effect was not considered by Beauvais and may, in fact, reduce his efficiency gains since the price of the second access line would be far below its incremental cost. Large business customers may be less inclined to curtail their usage and more inclined to concentrate their usage over fewer exchange access lines. Should that be the case, the potential for stranded local loop investment exists and, again, would reduce the efficiency gains noted in the Beauvais study.

Mandatory LMS is thought to be desirable not only for reasons of economic efficiency but also for reasons of equity. But, in a world of imperfect competition and in a world where consumers do not always make rational decisions based upon price, some must challenge the necessity of mandatory LMS if residential consumers preferring flat rate service are willing, as a class, to cover the economic cost of providing that service. The existence of usage sensitivity and flat rate pricing is not unique to the communications industry; both are used by automobile leasing agencies which have options of daily rates or pay-by-the-mile; restaurants offer buffets (all you can eat for a fixed fare) versus a la carte; the banking industry offers flat rate checking versus a charge per check. In fact, what may be regarded as a pseudo-flat rate approach has been developed in the gas and electric
industry to the extent that consumers can now levelize their payments over twelve months so that monthly usage variability is eliminated. Although fluctuation over the twelve-month period will still be reflected in the customer's annual charges, there exists a clear preference for predictability of payment. In short, the communications industry should recognize that consumers, in many respects, prefer a flat rate approach, and if they are willing to pay for it, they should have it.

The question of choice is the subject of the study performed by Southern New England Telephone. SNET has recognized in its analysis that while saving money is important to consumers, they often prefer alternatives which are more costly because of the consumer's "perception of value, comfort, and peace." This intrinsic consumer preference is enfolded in the predictive equations of SNET.

The positive aspect of the study performed by SNET is its approach to consumers to demonstrate the potential monetary benefit of switching from flat rate service to LMS. Before the introduction of optional LMS the company provided information to the consumer regarding his/her usage characteristics. These data were priced out as if the customer had LMS and then compared with the flat rate charge. This valuable exercise is a key component to educating consumers and providing them with the appropriate information to make the right decision as to which service is best for them. Without such an analysis, many of the barriers, fears, and concerns of consumers regarding LMS will continue.

On the negative side, however, is the approach adopted by SNET to establish prices for LMS in relation to the prices for flat rate service. It is here that a forced fit relationship is created which not so much affects the ability of SNET to forecast buy-up as creates the buy-up. To the extent that the relative costs of each of the services, flat rate and local measured, were not reflected and even to the extent that the relative proportionate costs of the services were not maintained in perspective, the marketplace receives improper price signals. Conceptually, the sustainability of LMS as an option to flat rate is more properly framed if each customer pays the same basic exchange access fee without any usage charges; the flat rate subscribers would then pay an additional lump sum to reflect in the aggregate the average usage costs for those consumers as a class, and metered customers would pay only for the usage they consume. The consumer would then have the proper perspective about which service is truly best for him or her, and a truer measure of the sustainability of LMS as an option to flat rate would be objectively provided.

Hopley's discussion regarding targeted Lifeline service represents a genuine attempt to address a very controversial area which requires resolution if prices for exchange telephone service are driven to cost because of the need to reduce access fees and message toll prices. However, in the development of a targeted Lifeline service, monthly prices are not the only element that need to be considered. Most of the other related tariff charges or tariff regulations were omitted from Hopley's discussion and do require resolution in order for a complete package to be presented to regulatory and other government agencies. For example, Hopley does not address the question of whether service connection charges should be adjusted for those who qualify for Lifeline service, nor does he address deposit practices with respect to those particular customers. If it is a true financial hardship for low income consumers to pay higher monthly exchange rates, substantial front-end burdens such as the combination of service connection charges and deposits may preclude many of these potential customers from ever becoming subscribers simply because they cannot afford to become customers. The third element that requires resolution with respect to a targeted Lifeline service are the practices that would be followed with respect to termination due to nonpayment. The final element missing from Hopley's analysis is the funding and sustainability of the funding for a targeted Lifeline service. Although this element need not be critically analyzed at this point, future planning must reflect this key consideration.
customers are subsidized, low income users will begin to face a price which is either unacceptable or unmeasurable. This is the message of Edward Bauwals, James Green and Charles Zarkadas, and John Hooley. As long as competition is the policy choice in the telecommunications industry, it is an accurate one. It is the options to avoid the threat to universal service offered by these authors which raise questions.

By far the best option proposed in the three papers is the mandatory local measured service rate design by Bauwals. His paper is a needed quantitative analysis of the net efficiency benefits of LMS which not only unbundles access and usage but prices usage on the basis of its cost-causative components. While the paper suggests that the net efficiency gains of an LMS system, if properly costed and after accounting for the added costs for measurement and billing, may only be slightly positive today (about $2.04 per line per year in the base case), it does suggest that LMS would produce larger savings in the faster growth environment which can be expected as new interactive services are offered as part of local service. But it is the unbundling of access and usage which Bauwals sees as the main contribution of LMS to maintaining universal service. Because long-run marginal costs for local service are increasing and usage is more elastic than access, Bauwals's LMS design by pricing usage at or near its marginal costs means that the charge for access to the network must be reduced to stay within the embedded revenue requirement for the utility. In essence, LMS by unbundling access and usage has developed a "new" source of contribution for access.

Green and Zarkadas acknowledge that LMS not only lowers the price of access to the network but also provides the customer with control over his or her bill. Instead of paying for "average" usage in the flat rate, LMS allows a customer to buy only as much as he or she wants. But, Green and Zarkadas propose an optional LMS system which, while responsive to universal service concerns, is inferior to a mandatory system when other considerations about the future telecommunications market are considered. Optional LMS, as Green and Zarkadas show, becomes a choice of low users while high users stay on the flat rate; as a result, the efficiency gains of the mandatory system are not likely to be achieved. In addition, a mandatory LMS system in an environment of increasing usage will automatically translate costs into revenue, providing earnings stability for the company and a means to recover the cost of new services from the user. Indeed, it is difficult to imagine the development of new local services absent LMS. Optional LMS, unless it becomes mandatory, does not provide these benefits.

An option not discussed in any of these papers is one which exists in many jurisdictions today: Message unit...
packages in various forms such as zero, 20, or 60 call allowances with additional message units being priced at some additional costs per call. This option is no more than forced averaging in smaller ranges than the flat rate, but it is a viable option in a slow growth, primarily voice communication system to ensure universal service. However, like the optional LMS system, it provides no benefits of efficiency gains, earnings stability, or the practical ability to offer new services and charge the users of those services. In addition, this option as well as optional LMS will inhibit the ability to develop a truly effective lifeline rate, particularly under conditions of high growth and increases in cost.

While Beauvais and Green and Zarkadas use LMS as a rate design to produce reduced access prices for everyone as well as to allow customers to control their bill, Hopley takes another tack, the targeted lifeline approach. His argument is why subsidize everyone when only some people need the subsidy? Why not reduce the amount of subsidy to only that needed to maintain universal service by helping only those who are in danger of leaving the system because they cannot afford the increases? He recognizes that an essential question to answer is whether the administrative costs of a certification program and the reliability of the funds for the subsidy outweigh the costs of using an untargeted lifeline approach where some of the benefits would go to those in need of no subsidy. By intelligently using existing welfare programs as a means of certification and wisely not trying to make continual adjustments every time a participant's circumstances change, Hopley proposed a targeted lifeline system which would meet the potential threat to universal service while at the same time minimizing the effect of the "subsidy" on other ratepayers.

Although each of the authors' options is responsive to universal service concerns, they are so in a way that changes the "traditional" definition of universal service. As Green and Zarkadas admit, universal service which at one time meant access and unlimited usage has been redefined by them to include merely access. Beauvais and Hopley also focus on access as the means to ensure universal service. What is lacking from their development of options is a borrowing from the experience gained from the rate design arguments and proposals in the electric industry about marginal cost pricing, inverse elasticity, time-of-use rates, and inverted lifeline rates. These discussions suggest the options presented in all three papers are too narrowly drawn. For example, as new local telecommunications services are developed and local service offers both voice communication and interactive services, why not use an untargeted, lifeline rate in which access and some part of usage are "subsidized" by some block of usage or component of usage priced at full marginal costs? Reducing the cost of the duration element for some initial period might be justified on the ground that the primary growth area in local service is interactive services and that, in general, interactive services have longer holding times than voice communications. The effect would be to return universal service closer to its traditional definition in which both access and some socially designated desirable level of usage are truly affordable to all. Such a system may well make a targeted lifeline system and Hopley's either too expensive or too narrow as a public policy objective. The development of a mandatory LMS system with the aim of retaining universal service as we know it today is no more illogical or unattainable than the inverted lifeline systems which have been adopted for various electric utilities to achieve similar goals. The key will be to develop adequate cost information and methodologies to develop an appropriate LMS system.
Part Five:
Universal Service and the
Access Charge Debate
DO RECENT FCC TELEPHONE RATE REFORMS
THREATEN UNIVERSAL SERVICE?

Kenneth Gordon and
John Herling

This paper addresses the question of whether recent pricing reforms undertaken by the Federal Communications Commission (FCC) constitute a threat to "universal" telephone service. The paper is organized as follows. The first section provides legal and historical background on the universal service policy goal. It examines conceptual issues surrounding the definition of universal service and possible economic rationales for government intervention to bring it about. The second section analyzes demand for telephone access and surveys recent econometric evidence on the sensitivity of demand to changes in prices and other demand-influencing factors. The third section describes the price changes attributable to recent regulatory decisions, in particular those related to the FCC's plan to implement a system of flat access charges to cover nontraffic sensitive costs of providing telephone service. Net price effects of these policy changes are not large. Given that reforms are to be phased in over several years (during which time other factors will be operating to increase demand) and that demand for access is estimated to be relatively insensitive to price changes, our

Note: The views expressed are those of the authors and should not be construed to reflect those of the Federal Communications Commission or any other member of its staff.
The conclusion is that any effects on telephone subscribership are likely to be quite small. The fourth section considers policy issues and examines alternative means for mitigating any adverse effects that might occur as a result of attempting a system of access charges. The last section contains a brief summary of principal conclusions.

**Universal Service**

**Legal and Historical Background**

The term "universal service" appears in no public law, and there is no authoritative source defining precisely what it means. Let alone how it might best be achieved. Within the telephone industry it is a shorthand expression generally used to refer to Title I of the Communications Act of 1934. That title charges regulation "to make available, so far as possible, to all the people of the United States a rapid, efficient,Nation-wide, and world-wide wire and radio communication service with adequate facilities at reasonable costs." In simple terms universal service might take to mean that every household has, or readily could have, convenient to its premises, the ability to make or receive telephone calls. That is what the term meant to Theodore Vail, the man who coined it in 1910. He believed that "[p]roperly set up, a connection with the telephone system should be within reach of all." In modern discussions the issue is usually framed in terms of whether an individual has "access" to the telephone network. Bridger Mitchell (1962) notes that a binary view of access—an "either you have it or you don’t" conception—presumes a definition of "service," in the above definition, the words "has," "readily could have," and "convenient to its premises" obviously admit some degree of "flexibility" into the definition of access and hence universal service. Vail’s "take-up" of a connection—"within reach"—can refer to a lot of things. So nearby pay phones count? Should a distinction be drawn between persons who voluntarily "drop" to drop or forgo service because of higher prices? More fundamentally, can such a distinction actually be validly drawn? If a consumer refuses to subscribe when offered the option of paying a nominal access charge and higher per-call charges, has that consumer effectively "dropped" the network or denied access?

In this paper access is defined in terms of a household's first on-premise connection to the network. By that definition, a pay phone in a hallway of a housing house or college dormitory does not provide access to the telephone network, although there is clearly a sense in which that is precisely what it does. A lifetime service providing dial-tone and a limited number of local calls for a fixed charge does provide access. Thus defined, the level of access to the telephone network in the United States is very high indeed. As illustrated in Table 1, it averages well above 90 percent for the nation as a whole and for certain states approaches 100 percent. The goal of universal telephone service has been substantially achieved in the United States. Table 2 shows how telephone penetration rates in the United States have grown over time. The growth and current high level of telephone subscribership can be accounted for economically in terms of increases in both supply and demand. On the supply side, continuous improvements in technology have gradually reduced the real costs of telephone service, extension of service to rural areas has been promoted by governmental loan subsidies, and local residential service (including access) has been funded in part by overcharges on long distance calling. On the demand side, changes in virtually all demand-influencing factors have been in a direction increasing demand. (The Telephone demand relation is discussed later.)

**Economic Rationales for Promoting Universal Service**

Two economic rationales might justify government intervention to promote a level of telephone subscribership greater than that which would occur if consumers were to pay cost-based prices. These are the existence of important external effects and the political classification of telephone access as a "merit good."

The externality argument is usually applied to telecommunications posits the existence of important consumption externalities. A positive consumption externality occurs when consumption of a product by one person directly increases the economic welfare of others. The value to any individual of being on the telephone network depends on the availability of others to call (or be called by). In deciding whether to subscribe to telephone service, an individual may not take the value to others of his or her own presence on the network fully into account. Hence, in certain circumstances it could conceivably be socially efficient to subsidize access to the telephone network. In particular, a subsidy can be justified on externality grounds assuming two conditions are satisfied: (1) There are individuals for whom costs of service exceed personal benefits and who, therefore, would not subscribe without a subsidy, but whose presence on the network is socially efficient when the external benefits are reckoned; and (2) the external benefits exceed the costs of subsidization.

While the consumption externality hypothesis is frequently cited in support of subsidies to particular groups, there is little empirical evidence to support it. Summarizing the vast literature in his 1979 treatise on telecommunications...
### Table 1. Telephone Penetration in the United States, by State, December 31, 1981

<table>
<thead>
<tr>
<th>State</th>
<th>Percentage of households with telephone service (%)</th>
<th>State</th>
<th>Percentage of households with telephone service (%)</th>
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### Table 2. Development of Residential Telephone Service in the United States, 1961 - 1981

<table>
<thead>
<tr>
<th>Year</th>
<th>Percentage of households with telephone service (%)</th>
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<td>72</td>
<td>92</td>
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<td>71</td>
<td>93</td>
</tr>
</tbody>
</table>


a1972 and earlier years exclude Alaska and Hawaii.

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The figures economics, S. C. Littlechild (p. 82) concludes that the evidence "is not sufficiently reliable to prove the externality hypothesis, but neither does it offer support for it. An explicit attempt to test the hypothesis would seem to be indicated."

Recently, Lewis Perl (1984) has carried out such a test. His work suggests that the evidence may be a very modest consumption externality associated with telephone access at the local level: that is, telephone subscribers in a particular locality may benefit in a small way and up to a certain point from increases in local network subscribers. If government internalization of these externality were necessary (private internalization efforts proving inadequate) and could be cost-justified (problematic according to Perl), that would at most provide an economic rationale for intervention to internalize externalities at the local level. Note that attempts to internalize consumption externalities at the local level would simultaneously operate to internalize any similar externalities that might exist over broader geographical areas. The reason is that a subscription to telephone service provides "access" to the unified local and
argue for government intervention to internalize consumption externalities associated with telephone access. Whether such intervention actually represents sound public policy would still depend on how much it costs, the magnitude of the external effects, and the extent of private intervention efforts. At current high levels of penetration and faced with the prospect of relatively modest short-term cost increases, the externality argument supplies at best a weak basis for opposing rate reform. Recognition that the current system of cross-subsidies will become increasingly unsustainable in a competitive environment further weakens the case for opposition to change. Finally, if uninternalized consumption externalities are a serious regulatory concern, a policy of restricting measured service offerings appears an inappropriate way to respond. Disallowing low cost service options does not help poor people, it excludes them. Forced bundling of dial tone with unlimited local calling raises the cost of telephone service for many consumers.

The 'merit good' rationale for subsidizing telephone service is simply a different form of the consumption externality hypothesis and, as such, is subject to all of the aforementioned criticisms, most important the externality argument's vacuity as a genuine guide to policy making. In this case the posted source of external benefits is not the ability to call subscribers who without a subsidy would not be available for calling; it is, rather, the utility allegedly derived simply from knowing that subsidized subscribers are hooked up to the telephone system.

The case for assigning merit good status to telephone service is weak. For a merit good like school lunches, an in-kind transfer (lunch versus lunch money) can be justified on the grounds that external benefits to the population at large derive from improved nutrition among young people rather than greater monetary income which might be spent on junk food. For the adult poor, it is by no means clear that external benefits associated with income redistribution are, in general, attached closely to consumption of particular goods. There may well be a case for helping the poor, but there is little basis for arguing that help should necessarily take the form of below cost telephone access.

Obviously, even if a political judgment is made that help for the poor should take the form of subsidized telephone access, that could still not justify a blanket subsidy. It may be that one of the "goods and services" we wish to have exogenously consume is consumption of telephone service by poor people, but presumably we also collectively prefer this to be done in a manner that minimizes the effective cost to society. If we really want to help the poor, we should do so efficiently, so we can help them even more. It is well worth noting that there is currently no evidence that either past or proposed assistance programs for telephone service

are either targeted toward deserving groups or formulated in such a way as to minimize the costs of substituting telephone service for the poor.

Determians of Demand for Telephone Access

Theoretical Framework

To gauge the effects of changes in regulatory policy or consumer demand for access to the telephone network requires an economic model or theory describing important factors affecting consumers' decisions to subscribe for service. As with any scientific model, a good economic model does not attempt to duplicate reality, an impossible task in any event. The goal is to abstract from reality in such a way that much may be explained by comparatively little. This process of abstraction necessarily involves exclusion of what may be critical influences for particular individuals. The focus is instead on general influences that affect most consumers; predictions are, for this reason, forecasts about average effects.

Economic analyses of telephone demand treat telephone service like any other scarce good. Demand is hypothesized to depend upon the price of service, the prices of complementary goods, the prices of substitute goods, personal income, individual tastes and preferences, and so on. Changes over time in virtually all these factors have tended to increase the fraction of consumers who subscribe to telephone service. In real terms, the prices of telephone service and its complements have been falling; the prices for substitutes for telephone service have been rising. Real incomes and the opportunity cost of time have been rising, and demographic changes (such as overall aging of the population and an increase in the number of single-earner households) have been working to increase demand for access to the telephone network. This is an important point in this, the FCC's plan would phase in access charges over several years. To the extent that other factors affect demand and their effects are in the opposite direction from access charges, they act to mitigate the effect of access charges. Rising prices for energy and other substitute goods (postage, time), falling prices for telephone instruments, long distance service and other complementary goods (home computers, stereo systems, shopping services), rising real incomes, an aging population, and other factors all operate to offset the effect of access charges gradually being phased in. Failure to take these other demand-influencing factors into account will result in an understatement of the subscriber penetration levels actually likely to prevail in the future.

Empirical Estimates of Demand Elasticity Parameters

Numerous studies have attempted to estimate the parameters of the telephone demand relation empirically. These vary greatly in quality, type, sources of data, theoretical model specification, and statistical estimation technique. Significantly, despite these differences, the studies uniformly indicate that demand for access to the telephone network is highly insensitive to price changes. (See Tables 3 and 4.) Moreover, there is evidence that demand has been becoming progressively more inelastic over time. While existing estimates indicate a highly price-inelastic demand for telephone service, there are good reasons grounded in statistical theory which suggest that these estimates still probably overstate the actual degree of price sensitivity. This stems from the basis for concluding that effects of recent federal decisions on levels of telephone subscribership are likely to be small. It, under assumptions which overstate the likely effect of those decisions, the effect is nevertheless small, there is a strong analytical basis for drawing that conclusion.

One source of upward bias arises because demand for telephone service has been growing over time while the price of service has been falling. In price-theoretic terms, the demand curve has been shifting outward to the right at the same time there have been movements downward along that demand curve. This implies that estimates based on data from more distant historical periods will overstate the actual current elasticity. (Some of the estimates are based on data that are outside the range of more recent experience. They were made (or, more precisely, the underlying data were generated) during periods when prices were higher, demand was lower, and penetration rates were lower. A price increase will have a different effect depending upon the initial level of demand and the initial prevailing price. The effect of a price change today will be smaller than it would have been fifteen years ago because the real price is lower today, and the level of demand is higher.)

A more general source of upward bias in existing estimates results from theoretical model misspecification. Some of the estimates are based on models which relate subscribership to total charges rather than to charges for simple access. Demand for access (the option of making or receiving calls) is presumably less elastic than demand for local or long distance calling. Faced with higher prices, most consumers will economize on usage rather than forgo service altogether. Estimates of elasticity based on charges for total service will therefore overstate the elasticity of demand for access.
Table 3. Access Demand Elasticities Cited in Analysis of the Effects of Federal Decisions on Local Telephone Service

<table>
<thead>
<tr>
<th>Study</th>
<th>State (company)</th>
<th>Customers</th>
<th>Short run</th>
<th>One year</th>
<th>Long run</th>
</tr>
</thead>
<tbody>
<tr>
<td>Egan</td>
<td>AR, KS, MO, OK, TX (Bell)</td>
<td>Business</td>
<td>-.01</td>
<td>-.03</td>
<td>-.07</td>
</tr>
<tr>
<td>Egan</td>
<td>AR, KS, MO, OK, TX (Bell)</td>
<td>Residence</td>
<td>-.01</td>
<td>-.03</td>
<td>-.07</td>
</tr>
<tr>
<td>Doherty</td>
<td>NY (Bell)</td>
<td>Business</td>
<td>-.04</td>
<td>-.09</td>
<td>-.11</td>
</tr>
<tr>
<td>Carr</td>
<td>NY (Rochester)</td>
<td>Residence</td>
<td>-.04</td>
<td>-.13</td>
<td>-.16</td>
</tr>
<tr>
<td>DRI</td>
<td>CT (Bell)</td>
<td>Residence</td>
<td>-.03</td>
<td>-.08</td>
<td>-.08</td>
</tr>
<tr>
<td>Gentry</td>
<td>TN (United)</td>
<td>All</td>
<td>-.24</td>
<td>-.24</td>
<td>-.24</td>
</tr>
<tr>
<td>Gentry</td>
<td>VA (United)</td>
<td>All</td>
<td>-.22</td>
<td>-.22</td>
<td>-.22</td>
</tr>
<tr>
<td>Perl</td>
<td>National Survey (1970 data)</td>
<td>Residence</td>
<td>NA</td>
<td>NA</td>
<td>-.09</td>
</tr>
<tr>
<td>Perl⁸</td>
<td>National Survey (1980 data)</td>
<td>Residence</td>
<td>NA</td>
<td>NA</td>
<td>-.03</td>
</tr>
<tr>
<td>Reinking</td>
<td>UT (Bell)</td>
<td>All</td>
<td>-.04</td>
<td>-.04</td>
<td>-.04</td>
</tr>
<tr>
<td>Miller</td>
<td>MI (Bell)</td>
<td>All</td>
<td>-.08</td>
<td>-.08</td>
<td>-.08</td>
</tr>
<tr>
<td>Allemann⁹</td>
<td>National, Cities</td>
<td>Residence, FR</td>
<td>NA</td>
<td>NA</td>
<td>-.17</td>
</tr>
<tr>
<td>Allemann⁹</td>
<td>National, Cities</td>
<td>Residence, FR</td>
<td>NA</td>
<td>NA</td>
<td>-.02</td>
</tr>
</tbody>
</table>

Table 3. Access Demand Elasticities Cited in Analysis of the Effects of Federal Decisions on Local Telephone Service — continued.

<table>
<thead>
<tr>
<th>Study</th>
<th>State (company)</th>
<th>Customers</th>
<th>Short run</th>
<th>One year</th>
<th>Long run</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fleenan</td>
<td>National, States</td>
<td>Residence</td>
<td>NA</td>
<td>NA</td>
<td>-.05</td>
</tr>
<tr>
<td>Davis et al.</td>
<td>Bell System</td>
<td>All</td>
<td>NA</td>
<td>-.02</td>
<td>-.08</td>
</tr>
<tr>
<td>Mahan</td>
<td>NC (United)</td>
<td>Residence</td>
<td>NA</td>
<td>NA</td>
<td>0</td>
</tr>
<tr>
<td>Heidt</td>
<td>NE Tel. (Bell)</td>
<td>Residence</td>
<td>-.04</td>
<td>NA</td>
<td>-.20</td>
</tr>
</tbody>
</table>


⁹The estimating equations used by the authors of these studies make some provision for the availability of substitutes for flat rate service such as local metered service, where available. Theoretically, this should improve their usefulness as measures of the elasticity of demand for access.
Table 4. Estimates of Price and Income Elasticities of Demand for Access in Telecommunications Demand: A Survey and Critique

<table>
<thead>
<tr>
<th>Class of customer and study</th>
<th>Dependent variable</th>
<th>Price elasticity</th>
<th>Type of data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allenman</td>
<td>NE</td>
<td>-0.26</td>
<td>CS: Cities, U.S.</td>
</tr>
<tr>
<td>Feldman</td>
<td>NE</td>
<td>-0.05</td>
<td>CS: States, U.S.</td>
</tr>
<tr>
<td>Per-l</td>
<td>telephone availability</td>
<td>-0.08</td>
<td>CS: Households, U.S.</td>
</tr>
<tr>
<td>Rash</td>
<td>NE</td>
<td>-0.11</td>
<td>TS: A, Ontario and Quebec</td>
</tr>
<tr>
<td>Wavermon</td>
<td>NE</td>
<td>-0.12</td>
<td>TS: A, Ontario and Quebec</td>
</tr>
<tr>
<td>Business Wavermon</td>
<td>NE</td>
<td>-0.09</td>
<td>TS: A, Ontario and Quebec</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Class of customer and study</th>
<th>Dependent variable</th>
<th>Price elasticity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential and business combined Davis et al.</td>
<td>Total telephones</td>
<td>NE</td>
</tr>
<tr>
<td></td>
<td>Test residence main stations</td>
<td>NE</td>
</tr>
</tbody>
</table>

Symbols: NE: not estimated; CS: cross-section; TS: time series; A: annual
Table 4. Estimates of Price and Income Elasticities of Demand for Access in Telecommunications Demand: A Survey and Critique (cont'd.)

<table>
<thead>
<tr>
<th>Source:</th>
<th>Page(s)</th>
<th>Notes on Tables</th>
<th>Notes on Tables</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lewis &amp; B. Taylor</td>
<td>Table 3-2</td>
<td>Includes non-U.S. data</td>
<td>Includes non-U.S. data</td>
</tr>
</tbody>
</table>

The table provides estimates of price and income elasticities of demand for access in telecommunications. The estimates are based on various models and data sources, and include both price and income elasticities. The table also notes that the estimates are subject to a number of caveats and limitations.

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A related fact is that when alternatives (substitutes) for flat rate service are included in the specification of demand, the measured elasticity of demand for access falls. This suggests that some people will respond to higher prices by selecting lower cost alternatives (measured service, line options, and so forth) rather than dropping off the network. Omitting the prices of relatively close (and less expensive) substitutes thus leads to an overstatement of the elasticity of demand for simple access.

A similar source of upward bias induced by misspecification results from failure to account explicitly for the effects of changes in prices of complementary goods and services. In particular, telephone equipment and long distance service. Lewis' studies are illustrative in this regard. She finds that demand for access has become more price-inelastic over time. The reason is that other demand-influencing factors (largely omitted from Perl's models) operated in the same direction as price changes during the interim between study sample periods (the early and late 1970s). Changes in most demand-determining factors increased demand, and these combined with lower prices imply that a reduction in measured elasticity should be observed. If there had been no major changes in the underlying structure of demand between the two sample periods, the initially estimated price elasticity coefficient would provide a biased measure of the actual effect of price changes (because it reflects the effects of omitted variables as well), but would nevertheless generate accurate predictions because of the (assumed) stability of the underlying demand structure.

In Perl's new study, long distance rates are not included as a factor affecting the demand for access, although there is clearly a strong complementary relationship between the two. This means that the price coefficient picks up some of the influence of changes in long distance rates, among other things. That will not affect the predictive capability of the model as long as the underlying demand structure remains the same. Implementation of access charges will, however, result in lower long distance rates—an important change in the underlying structure of demand which operates in the opposite direction from the effect of higher access charges. Lower telephone equipment prices have the same effect. In Perl's new study, the price coefficient is therefore overestimated the effect of access charges, and that coefficient is, of course, already close to zero. Indeed, it may well be zero, since recognition of upward bias leads one to question results of tests for statistical significance. If a confidence interval were constructed for an unbiased point-estimate at a conventional level of confidence (say, 95 percent), it might well include zero. In that case the null hypothesis that small price changes have virtually no effect on demand could not be rejected. That would not contradict the law of demand.
Kenneth Gordon and John Harring

It would simply imply that there are very few people at the margin at current prices. In this regard it is interesting to note that the "consensus" demand elasticity estimate given by Lester Taylor (1980, p. 139) in his survey of the telephone demand literature is constructed with zero as the lower-bound-

Effects of Regulatory Decisions on Costs

Policy Changes

The most important policy change to be considered is that mandated in the FCC's so-called access charge order in Docket 78-22. The commission calls for a restructuring of the way in which nontraffic sensitive (NTS) costs of providing telephone service are recovered. Historically, about 25 percent of these costs have been recovered through usage sensitive charges paid by long distance users. This meant that a person who made no long distance calls could avoid paying the full costs of his or her access line. In particular, the individual could avoid a portion or none of the NTS costs allocated (arbitrarily in economic terms) to the federal jurisdiction and recovered in long distance over-charges. At the same time, customers who made heavy use of long distance bore more than their fair share of access line costs. The FCC now proposes to cover these costs through a system of flat (usage insensitive) subscriber fees to be phased in gradually over five years.

Whether the evolution of competition in telecommunications is attributed to technological breakthroughs, altered regulatory perspectives, or both, the consequences are the same. In a competitive environment prices for telephone services will be driven toward costs (including a competitive return on capital investment). That means any subsidies, inappropriate depreciation schedules, overtaxation of the entire network, or similar distortions will not be sustainable as competition spreads. The history of the opening of the interexchange markets to competition has been told before and need not be repeated here. We simply note that, although it was changes in FCC policy that initially opened the market to competition, in more recent periods it has been competition that has driven the actions that it has taken. In particular, the advent of interexchange competition has rendered the historical method for recovering NTS costs unworkable and has necessitated creation of an alternative method to cover these costs.

Another important change is the FCC's decision to preempt state control over intrastate rate-making and prescribe more rapid rates of depreciation for telephone plant and equipment. The time horizon implicit in the arguments of those who criticize more rapid depreciation guidelines is solely on the basis of their effect on price, and hence possibly universal service. It is too short, at least on a forward looking basis, while the reasons regulatory commissions prefer to deprecate investments over extended periods are easily understood from a political perspective, such policies hurt consumers.

Depreciation is a real cost of doing business and, as such, must be recovered by a company if it is to stay in business. Investors will find a company an unattractive investment if it fails to cover these costs, whether due to bad management or regulatory dispositions. The ultimate result of inadequate depreciation will be an inability to replace old or obsolete facilities with newer, technologi-
cally up-to-date equipment. That result, while possibly permitting lower prices in the short run, will threaten the continued availability of high quality service. Because inadequate depreciation thwarts the introduction of new tech-

ology, it may actually result in future prices to consumers well above what would have been possible under more enlight-
ened procedures. In short, excessively long depreciation schedules only serve to promote consumer welfare by keeping prices low, but they imply higher prices and poorer service in the future.

Effects on Costs

The staff of the FCC's Common Carrier Bureau has sought to estimate the general magnitude of the price changes associat-
ed with recent federal regulatory decisions. In addition to imposition of access charges and more rapid rates of capital
depreciation, the staff also considered the effects of changes in the accounting for costs incurred in the provision of
eMBEDDED and new station connections, the decision to phase out CPE revenue requirements out of the interstate jurisdic-
tion, the deterrence of embedded CPE and its transfer to ASAT, and growth in the proportion of inter- and intrastate toll usage relative to total telephone usage. Mandated changes in depreciation, CPE decisions, separations

requirements, while changes in the regulation of station

connections and the effects of a shift toward toll service reduce them.

The FCC's staff estimate of the cumulative monthly in-
crease in residential telephone exchange bills associated with these changes is $4.22 in 1984, growing to $8.20 by 1989. This represents a compound average annual growth rate for residential telephone exchange bills of about 7 percent from 1983 to 1989. To place this figure in context, recall that the real price of telephone service has been falling steadily over time. Using constant 1972 dollars, the price of service actually declined from $4.17 in 1960 to $4.69

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In 1981, only one category of consumption good had a smaller increase than telephone service during the inflationary 1970s and early 1980s (women’s clothing). While the consumer price index more than doubled over this period, phone prices rose 30 percent. The price increases implied by recent federal actions thus do little more than “catch up” with inflation, if indeed they even do that. When they are put in this perspective, it is difficult to believe they are likely to do any significant damage. Note that in 1970 telephone penetration nationwide already exceeded 90 percent.

When price increases of the magnitude estimated by the FCC staff are combined with (upwardly biased) demand elasticity estimates close to zero, the result is obviously a negligible effect on the level of telephone subscribership. This conclusion is strengthened by recognition that other factors will be simultaneously operating to increase demand for telephone service. The elasticity of demand for a product depends on the availability of substitutes. Demand will be more inelastic the fewer the substitutes. The measured inelasticity of demand for telephone service indicates an absence of close substitutes. This means that when prices rise people will be frustrated because they, in fact, have no good alternative to paying the higher prices. Thus, we conclude concerns over rising prices per se rather than threats to universal service are what principally motivate opposition to rate reform.

It is likely that few customers affected by the new policies will drop off the network, but customers who use long distance service infrequently will probably face higher bills even at the new lower rates. If this is a problem, it is primarily one of income distribution. Fear that unlimited local calling (at subsidized prices) may disappear is another concern. The availability of lifetime or other “bare bones” services specifically designed to protect universality does not assuage these concerns. The issues here are essentially distributive in nature and have only very little to do with possible threats to universal telephone service in the United States.

Policy Issues

Effects of Competition

The procompetitive policies for telecommunications that have been developing at the FCC and elsewhere in government over the past decade have been undertaken to increase the economic welfare of consumers. Recent discussion in Congress and among state authorities has focused almost exclusively on costs—and primarily on redistribution of existing costs, some of which should not even be classified as costs in economic terms. Reorganization of the telephone system along more competitive lines will not be costless, but there are reasons to believe that it will generate nonmarginal benefits for consumers.

Prices that reflect costs allow people to make choices in accordance with the costs they actually impose on society in terms of alternative resource uses forgone and the benefits they expect to receive. That promotes maximization of the economic benefits obtainable from use of society’s scarce resources and is the basis for the U.S. market-competition policy. Telecommunications was long exempt from that policy because it was supposed that economies of single-entity organization dictated a regulated monopoly industry structure. The judgment has now been made, at least implicitly, that those economies are insufficient or their existence insufficiently tested to warrant maintenance of the old structure. Dynamic inefficiencies thought likely to characterize the old structure’s prospective performance have been judged to outweigh efficiencies of single-entity organization. That the benefits of dynamic efficiency under competition will actually prove to be greater than forgone efficiencies of scale and integration, of course, remains to be seen.

There is some recent direct evidence illustrating how competition affects telecommunications. Delegation of CPF and the competition that has grown in its wake have brought benefits in the form of lower equipment costs and a wider variety of qualities and service features from which to select. A monopoly provider might have been able to offer these options to consumers, but under monopoly new products were, in fact, slow in coming, and both new and old products were high in price. The speed with which consumers are “voting” with their feet, not to mention dollars, for nontelephone-company equipment is powerful evidence and completely consistent with what we know to be true about competition’s generally salutary effects in the rest of the economy.

Long distance provides another example—still developing. The growth rates of the “other” common carriers and resellers confirm what we know to be the case in long distance pricing. Current pricing practices substantially overcharge for long distance service. That means not only that consumers must pay a large premium for the long distance calls they do make, but also that the premium itself leads them to forgo benefits they would obtain from greater utilization of long distance service such as would occur under cost-based pricing. Estimates of the deadweight economic welfare losses attributable to current inefficient pricing practices are enormous. The uses for and benefits to be derived from increased use of long distance go far beyond personal benefit. Medical doctors can call up services such as “Medline” and “Colleague” to obtain state-of-the-art
diagnostic research information. The legal reference service called "Lexis" provides the same kind of information for lawyers. Architects, engineers, and professionals of all kinds are using long distance communications to acquire information that enables them to supply better service at lower costs. The computer revolution is another source of greatly increased demand for telecommunications services, especially long distance. Credit card companies, airline reservation systems, and hotel/motel chains all use telecommunications-linked computer facilities to benefit consumers by reducing transaction costs.

As long distance rates fall, these service benefits can be made available on an increasingly widespread basis, including, in particular, to those people who live in rural areas and who are allegedly harmed by more efficient pricing of telephone services. We believe, to summarize, that there are important benefits to be obtained from promotion of competition in telecommunications.

Efficient Pricing and Network Bypass

Economic theory provides guidance about the best (economic welfare-maximizing) method for covering the cost of telephone service. Cost should be covered by pricing services above their marginal costs in inverse proportion to the elasticities of demand for the services. Since access costs are relatively insensitive to actual usage, and since demand for access to exchange facilities is less elastic than demand for usage, it is efficient to cover costs through flat fees for access and usage sensitive charges that closely reflect marginal costs of usage along different output dimensions (distance, length, time of day). The FCC's access charge order would substitute flat access charges to recover nontraffic sensitive costs for a system which attempts to recover those costs through usage sensitive charges greatly exceeding marginal costs. The FCC's proposal is thus a move toward more efficient pricing.

Those who oppose economically efficient pricing generally fail to recognize that failure to price efficiently will make most users worse off. Socking it to the big guys always sounds good to the little guys, until it is pointed out that attempting to sock it to the big guys will end up costing the little guys even more. Higher business telecommunications costs are passed along to consumers in the form of higher prices for the goods and services consumers purchase. The notion that costs can somehow be shifted from consumers to producers is false. Consumers bear all the costs of telephone service. The issue is whether costs should be borne by those who cause them to be incurred (either directly or indirectly) or whether they should be redistributed to other users who pay for by higher prices for virtually everything and everyone else.

The ubiquitous death-warrant warfare losses that inefficient pricing inflicts on consumers have been previously described. Inefficient pricing also causes productive inefficiency (resource waste). In the telephone industry, "bypass" is the "byword" on this topic. Bypass means nothing more than use of apparently less costly substitute services to avoid use of the basic regulated phone system. The concentration of telephone use is very high, with about 2 percent of all business customers accounting for 75 percent of telephone company business revenues. In these circumstances the actuality of even a few customers taking a significant fraction of their business elsewhere will have adverse cost consequences for customers remaining on the network. The irony is that much of the presently planned and current bypass would not occur if long distance services were priced efficiently. In the name of protecting consumers and, purportedly, universal service, the current surcharge/subsidy scheme constitutes the main threat to consumers and universal service. Unless drastic measures are taken, large businesses will find cost-effective ways of satisfying their communications needs. That is good for consumers who purchase the products of business but may be wasteful from an economic perspective if motivated by artificially high prices.

Congress perceives that bypass is the real threat to universal service, but instead of deterring unneeded bypass by confronting decision makers with prices that accurately reflect costs, some members of Congress propose to tax bypass technologies. On one hand, that solution will not work given sufficiently large loopholes in the tax proposal. On the other hand, if the solution "works," then we are really in trouble. Technical advance is the primary reason we have low cost, high quality, widely available telephone service. Technical advance does not occur in a vacuum. The extent and direction of technological progress reflect prior investments in research and development, which in turn reflect the structure of incentives embedded in market prices. Technical advance is like any other good: Make it more expensive and people will demand less of it; reduce the reward to investments in new technology, and people will invest less in the activity. Congress in essence proposes to preserve universal service by killing the goose that figuratively laid the golden egg. As Leland Johnson (1983, p. 50) has remarked: "Such a clear-cut case of penalizing the development of new and lower-cost technologies raises major issues of national economic policy."

Equity Considerations

Alfred Kahn (1983, p. 7) has observed: "Clearly there are possible areas of public policy in which conceptions
of fairness may conflict with economic efficiency. But it is by far the greater wisdom to recognize that, for the most part, the major departures from economic efficiency in our public policies today are also demonstrably unfair; and that, for the most part, movement in the direction of economic efficiency is also compatible with increased fairness. It is fair, as a general proposition, to impose costs on people insofar as they impose costs on society.\footnote{Note that in this view all prices not scaled to income differences are "progressive." Any price represents a larger proportion of a low income than a high one. Consumers may also differ in their use of the service, so that even if everyone had equal incomes, there would still be an "equity" problem because consumers who use the service more face a lower average charge, the flat fee divided over a larger number of units.\footnote{Consider the application of such equity principles to the consumption of automobile services. They imply that these services are "inequitably" priced because unit costs are higher for an individual who does little driving compared to one with a similar car who drives a lot. By the same reasoning, automobiles are inequitably priced because their prices constitute a larger percentage of income for a person with a small income compared to one with a large income. It has been suggested that it is unfair for a person who makes no long distance calls to have to pay a long distance access charge. This is analogous to arguing that people who do not own telephones should not have to pay the full cost of their cars. Of course, application of the same principle also implies that local unmeasured service is very unfair since average costs for people who only use their phones in an emergency are much higher than for those who have a "normal" pattern of use; but this is not often drawn by the advocates of economic inefficiency.\footnote{Note that traffic sensitive automotive costs are higher in some parts of the country than in others. In the North, for example, snow tires are often needed for winter driving, whereas in the South they are not. Should southerners therefore be compelled to subsidize snow tire purchases by northerners? If they are, it is simple to come up with some justification that many more Yankee autos will be equipped with snow tires. Of course if southerners must subsidize northerners because the North is cold, "equity" demands that northerners be compelled to subsidize southerners because the South is hot!}

The FCC's access charge plan is a "movement in the direction of economic efficiency" and attempts to "impose costs on people in so far as they impose costs on society." Some have nevertheless claimed that the plan is inequitable. Their argument is premised on the observation that since users differ in income, a flat fee constitutes a larger percentage of income for the poor compared to the rich and is thus "progressive," as is any lump-sum tax. Note that in this view all prices not scaled to income differences are "progressive." Any price represents a larger proportion of a low income than a high one. Consumers may also differ in their use of the service, so that even if everyone had equal incomes, there would still be an "equity" problem because consumers who use the service more face a lower average charge, the flat fee divided over a larger number of units. Consider the application of such equity principles to the consumption of automobile services. They imply that these services are "inequitably" priced because unit costs are higher for an individual who does little driving compared to one with a similar car who drives a lot. By the same reasoning, automobiles are inequitably priced because their prices constitute a larger percentage of income for a person with a small income compared to one with a large income. It has been suggested that it is unfair for a person who makes no long distance calls to have to pay a long distance access charge. This is analogous to arguing that people who do not own telephones should not have to pay the full cost of their cars. Of course, application of the same principle also implies that local unmeasured service is very unfair since average costs for people who only use their phones in an emergency are much higher than for those who have a "normal" pattern of use; but this is not often drawn by the advocates of economic inefficiency. Note that traffic sensitive automotive costs are higher in some parts of the country than in others. In the North, for example, snow tires are often needed for winter driving, whereas in the South they are not. Should southerners therefore be compelled to subsidize snow tire purchases by northerners? If they are, it is simple to come up with some justification that many more Yankee autos will be equipped with snow tires. Of course if southerners must subsidize northerners because the North is cold, "equity" demands that northerners be compelled to subsidize southerners because the South is hot!}

The question of Subsidies

The facts strongly suggest that access charges will, on average, have a very small effect on telephone penetration rates. Obviously, no one is an average individual or lives in the average place. Costs of providing access tend to be higher in rural as compared with urban areas. Some have sought to use these cost differences to justify a policy of geographic cross-subsidization, and the FCC itself proposes a fund to subsidize high cost areas. Cost differences provide an exceedingly weak basis on which to justify subsidies. There are innumerable "cost" differences between urban and rural areas. To focus on one good and to argue that a subsidy is justified because that particular good is more costly in one area than another is extremely myopic. The air tends to be cleaner in the country. Does that mean that citizens of rural states should be compelled to subsidize people in New Jersey because of the high cost of clean air in the Garden State?

The FCC has proposed creation of a universal service fund to reduce geographic cost disparities, but from an economic perspective there are three problems with the proposal. First, the fund is to be raised by a surcharge on a larger number of units. Consider the application of such equity principles to the consumption of automobile services. They imply that these services are "inequitably" priced because unit costs are higher for an individual who does little driving compared to one with a similar car who drives a lot. By the same reasoning, automobiles are inequitably priced because their prices constitute a larger percentage of income for a person with a small income compared to one with a large income. It has been suggested that it is unfair for a person who makes no long distance calls to have to pay a long distance access charge. This is analogous to arguing that people who do not own telephones should not have to pay the full cost of their cars. Of course, application of the same principle also implies that local unmeasured service is very unfair since average costs for people who only use their phones in an emergency are much higher than for those who have a "normal" pattern of use; but this is not often drawn by the advocates of economic inefficiency. Note that traffic sensitive automotive costs are higher in some parts of the country than in others. In the North, for example, snow tires are often needed for winter driving, whereas in the South they are not. Should southerners therefore be compelled to subsidize snow tire purchases by northerners? If they are, it is simple to come up with some justification that many more Yankee autos will be equipped with snow tires. Of course if southerners must subsidize northerners because the North is cold, "equity" demands that northerners be compelled to subsidize southerners because the South is hot! Second, the FCC proposal would target aid to high cost areas with perverse incentive effects for economic efficiency. Targeting aid to high cost areas discourages cost control, whether through efficient management or use of cost-minimizing technologies, including substitutes for conventional telephone such as radio. Third and most important, the proposed system of subsidies is targeted to high cost areas rather than low income households. The threat to universal service, if there is one, is that low income consumers will be forced off the system, not that long distances will not be allowed to have to pay the full cost of their cars. Of course, application of the same principle also implies that local unmeasured service is very unfair since average costs for people who only use their phones in an emergency are much higher than for those who have a "normal" pattern of use; but this is not often drawn by the advocates of economic inefficiency. 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that the elderly are harmed by access charges ignores that the elderly do slightly more than the average amount of long distance calling and would presumably do even more if the price were lower.75 Many elderly people are separated from their families and friends by long distances and would benefit from the FCC's access charge plan by being able to make and receive a greater number of long distance calls of longer duration.

There are elderly people who are poor, to be sure, but it is their indigence rather than their age which argues for their support. It is not clear why support for the poor should take the form of below-cost telephone service rather than dollars. That adverse effects on the poor justify keeping the price to everyone below cost is bewilderingly naive, but as Bastiat noted long ago, "the state is the great fictitious entity by which everybody seeks to live at the expense of everyone else." Unless one is prepared to argue that everyone's food, fuel, and television set bills should be subsidized (by whom?) because higher prices for these items hurt the poor, one cannot convincingly argue against access charges on the poor.

A universally available subsidy such as we have currently built into the basic system of charges to all consumers is an excessively costly and ultimately indefensible way of meeting the legitimate needs of those few whose access to telephone service might be threatened by cost-based pricing. It is excessively costly because to maintain it will require forgoing the benefits of competition and technical advance. It is ultimately indefensible because eventually the users providing the subsidy, especially major users, will find ways of escaping the system.

Subsidies, if deemed necessary, should meet two criteria. First, they should be raised in as nondistorting a way as possible, if not through general tax revenues (the ideal), then perhaps by an addition to customer access line charges. Second, financial payments or lifetime rates should be made available to those who need them, not to everyone. The difficulty of identifying those eligible for subsidies—whatever form they take—is often magnified unduly by opponents of targeted programs. We believe it would be both fairer and far less expensive to formulate a program aimed at low income individuals rather than high cost areas.

Summary

Consumers pay all the costs of providing telephone service. That is true now, and it will be true if the FCC's access charge plan or any other pricing scheme is implemented. Under current practice, below-cost prices for local telephone service are paid for by above-cost prices for long distance services and for all other goods and services whose production and distribution entail use of long distance service. A promise to keep the price of local telephone service from rising also implies a promise to keep the prices of long distance and other goods and services from falling. It also implies that a person who makes no long distance calls is not necessarily being subsidized under the current system, for the overcharges on all other goods and services consumed may more than offset the difference between the actual cost of access and the actual price paid.

Because consumption varies with income, it is probably true that an income redistribution from higher to lower income consumers is occurring under the current system. It occurs because surcharges are embodied in the prices of virtually all goods and services, and higher income individuals, up to a point, purchase more goods and services. Note, however, that these redistributive benefits are currently being produced in an extremely inefficient way (not to mention their being "disguised" quite arbitrarily). If subsidization were more effectively rationalized, the same benefits could be provided to needy individuals at far less cost or, alternatively, much larger benefits could be provided. Moreover, as has been widely remarked, the current system of subsidies will become increasingly unsustainable given the spread of competition.

The available evidence on the demand for access, coupled with what we know about the likely magnitude of cost increases, indicates that threats to universal service are minimal or nonexistent. Should any problems arise, there are various ways of handling them that are consistent with the basic thrust of the FCC's procompetitive decisions. We conclude that proposals to roll back or substantially alter the thrust of the FCC's access charge plan are ill-advised in general and cannot be justified as legitimate responses to universal service threats in particular.

Notes


3. There can be 'too much' of any good thing which is not free (costless). The economically efficient level of telephone subscription is that level at which the marginal social value of an additional subscriber equals the marginal social cost. For the United States, there is evidence that the socially efficient level of telephone subscription occurs at less than 100 percent penetration. See William S. Reese (1983).
4. Jeffrey Rohlf (1973) has estimated that the marginal cost of Interstate long distance message services was about 30 percent of price in 1976.


6. See comments throughout the Joint Board proceeding (CC Docket 80-286). Several commentators remarked that the proposed subsidy plan would reward inefficiency and penalize efficient operations. Many also noted the tenuous connection between subsidy and need in the proposed plan.

7. James M. Griffin (1982) estimates the economic welfare losses associated with current inefficient pricing practices to be on the order of one trillion dollars per year. He concludes (p. 66) that "the existing degree of cross-subsidization of local service by long-distance service cannot be justified by welfare economics."

8. See Milton Friedman (1971).


10. Estimates range from 0 to -0.24, with most falling below -0.19. As the FCC staff concludes in its report of findings in Docket No. 83-788 (1983, p. 28): "These studies using the best and most recent data and having the best specified theoretical framework yield estimates at the lower end of this range."

11. On the basis of 1970 data, Perl estimated an elasticity of -0.09. On the basis of 1980 data, he found that elasticity had fallen to -0.07.

12. For example, use of the Perl estimate based on 1970 data to gauge the effect of price changes in 1980 would, given the magnitude of the elasticity parameter actually measured using 1980 data, result in overstatement of the likely effect by a factor of three.

13. See Table 3 in the text and its note a.

14. In Allman's model the measured elasticity fell from -0.17 to -0.02 when measured service offerings were included in the specification of the model. Perl also finds that the availability of measured service reduces the estimated elasticity of demand for access.

15. Measured service offerings are available to about 70 percent of the residential subscribers served by Bell Operating Companies.

16. Taylor's "highly subjective" estimate is that the true elasticity of demand for access lies between -0.01 and -0.19. See also Table 3 in the text.


18. The case usually cited in support of this proposition is the so-called Above-890 decision, "in the Matter of Allocation of Frequencies in the Bands Above 890 Mc.," Report and Order, 27 FCC 309 (July 1989).


20. Telephone companies are legally entitled to recover their historical costs. Whether book costs exceed true economic costs and whether companies would, in a competitive environment, be required to write off rather than try to recover these costs are issues subject to dispute. See Nina M. Cornell et al. (1981).


22. A summary of policy decisions is given in Attachment 9 to the FCC staff study, FCC (1983).


25. Costs of providing exchange access may be higher in rural areas, but so are the benefits of lower prices for long distance calling.


27. This assumes no lump-sum taxes are permitted and that cross-elasticities of demand among different services are zero. If the relevant cross-elasticities are nonzero, the inverse elasticity rule is not applicable, but an analogous rule may be easily derived. See Baumol and Bradford (1970, pp. 256-67).


29. See the comments of the FCC in its letters to Senator Goldwater on S. 1660 (October 31, 1983) and to Representatives Brayhill and Ritter on H.R. 4102 and H.R. 4286 (December 5, 1983).

30. See Nina W. Cornell et al. (1980).

31. This argument was made explicitly by Dallas Smythe in his oral comments on the initial presentations in an earlier session of this conference. For a simple analysis, see Steven T. Call and William L. Holahan (1983, p. 445).

32. The principle has been given humorous expression by Calvin Trillin (1983), who notes: "I bought my tuxedo in 1954, when I was a thrifty young undergraduate, because I had added up the number of black-tie events I would have to attend during college, divided the cost of a tuxedo by that number and concluded that I would be better off buying a tuxedo than renting one . . . . As it turned out, there have been a number of occasions to wear the tuxedo since graduation . . . . and every time I wear it the cost per wearing decreases. This New Year's Eve, for instance, wearing my tuxedo is going to cost me only about 48 cents." Life is unfair, permitting John to attend more parties than Ken, for that means John's tuxedo costs less than Ken's.

33. See the comments of their telephone companies and state public utility commissions or subsidies to encourage universal service in the Joint Board proceeding (CC Docket 80-256).


35. See the toll usage study by Susan J. Devlin and I. Lester Patterson (1981).

36. As Kahn (1983, p. 8) argues: "There are consumers who want to make a lot of calls in an extended area at no extra charge, and there are others who happen to live in the country, or on the borders of local calling areas, whose equally short-distance calls are subject to inflated toll rates: to imply that the interest of both of these would be similarly adversely affected by a more efficient pricing system is ridiculous."

References


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ACCESS CHARGE THEORY AND IMPLEMENTATION: A SLIP TWIXT CUP AND LIP

Michael D. Pelcovits, Nina K. Cornell, and Steven R. Brenner

From the inception of its inquiry into whether the "public interest requires that interstate message toll telephone service . . . should be provided on a sole source" or competitive basis, the FCC has been grappling with the issue of access charges. In the first Notice of Inquiry in Docket 78-72 almost six years ago, the FCC proposed "to determine what reimbursement interstate services should make to local operating companies for the use of local plant, on a cost causational basis, what additional charges, if any, should be levied on interstate services to support local exchange services; and whether and how these charges can be equitably imposed on all interstate services." While it is likely that there will be a number of refinements, some possibly major, the FCC in its two recent orders, the Third Report and Order of February 28, 1983 ("Third Report"), and the Memorandum Opinion and Order of August 22, 1983 ("Reconsideration"), has established a structure that is likely to underlie access charge tariffs for years to come.

The access charge structure created by the FCC addresses the three concerns of the Initial Notice in Docket 78-72, focusing sharply on the first. Indeed, the FCC has supported its decisions as being economically efficient. Using the criterion of economic efficiency, this paper examines one aspect of the proposal laid out in the Third Report as amended in the Reconsideration, namely, the pricing of the access
received by AT&T for its message toll service (MTS) and the access received by the other common carriers (CCCs) for their MTS-like services.

The FCC's July Access Charge Plan

The FCC's access charge decisions propose to alter the way in which interexchange carriers are paid for use of the local exchange plant to originate and terminate interstate toll calls. Prior to the divestiture of the Bell Operating Companies (BOCs) by AT&T, local exchange companies billed customers for their use of AT&T's MTS and WAATS, pooled the revenues collected, and then shared them according to complicated formulas prescribed in the Separations, Settlements, and Division of Revenues orders. CCCs billed their customers themselves and paid local exchange companies directly according to the terms of the MENA and similar tariffs. Telephone users of MTS, WAATS, and the BOC's similar services paid only if they made (or planned to make) long distance calls.

The separations formulas were established to determine what share of local exchange plant should be allocated to the interstate jurisdiction and what share to the intrastate. The formulas applied to both traffic sensitive (TS) and nontraffic sensitive (NTS) plant. These formulas will continue to be the basis on which local exchange companies set their revenue requirements for interstate access charges. Access charges, however, are to replace the Settlements and Division of Revenues orders.

As long as local telephone companies continue to have a virtual monopoly over access to most end-users, the structure and level of their rates will remain regulated. As long as local telephone company revenue requirements are separated between intrastate and interstate jurisdictions, the FCC will have the opportunity to exercise its monopoly power over local exchange companies over interstate retransmissions. Thus, the FCC must try to ensure that overall rates are not set at monopoly levels and that interstate access charges are not structured to allow price discrimination.

The access charge structure established by the FCC in the Third Report and Reconsideration is based on the presumption that the cost of the interstate services' use of local exchange facilities is equal to the traffic sensitive (TS) cost developed by the Separations Manual. The FCC plan called for the companies providing interstate services to pay these costs over the long run. This is the way the FCC dealt with the first concern of Docket 78-72, namely, 'what reimbursement interstate services should make to local operating companies for the use of local plant on a cost causational basis.'

The nontraffic sensitive (NTS) costs assigned to the interstate jurisdiction are assumed not to be caused by interstate usage and, therefore, in time most of these costs were to be recovered from the local exchange customer (the "end-user"). During an interim period, however, a large but declining share of these costs was to be recovered from the interexchange carriers in order to prevent the abrupt imposition of high end-user charges. In this way the FCC addressed the concern about support to local exchange services. Finally, the FCC brought all interstate services under the same umbrella to deal with at least part of its concern about the "equitable" imposition of access charges. In addition to a variety of provisions dealing with private line, foreign exchange, and WAATS, the Order imposed the same tariff structure, and nearly the same charges, on the CCC's MTS services as on AT&T's MTS.

Given that the interexchange carriers were to cover only the traffic sensitive costs, there are three main instances in which the FCC deviated from the path that would further the goal of economic efficiency in the prices that interexchange carriers must pay to local exchange carriers for origination and termination of their MTS or MTS-like services: the failure to include a peak/off-peak differential, the failure to deal at all with economic versus non-economic costs, and the failure to set an appropriate differential in the rates charged for different qualities of access. The access charge theory Page 345

Peak Period Pricing

Peak or busy hour usage determines the total amount of TS plant a local exchange company needs to maintain a given probability that a call will not be blocked for lack of capacity. It would be consistent with both economic theory and previous FCC orders to set higher access charges to interexchange carriers in peak than in off-peak periods. The interexchange carriers, in turn, could be expected in most cases to pass these rate differentials, as well as any cost differentials of their own, along to their customers, which would alter their calling patterns to some degree and lead to more efficient use of local plant. It is even conceivable that an off-peak discount would promote new services.

It is particularly anomalous that the FCC failed to include an off-peak discount in access charges, as many telephone companies are coming in with local measured service plans that include time-of-day as one of the price variables. As much of the same capability in the local exchange plant and equipment required to measure local exchange usage is needed to measure access usage by interexchange carriers, these local measured service options demonstrate that a peak/off-peak differential would not impose significant additional costs on the local exchange companies.
Moreover, the FCC has insisted on such discounts as a condition of approving tariffs for other services, such as WATS. It would not be difficult for the FCC to correct this aspect of its Order. As a first approximation it could use the discounts currently in place for long distance switched toll services. For those few companies for which the additional equipment might be a hardship, a waiver could be granted.

The Problem of Uneconomic Costs

The FCC's access charge plan also deviates from an economically efficient one in its explicit acceptance of the interstate revenue requirement as synonymous with economic costs. As a general matter, the Order assumes that both the other costs of the local telephone companies and the separations formula used to assign a portion of them to the interstate jurisdiction are valid representations of economic costs.

Only if the underlying cost amounts are economic costs can any rates that recover those costs be economically efficient. The costs data used for separations are the accounting costs of the local exchange companies, namely, the original prices paid less depreciation. These costs are highly unlikely to be the economic costs of local exchange service for at least four reasons.

First, the original prices paid, particularly in the case of the BOCs, were not prices set in a competitive market. The BOCs acquired most of their plant and equipment from Western Electric, which, like the BOCs, was owned by AT&T. Western Electric sold almost exclusively to AT&T and the BOCs but, unlike them, was not regulated. Such a combination created strong incentives for Western Electric to sell its equipment to BOCs at prices higher than those that would prevail if there were competition. Thus, the initial cost to the BOCs of plant and equipment may not ever have been the economic cost of that equipment, but something in excess of it.

Second, the quantities of plant and equipment acquired, whose costs form the costs to which the separations formulas are applied, may not have been the economically efficient quantities. It is likely that too much plant and equipment was purchased and installed, as regulated monopolies have incentives to expand the database as one means of maximizing profits. Thus, this incentive also would tend to make accounting costs higher than economic costs.

Third, the specific technology embodied in the plant and equipment acquired by the local exchange carriers may not have been the most efficient technology at the time the plant was installed or the equipment acquired. A regulated firm, seeking to maximize profits subject to regulatory constraints, has an incentive to select technologies that may not be as optimal as those chosen if the firm were not regulated. Moreover, these incentives also apply to the choices made over time as technology changes.

Fourth, the depreciation rates used almost certainly have not been the economically efficient rates, but something slower. Despite growing attention to this area and some acceleration, depreciation rates still are slower for telephone companies than for other similarly situated but unregulated industries. For example, digital switches, which are a form of computer, have depreciation rates that are much longer than the rates used by other industries for computers. Unduly slow depreciation rates also make accounting costs today higher than economic costs.

All of these problems suggest that the accounting costs of the local operating companies are significantly above their economic costs. Even so, the access charges could be efficient if they were set to recover only the economic costs. The costs they are to recover, however, are determined by the separations formulas, which were arrived at through a process of political negotiations between Federal and state regulators, with help from the industry. Economic efficiency was not a centerpiece of those negotiations. Moreover, the way the formulas work makes it unlikely to yield an economically efficient outcome by happenstance.

The separations manual calls for local exchange companies to divide the accounting costs of all their plant and equipment used in common for local and toll between the state and interstate jurisdictions, with relative use as the allocator. Even when the amount of plant varies with usage, however, relative use is not the only factor in determining the cost of plant in place. At least some of the plant used in common for local and for the toll service provided by AT&T is more costly per unit of capacity than it would be if it had been built solely for local exchange.

The separations formulas recognize this, but not necessarily in an appropriate way. Instead of estimating the additional cost imposed by AT&T's toll service and assigning that directly to toll, the formula incorporates a "Toll Weighing Factor" by which a minute of toll use counts as more than a minute of local use. Only by a pure and highly improbable accident would these two approaches yield the same result.

All of these problems with the separations process indicate that the underlying pool of costs that access charges are designed to recover are not economic costs. Thus, designing an economically efficient way to recover them, particularly in face of the erosion of complete local exchange monopoly, may not be possible. The implications of who should handle the hot potato of uneconomic costs are far reaching and ultimately beyond the scope of this paper, but at least in this regard the FCC's access charge plan is not
consistent with economic efficiency.

**Different Prices for Access of Different Quality**

The third key problem with the access charge plan of the Third Report as amended by the Reconsideration is the pricing of access given only to AT&T for MTS and that given to the OCCs for their offerings that compete with MTS. AT&T has long been connected to the local exchanges by trunks, and the local exchanges at either end of a long distance call have done more than simply interconnect a user to AT&T’s toll switch. The local switches have been designed to treat toll calls through AT&T differently from local calls.

**Quality Differences in Access Arrangements**

When an end-user makes a toll call on AT&T, the user’s local switch collects the number being called, sends it on to AT&T (usually more rapidly than the caller sent it, thereby economizing on AT&T’s switching costs), and either keeps a record of the number from which the call was made or sends that number to the next switch (for billing purposes). The local system ensures that high standards over technical characteristics such as noise, echo, and signal loss are maintained between the local exchange switch and AT&T’s switch.

The local exchange serving the recipient of that call also performs services for AT&T. When the recipient answers the phone, MTS or her local exchange switch signals back to the switch serving the caller to start timing the call and signals again when the recipient hangs up. The recipient’s local exchange company also ensures the same technical parameters of service between itself and AT&T as the caller’s exchange.

The interconnections that have been given to the OCCs offer none of these services. The caller’s local exchange switch does not pass on to the OCC switch the number called. Rather, callers must enter it after they receive a dial tone from the OCC switch. They can do so, only if they can generate tones, rather than digit pulses. The recipient’s local exchange switch does not tell the OCC when the call is answered or when the recipient hangs up. Nor does the local exchange company maintain the same level of technical quality between itself and the OCC’s switch as it does between itself and AT&T’s switch.

These differences may not be permanent. The Modification of Final Judgment (MFJ), under which AT&T agreed to divest itself of the OCCs, requires the latter to provide to all interexchange carriers access that is "equal in type, quality, and price to that provided to AT&T and its affiliates." The MFJ does, however, permit waivers, and these waivers, if granted freely, could affect a large number of customers. It is still unclear whether the OCCs will receive equal access to the local exchange subscribers served by non-Bell local exchange companies, with the possible exception of those served by GTE.

**Access Pricing**

Until now, the unequal access received by OCCs has been offset partially, although not completely, by somewhat lower prices than they have had to pay for access. The ENFTA tariffs paid by OCCs are lower than the payments made by AT&T to the local operating companies through the Settlements and Division of Revenues process, in both the Third Report and the Reconsideration, the FCC recognized that AT&T and the OCCs receive access to local exchanges of different quality and argued that the amount each paid for access should reflect this difference. The FPC decided that AT&T should pay a premium over what the OCCs pay for its premium quality access. The OCC’s access charge proposal, however, changed the relative prices paid per minute of local exchange use by AT&T and the OCCs, lowering AT&T’s costs while raising the OCCs’. One issue in judging the efficiency of the OCC’s carrier access charge proposal is whether that proposal correctly sets the price for AT&T’s access relative to the price for the OCCs’ access arrangements. This question has two major components: Is it economically efficient to have any difference? If so, how large should the difference be?

The issue of whether and how much more AT&T should pay for its superior access may be largely a transitional question if eventually the OCCs should enjoy equal quality interconnection, at least to the great majority of local exchange customers. Nonetheless, it has important implications for the efficient provision of interexchange telephone services. The access charges paid by AT&T compared with those paid by the OCCs will help shape the transition from a regulated market with controlled entry to a competitive market in which no competitors are forced to accept inferior interconnection. Market competition between carriers with equal access will promote efficiency. Thus, one criterion by which the access charge plan should be judged is whether it assures an efficient transition from the present, nonmarket environment, which is not the result of market forces, to an environment in which competitive market forces can operate efficiently.

**Differential Prices for Access**

In the current debate over the appropriate prices to charge AT&T compared with those to charge the OCCs, there is implicit agreement that AT&T’s access is more valuable than the access provided to the OCCs. The area of disagreement
is whether it would be more economically efficient for all carriers to pay the cost of supplying the type of access they now use, regardless of the differences in value, or whether those value differences should be reflected in the prices even if there are no cost differences. In the Third Report, the FCC justified departing from a purely cost-based access charge for access of different qualities by using the concept of opportunity cost as revealed by an auction of a scarce resource:

If the type of access received by AT&T can be provided only to one carrier (at least in the short run), then even if it does not cost much to provide this access to that one carrier, this access has an "opportunity cost" that is equal to the amount that other carriers would be willing to pay for this preferred access. The cost of providing the favored carrier with this unique level of access includes the denial of this access to other carriers. Those carriers who receive the level of service that could be provided to any number of carriers would pay the full costs of this service. Carriers who receive the premium access service would pay the observable costs and an additional amount reflecting these opportunity costs. A surcharge for such premium access could theoretically be computed to reflect such opportunity costs, but it would probably be necessary to conduct an auction to determine the amount a carrier would pay for such premium access. We have decided that an auction would not be feasible. We will, however, assess a charge upon AT&T and its interexchange partners that will reflect an estimate of premium value. We will describe that charge as the "premium service charge." 5

The Reconsideration provides a further explanation of the opportunity cost concept in a footnote:

The opportunity cost of scarce assets is a major equalizer in many economic endeavors. For example, farm land may expect to reap larger harvests from the land, but also must pay high rents. Or balance, rents adjust to compensate for differentials in land quality. By establishing the price of a scarce resource, be it either land or premium access, at an amount that an excluded party would have been willing to pay, competitors are put on an equal footing and the resource is put to its most efficient use. 6

The FCC was quite correct that opportunity cost, which incorporates not just production costs but also relative values, serves a number of important economic purposes. The FCC focused on two of those functions: ensuring that resources are put to their most valuable use and equalizing the position of competitors in markets. When the quantity of the scarce resource can be increased over time, opportunity cost can also serve a third function: directing the necessary resources into production of the scarce resource by increasing the profits earned by those currently producing it.

Opportunity cost can perform the first function—ensuring that the scarce resource is put to its most valuable use—only if that resource actually can be reallocated from one user to another. This is not currently the case for premium quality access. As the FCC noted in the Reconsideration:

In fact, such an auction would be a practical impossibility because premium interconnection cannot be severed from AT&T and offered to another carrier. Nor could an auction be simulated since carriers would have no incentive to make realistic bids. Even if premium access could be severed from AT&T, the resulting temporary dislocations to the entire telecommunications industry would be too costly. Also, given the relative size of AT&T and other bidders, others could probably not reasonably be expected to bid against AT&T for premium interconnection. 7

Opportunity cost can only perform the second function—the equalizing function—when competitors are on an equal footing in all other respects besides access to the scarce resource. Again, this is not the case with premium quality access. AT&T is in a uniquely advantageous position to profit from the use of its premium access. This is true not only because its network has been configured for this kind of access, unlike the networks of the OCCs, but also because its past monopoly over all access and its present monopoly over premium access have resulted in its having both an overwhelmingly dominant market share and the network capacity that goes with it. In short, past history ensures that, in the short run, premium access is worth more to AT&T than to any OCC. Thus, even if the OCCs could use premium access and the other practical difficulties of a real or simulated auction could be overcome, AT&T would not have to outbid the OCCs by the full additional value to them of premium access. The
opportunity cost that AT&T would have to pay in an auction for premium access, therefore, would put the OCGs with inferior access on an equal footing with AT&T. It would leave AT&T with substantial profits and advantages from premium access to enjoy and to use in competing with the OCGs.

Moreover, even if some means other than an auction could be devised for arriving at the full value to AT&T of premium quality access, charging it a premium equal to that value cannot put AT&T and the OCGs on a completely equal footing in the same sense that market prices for farmland put farmers on an equal footing. The differences in access force the OCGs to produce a different product from that supplied by AT&T, rather than forcing them to produce a homogeneous product at higher cost as is true with farmland.

Opportunity cost can serve its third function—inducing an expansion in the supply of a scarce item—only when there are no nonmarket barriers to such expansion. This situation, however, is not the case with premium quality access. AT&T alone has premium quality access, not because of any market determination that this use of resources is in any way efficient, but because, as a regulated firm controlling the bottleneck resource of access, it was able to refuse equal access to competing interexchange carriers. The barrier to expansion in the supply of premium access has not been lack of profitability from producing access, but monopoly ownership over a bottleneck resource.

The issue, therefore, is not strictly one in which the normal notion of opportunity cost can be relied on to determine what would be the more efficient pricing structure. Rather, the issue is what the efficiency effects are if AT&T is allowed to retain the advantages that flow from its monopoly over premium access compared to the efficiency effects if it is not allowed to retain those advantages.

In this light, several useful economic purposes are served by allowing as far as possible the monetary advantage to AT&T of premium access.

First, a premium based on the value to AT&T of premium access puts the maximum market pressure on AT&T to be efficient in its supply of interexchange services. Regulation cannot be as effective as competition in forcing AT&T to be efficient. The less AT&T pays for premium access, the more of a competitive cushion it will have to retain practices that are not efficient. Such inefficiencies will reduce profits, but it is not inconceivable that AT&T might accept such a trade-off, at least in the short run, especially if it faces regulatory restrictions on its profitability. Any such inefficiencies are social costs.

Second, a lower premium that allowed AT&T to retain more of the monetary advantages of premium access would extend the time before the structure of the market for interexchange services is effectively competitive. If AT&T is allowed to retain the monetary advantages of premium access, it will, at a minimum, slow the growth of the OCGs while they must use inferior interconnection. The OCGs have been able to carve out a small market position despite inferior access, but they have done so while paying less for their inferior access under the EMFIA tariffs than AT&T implicitly has paid for premium access under Separations and Settlements. If the premium access charged AT&T does not at least maintain the current differential between the EMFIA tariff and what AT&T pays, the OCGs either will have to raise prices to cover their increased cost, which means they would lose customers, or they will have to absorb higher costs. Their business will be hurt, and their profits will decline sharply.

Thus, the more of the advantages of premium access that AT&T retains, the smaller will be the competitive fringe challenging AT&T when equal access is achieved. Since it will take time for the competitors to attract customers and build capacity, a smaller competitive fringe, in turn, extends the time before market forces by themselves can fully constrain AT&T pricing and efficiency. Indeed, market forces might be completely constrained by the time of equal access if the premium is large enough to deny AT&T most of the monetary advantages of premium access.

In short, allowing AT&T to retain the advantages of premium access means incurring the social costs of an unlosely uncompetitive market at the time equal access is fully available. These social costs might flow from AT&T exerting market power if it is not constrained by regulation. Alternatively, they could take the form of the costs of regulation, including diminution of consumer welfare to the extent that regulation is a less effective constraint on dominant firms than competition.

Third, the social costs of allowing AT&T to keep the advantages of premium access may go beyond simply delaying the day when the market is competitive. Obviously, setbacks to the OCGs because of inappropriate pricing for access say nothing about the efficiency with which they provide service between their own switches relative to AT&T in a world of equal access. Yet, in the real world of Imperfect Information, such losses could affect their ability to compete after equal interconnection. The likely reaction of capital markets to sluggish performance by the OCGs during the period of unequal access would exacerbate the problem of slowing the "running start" of the OCGs, which they otherwise would have at the time equal access is in place.

Interexchange service is a very capital-intensive business. If the OCGs are to compete effectively with AT&T, they need access to large amounts of capital. The current willingness of capital markets to finance OCG expansion is not based on long experience with or great depth of knowledge about competition in this industry. Losses during the period
of transition might cause capital markets to revise sharply
their evaluations of the future profitability of competitors
to AT&T. That change could threaten the OCCs' ability to
raise capital at competitive rates that properly reflect
the risk of such investments, since equal access is not.
Reduced net revenue will directly reduce internal sources
of capital. Losses also could hurt external sources. If
capital markets had perfect information, perhaps it would
realize that current business difficulties of the OCCs would
say little about their competitive fortunes once they had
equal access. Similarly, capital markets should be willing to finance
current losses if that investment allowed the OCCs to maintain
competitive prices until they had equal access. Once equal
access was achieved, capital markets would pay off once
equal access were achieved. Capital
markets, however, cannot have such perfect information. It
is unreasonable to claim that current losses due to a reduced
differential between what they would pay for access will not affect the OCCs' cost of capital.
Finally, just as significant as the direct effects of
allowing AT&T to keep the monetary advantages of premium
access would be the effect on the pace of introducing equal
access. The MFJ has set a timetable for the BOCs to provide
equal access. That timetable allows for many exceptions,
which the OCCs are likely to seek more readily if they do
not face demand for equal access, and which if granted would
then be likely to continue longer. Furthermore, the term
'equal access' is simply too broad and does not encompass
many of the features of the network that require the active
participation of the affected parties to ensure fair treatment.
Only if the OCCs are active and there is genuine
in such participation. In addition, equal treatment of all
long distance carriers will not be complete until the indepen-
dent telephone companies, not bound by the MFJ, also offer
the same quality interconnection to all carriers. If
the OCCs are not there to advocate this position, equal access is
unlikely to become the standard for which
In short, if AT&T is allowed to keep more of the monetary
advantages of premium access, it will harm the transition to
efficient market competition. In general, firms are concerned not about protecting competitors, but only
about protecting competition. Normally, that means policy
makers should not be concerned with protecting competitors
that the market shows are less efficient from ones that the
market shows are more efficient. That dictum must be inter-
preted carefully in these circumstances. Policy
makers should be concerned that OCCs as a class are not damaged
during the transition to equal access because of disadvantages
that are not a result of their own inefficiency, but only
circumstances (namely, access) imposed on them. Further-
more, the source of these disadvantages is supposed to
disappear, and care should be taken that their effect is
not perpetuated. Allowing AT&T competitive advantage due
to premium access during the transition period can do just that:
It can help perpetuate the advantage of premium access
even after other carriers have equal access.
The FCC Differential
Although the FCC has included a differential in each of
its orders on access charges, the amount and its derivation
have been very different in each case. In the Third
Order, the FCC established a $1.4 billion premium equal to the amount
of interstate CPE and surrogate CPE costs. This figure was
arrived at without any explicit derivation or calculation of
how it would affect the relative price of access between AT&T
and the OCCs. In the Reconsideration the FCC changed its
approach. There it tried to measure the "competitive advan-
tages that flow from the premium interconnection that
AT&T receives compared with the interconnection offered to OCCs."
This time the FCC set the access charge differential by
discounting the Carrier Common Line Charge—the rate element
set to recover a portion of the NTS costs from interstate
usage during a transition period—when applied to OCCs. Based
on recent filings in various state proceedings, this charge
was estimated at 4.6 cents per minute, which, under the Recon-
sideration, would have been discounted by 35 percent, or.
3.1 cents for the OCCs. Since the OCCs would also pay approxi-
ately one-half cent less for certain TS charges, the total
differential would be approximately two cents per minute
in 1984. In contrast, the existing ENFIA differential has
been estimated at from five to eight cents per minute.
In subsequent years the differential was to have narrowed
substantially. The discount on the Carrier Common Line Charge was
to diminish to 23 percent in 1985, to 12 percent from
January 1, 1986, to August 31, 1986, and to none thereafter.
The size of the differential would have narrowed even more
that is suggested by the decrease in the discount, because
the absolute size of the Carrier Common Line Charge was to decrease
from 1984 to 1985 and from 1985 to 1986. In the next few years, therefore, the differential would have fallen
from more than five cents a minute in 1983 to about one cent
a minute in January 1986. The resulting differential would
not have removed the advantages of premium quality access
from AT&T.
While analogous to the value of premium access to AT&T,
rather than the premium that would result from an auction,
the FCC estimate of this value at two cents a minute is erro-
nous and not well supported. The FCC derived its figure by
summing its estimates of projected costs that would be imposed
on AT&T were it to lose premium access. The cost components
that the FCC listed were: the cost of converting rotary
Michael D. Pelcovits and others
dial customers to lone telephone; additional billing costs
due to the lack of automatic number identification and answer
supervision; additional toll switching and other equipment
costs; and the cost of compensating customers for the inferior
grade of service caused by lower quality service arrangements.
There were problems with most of the estimates used
by the FCC; foremost among them was the figure chosen for
the value of being able to offer a superior grade of service
to customers. The FCC assumed that customers could be compen-
sated for an inferior grade of service by offering them 2-5
percent off their MTS bill. Since the FCC chose to use
the middle of its overall cost estimate to derive the differen-
tial, this implies that a differential of 3.5 percent in
MTS rates would compensate customers for the inferior grade
of service.
The two aspects of OCC access that most affect callers
are the poorer quality of the signal and the inconvenience
of punching in more numbers. The FCC valuation of these
aspects of inferior access implies that on an average MTS
call that costs $2.00, a price break of only seven cents
would be sufficient to make the caller indifferent between
the inferior and superior service. The FCC had no basis
for making this estimate, and it is contradicted by the pricing
patterns of the OCCs, who have had to offer substantial
discounts to attract and keep customers. Ascending 85 percent
of the average OCC discount of about 20 percent to factors
other than the need to compensate for inferior access is
simply indefensible.

What is the Proper Differential?
The deficiencies in the FCC calculation illustrate the
pitfalls in trying to measure even the proper theoretical
value to AT&T of premium access. The best approach to
approaching this problem by the technique of directly measuring
the value of premium access to AT&T will not yield a satisfac-
tory answer. Instead, it is preferable to draw from the
actual experience of the carriers under the existing differen-
tial. Prior to January 1, 1984, as noted earlier, the OCCs
paid for access under the ENFIA tariff, while AT&T paid for
the Division of Revenues and Settlements. The difference
in the amount paid by the carriers has not been unambiguou-
s, but a very conservative--that is, low-estimate of the differ-
ential is about 5.5 cents a minute. This provides an obvious
basis for setting the differential for access charges in 1984,
a year in which very little will have changed compared to
1983.
Reestablishing the ENFIA differential has much to recom-
 mend it. First, since it was arrived at through negotiation
among the carriers, both sides had reason to believe they
could live with it. Moreover, it is likely, if anything,
to understate the value of premium access to AT&T. When
it was agreed to, the OCCs had limited bargaining leverage.
They had to have interconnections to be in business, while
AT&T needed an agreement only to cut short some regulatory
proceedings. The likelihood that the ENFIA differential
undervalues AT&T's access is also supported by OCC dissatis-
faction with the outcome. OCCs have not been satisfied with
ENFIA A interconnection at ENFIA A rates and have continued
to press for better types of interconnection. The rate differen-
tial enjoyed by the OCCs was thus insufficient to make
them indifferent between their form of access and the inferior
grade of access utilized by AT&T. Thus, that differential
most likely understates the value of equal access to the
OCCs over the long run.

Summary and Conclusions
The FCC, in explaining and defending its access charge
decisions, has relied in large part on claims of economic
efficiency. While this is a worthy goal, it can be very
difficult to achieve. Analyzing the carrier access charge
proposals of the Third Report as amended by the Recon-
sideration shows how notices that appear in their broad
brush outline to be consistent with economic efficiency,
on closer examination turn out not to yield an economically
efficient outcome.
The FCC's proposal failed to be economically efficient
for three reasons. First, it failed to provide for peak/off-
peak differentials. Such differentials, however, are
needed to make efficient any prices designed to recover traffic
sensitive costs. Second, the FCC's proposal did not even
address the efficiency of the revenue requirement figures
access charges are designed to recover. Prices that recover
more than economic costs are not economically efficient.
Third, the FCC failed to incorporate the proper differential
between what AT&T should pay for superior access and what
the OCCs should pay for their inferior interconnections.
Ironically, the FCC's elaboration of its rationale favoring
a premium does not comport with the way it actually tried
to calculate it. Although the calculation was seriously flawed,
the FCC used the proper concept--the value to AT&T
of premium access. This is not the "auction" opportunity
cost concept the FCC defended.
Examining the FCC's access charge proposals against
the yardstick of economic efficiency, while important in
itsself, points to two more serious issues for the long-run
efficiency of the telecommunications market. The first is
how to deal with uneconomic costs. The second is how to
design efficient mechanisms for the transition from nonmarket
to market outcomes.
The problem of uneconomic costs underlies virtually
all telephone issues facing regulators today. Can economically efficient rates be devised to raise more than the economic costs of telephone service? Should the answer to this be yes, contrary to our belief, would such pricing structures be permitted under existing regulatory laws? These questions do not have easy answers.

Regulators may be helped to meet the challenge posed by uneconomic costs if they can devise appropriate mechanisms for transition from regulatory monopoly to market outcomes. The discussion of opportunity cost as applied to the premium access issue highlights the care that must be taken in applying standard economic concepts to nonmarket situations. If transitions are carried out efficiently, however, the long-run benefits to society should be enormous.

Notes
2. Ibid., at 80.
3. This paper was written before the FCC released its Memorandum Opinion and Order in this docket on February 15, 1984. In that order, the FCC went a long way toward correcting the problem of an insufficient premium addressed here. We believe our discussion remains timely, however, because state commissions still face the same issues. In state access charge proceedings, the problem of appropriate pricing of uneven interconnection is subject to much conflicting testimony.
4. See, for example, Third Report, 427-30.
5. These formulas do change periodically. The Joint Board, composed of both federal and state regulators, currently is considering some changes, but not a wholesale revision.
6. Pricing access on a per line rather than a per minute basis, as the February Order does for DCs, is not inconsistent with peak/off-peak pricing.
7. See, for example, American Telephone and Telegraph Company, Docket No. BC-705, D4 FCC 66 128 (1980).
8. The FCC found evidence of this when it investigated the Bell System procurement processes. See AT&T (Final Decision), 64 FCC 2d 1 (1977).
STATE COMMISSION OPTIONS IN DEVELOPING ACCESS CHARGES

Richard Stanaard

"in the future we will have to evolve problem solvers galore.
for each problem they solve causes ten problems more."
Anonymous

This maxim more than appropriately applies to the current status of the Federal Communications Commission's access charge decision (the Third Report and Order in Docket 73-72 as amended on reconsideration). While the basic rate structure developed by the FCC has solved the problem of charging to discrete pricing structure for a postdissolution, multi-interexchange carrier environment, it has spawned at least ten other problems: (1) how best to preserve universal service; (2) whether separated (Part 67) costs are the appropriate standard on which to establish access charges; (3) whether dual (FCC/state) jurisdiction over access charge costs, prices, and revenues makes sense; (4) which access charge options a state can and should pursue; (5) which level of access charge deaveraging should be permitted; (6) whether jurisdictional arbitrage is a threat to inter/intrastate pricing differentials; (7) whether billing and collection services should be regulated; (8) whether access charges should be peak related; (9) whether access charges should distinguish call setup from holding time costs; and (10) to what extent price elasticity should be factored into access charges.

The purpose of this paper is to discuss state access charge options with reference to many of the problems noted above. Of course, a solution to any one of them might cause ten problems more.

The current press of business with respect to divestiture, implementation of Computer II, and the controversy caused by the FCC's access charge decision has not permitted time for many state regulators to pursue viable intrastate options for access charge pricing, or to develop sound proposals to modify the access charge development and cost allocation procedures contained in Part 69 of the FCC Rules and Regulations for interstate access. However, two things are clear. The first is the overriding state regulatory concern for the preservation of universal service. The second is that the FCC and the telecommunications industry are determined to reduce substantially the amount of nontraffic sensitive carrier costs currently recovered through usage so that toll rates will be "cost based." On the surface, the two conflicting viewpoints do not appear to have any common ground whatsoever, but they may.

The satisfaction of cost-based pricing and the need to find revenue sources to support a lifeline service or high cost pool may have a common ground in the definition of the term "cost-based." Cost can be defined as separated, fully allocated embedded, replacement, reproduction, current, marginal or incremental, both short and long run. It is my belief that the use of long-run incremental costs for determining traffic sensitive carrier access charges will foster economic efficiency, is the proper way to address uneconomic bypass, and at the same time may provide a practical solution to the dilemma of finding revenue support for local subscriber services without causing market distortion.

This latter possibility is contingent upon long-run incremental costs exceeding embedded traffic sensitive carrier access costs—a condition which, contrary to my intuitive inclination, may be supportable by empirical evidence. Furthermore, there is a need to distinguish call setup from call holding time costs, to distinguish originating from terminating costs, and to analyze the elasticity of demand for these services in view of the potential threat of bypass by customers. Private line services require the same analysis, that is, long-run incremental cost analysis and a study of the relative price elasticity of this service as opposed to other offerings. Last, I question the desirability of the current regulatory scheme which provides for divided jurisdiction over interLATA service even though costs are not contingent upon whether the service is inter- or intrastate in nature, and a scheme that bases cost allocations and pricing criteria on a Separations Manual that only addresses embedded costs.
Richard Stambler

The FCC Plan for Access Charges

While state access fee options may appear to be limited because of the overriding influence of the FCC, states are not powerless to initiate action that will affect the direction and policy of the FCC, or to prescribe alternative pricing structures within their respective jurisdictions that will address universal service concerns, establish better cost/pricel relationships, and recognize the industry's concerns about uneconomic bypass. In order to explore these possibilities, it is necessary to look at the FCC access charge objectives and how they were met or compromised in the actual access charges ordered. It is also instructive to look at a recent federal court decision involving pricing standards. I am referring to the decision of the U.S. Court of Appeals for the Seventh Circuit in MCI Communications v. American Tel and Tel Co. The court noted: "This is not an economist's quibble or a theoretical musing; it is a matter of principled analysis and practical reality in the marketplace. Pricing at or above long-run incremental cost in a competitive market is a rational and profitable business practice."

Now let us look at FCC Docket 78-72. The theoretical basis of the Third Report and Order in Docket 78-72 can be found early in the text. At Paragraph 28 the commission stated: "Prices based upon the true cost characteristics of telephone company plant are necessary both to make a decision on whether use of alternative technologies is appropriate and to make a decision on whether to substitute telecommunications for other services" (emphasis added). And at Paragraph 33: "Despite the uncertainty surrounding the precise system size and threat of uneconomic bypass, a delay in the institution of a system of access charges that does not recover most fixed costs through usage rates is not justified" (emphasis added). Thus, it appears that the main underpinnings in the FCC's decision are: Prices should be based on "true costs," uneconomic bypass must be avoided, and recovery of nontraffic sensitive costs in usage rates is not justified.

However, the FCC's approach to these three principles results in three contradictions: (1) Access charges are based on avoided start-up costs instead of true costs (long-run incremental); (2) bypass cannot necessarily be considered uneconomic if it is measured against uneconomic separated costs; and (3) contribution to nontraffic sensitive cost should not be precluded in usage rates if incremental traffic sensitive costs exceed avoided start-up costs, and if pricing decisions properly reflect elasticities of demand (Ramsey prices). Because of these contradictions, the FCC's plan to transform most nontraffic sensitive cost recovery to end-users and to base traffic sensitive access charges on uneconomic separated cost may not properly recognize the interrelated regulatory concerns for universal service or industry concerns related to uneconomic bypass.

State Commission Options

State Access Charge Options

Because of the strong influence of the interstate access charge structure, states should try to bring about improvements in these charges. But state approaches must be logically based to carry sufficient credibility and weight to influence the FCC. States will require information and studies not heretofore performed, will need to recognize the practical constraints imposed upon them by the FCC's decision, and must be willing to recognize that traditional regulatory approaches to the pricing of communications service may no longer be valid in the new environment. I should add here that the incentive to develop better pricing approaches is at least as great for the regulated local telephone company as it is for the state regulator.

Jack and Jill went up the hill to fetch a pail of water.

Jack fell down and broke his crown and Jill came tumbling after.

Jack could have avoided that awful bump by seeking alternative choices like installing some pipe and a great big pump and handing Jill the invoices.

Stacee Holcomb

I believe that five options or steps available to state regulatory agencies concerning charges merit consideration.

Require Long-run Incremental Cost Studies

Most of the economics literature and most telecommunications industry representatives have argued that long-run incremental costs are the proper standard upon which to base telecommunications prices. But regulators, including the FCC, have resisted this approach in favor of fully distributed embedded cost approaches due to difficulties in measuring incremental costs and the need to meet an embedded revenue requirement for the company as a whole. Embedded cost may be adequate for retrospective analyses of how well or poorly a monopoly service performed or an overall basis, but when former monopoly services become competitive, embedded costs have even less relevance. It is here that a long-run incremental analysis is an essential ingredient in establishing proper competitive prices for the future. The question is, what are the implications of pursuing such a policy? Even though it would be correct to use incremental
costs no matter what their level, if incremental costs were below the embedded costs of traffic sensitive carrier access, the state regulator might balk at basing prices on this standard. However, if incremental costs were above the embedded costs, the state regulator would have a legitimate opportunity to establish prices at a level which would serve the dual purpose of promoting economic efficiency as well as funding a lifeline service or high cost pool to address the concerns of universal service.

While incremental traffic sensitive cost studies have yet to be performed for carrier exchange access service, there is some empirical evidence that long-run incremental costs of exchange access may be both above and below the embedded cost to provide exchange access. Essentially, the question boils down to whether the maintenance and capacity cost savings associated with new technology are offset by higher investment costs caused by inflation and higher capital costs to support financing new equipment.

In its most recent rate case presentation,1 New York Telephone Company performed special studies to determine the embedded and incremental costs of local calls. Some of the data are shown in Table 1. Based on the company’s results, it appears that for local calls in the zero to eight-mile range the incremental cost per call is considerably greater than the embedded cost per call. The cost differences noted between residence and business are primarily due to holding time differences. Local calls of greater distance show greater parity between the embedded and the incremental cost. However, the vast majority (83 percent) of all local calls in New York State are in the zero to eight-mile band.

Table 1. New York Telephone Company Local Call Costs

<table>
<thead>
<tr>
<th>Local call mileage band</th>
<th>1985 embedded cost per call</th>
<th>1985 incremental cost per call</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class of service</td>
<td>1985 embedded cost per call</td>
<td>1985 incremental cost per call</td>
</tr>
<tr>
<td>Band A</td>
<td>Res</td>
<td>10.0 (cents)</td>
</tr>
<tr>
<td></td>
<td>Bus</td>
<td>7.9</td>
</tr>
<tr>
<td>Band B</td>
<td>A11</td>
<td>19.2</td>
</tr>
<tr>
<td></td>
<td>A11</td>
<td>19.7 - 23.2</td>
</tr>
<tr>
<td>Band C</td>
<td>A11</td>
<td>29.0</td>
</tr>
<tr>
<td></td>
<td>A11</td>
<td>23.2 - 26.1</td>
</tr>
</tbody>
</table>

New York Telephone Company has also developed embedded and incremental cost studies for toll calls along the same lines as the local calling cost studies.2 Table 2 shows the results for short haul toll calls. This information indicates that the incremental cost of short haul toll is below the embedded revenue requirement for short haul toll. It is generally believed that the cost of toll calls has been on the decline because of substantial efficiencies in the transmission media, such as microwave or satellite in lieu of copper, the use of alternate routing, and the development of larger and more efficient tandem switches. So, while the overall incremental cost of short haul toll may be below the embedded, it is not possible from this analysis to determine which segment of the call link—the local Bell Operating Company (BUC) traffic sensitive portion or the tandem and trunking portion that will be transferred to AT&T—is responsible for the lower unit costs.

Despite the unclear resolution regarding the incremental versus the embedded cost of access from the two studies noted above, there are other sources of information that provide some insight. Two indices used in the communications industry for costing purposes are the Telephone Plant Index (TPI) and the current-to-embedded ratio. The TPI, like the CPI, establishes a base year (1967) value of 100 for the various plant accounts and then measures the nominal change in price over time. The current-to-embedded ratio is a measure of the cost of replacement of plant relative to the average embedded cost. The TPI should be fairly uniform throughout...
the country since the vast majority of plant facilities have
been purchased from Western Electric. Current-to-embedded
ratios may differ contingent upon the average age of a given
plant account, that is, the newer the plant, the less is
the difference between its installed cost and today's cost.

Table 3 displays the TPI and current-to-embedded ratios
for New York Telephone Company. The table shows that the
cost of central office equipment (COE) and outside plant
has increased substantially and is forecast to continue in-
creasing. For example, electronic COE is forecast to increase
in price by 8.7 percent per year between July 1, 1982, and
January 1, 1985. The current-to-embedded ratios for key
plant accounts show the same trend. Again focusing on elec-
tronic COE, by January 1, 1985, the price of plant replacement
will be 43.4 percent greater than the average embedded cost
for this same equipment. Outside plant accounts show even
more dramatic relationships.

The purpose of discussing these analyses is to demonstrate
that, contrary to popular belief, the incremental cost of
traffic sensitive access may be above the embedded cost of
traffic sensitive access. However, the question will not be
fully answered until a true long-run incremental access
cost study is performed. Both the FCC and state regulatory
agencies should require the development of long-run incremental
cost studies for traffic sensitive carrier access and be
prepared to deal with the results accordingly. If the cost of
traffic sensitive carrier access is above embedded, a
case can be made to the FCC with respect to limiting the
amount of phase out of nontraffic sensitive cost from toll
prices, and a more logical approach to determining the con-
tribution level can be developed. If it should turn out that
the incremental cost is below the embedded cost of traffic
sensitive access, state regulatory bodies would have greater
incentive for supporting the FCC's transition plan because
it would provide for a contribution, however unjustified
economically, to nontraffic sensitive costs until 1990. The
industry, however, would be in a position to argue for further
price reductions in carrier access fees to below embedded
cost levels, and uneconomic bypass would loom as an even
larger problem than when it is viewed in relation to embedded
costs.

**Call Setup and Holding Time, and Originating and
Terminating Costs and Elasticities**

Regardless of whether embedded or incremental costs
are used for the aggregate, cost of exchange access, there
are several reasons for disaggregating traffic sensitive
access components in terms of cost and relative elasticity
for call setup, call holding time, and call origination costs
versus call termination costs. The tariffs filed with the

<table>
<thead>
<tr>
<th>Factors applied to individual plant accounts</th>
<th>Telephone plant indices</th>
<th>Current-to-embedded investment ratios</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manual</td>
<td>282.8</td>
<td>201.3</td>
</tr>
<tr>
<td>Panel</td>
<td>278.5</td>
<td>166.7</td>
</tr>
<tr>
<td>Step by step</td>
<td>276.6</td>
<td>276.6</td>
</tr>
<tr>
<td>Crossbar</td>
<td>276.6</td>
<td>276.6</td>
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<tr>
<td>Electronic</td>
<td>180.1</td>
<td>180.1</td>
</tr>
<tr>
<td>Circuit</td>
<td>222.2</td>
<td>222.2</td>
</tr>
<tr>
<td>Pole lines</td>
<td>401.5</td>
<td>401.5</td>
</tr>
<tr>
<td>Conduit</td>
<td>302.5</td>
<td>302.5</td>
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<tr>
<td>Aerial cable</td>
<td>337.4</td>
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<tr>
<td>U.G. cable</td>
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<td>337.4</td>
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<td>Bur cable</td>
<td>337.4</td>
<td>337.4</td>
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<tr>
<td>Subm. or other cable</td>
<td>337.4</td>
<td>337.4</td>
</tr>
<tr>
<td>Aerial wire</td>
<td>359.6</td>
<td>359.6</td>
</tr>
<tr>
<td>Tel. sta. app.</td>
<td>405.3</td>
<td>405.3</td>
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<tr>
<td>Tel. sta. comm.</td>
<td>405.3</td>
<td>405.3</td>
</tr>
</tbody>
</table>
FCC in October 1983 establish traffic sensitive access charge components simply on the basis of minutes of use as opposed to call frequency and minutes of use. There are substantial differences in the cost for setup and the initial minute compared to the cost for each additional minute of holding time.

These differences are summarized in Table 4. The data are from New York Telephone Company forecast embedded cost studies for local calling and short haul toll calling.

A pricing structure for traffic sensitive access that does not distinguish between call setup and call holding time has at least three defects. First, it encourages short holding times on services such as credit checking; just such a problem existed in the MTS rate structure. Under this scenario, the local telephone companies would find themselves short of revenues necessary to cover costs. Second, if the interchange carriers pass this component of cost directly back to their customers, those who generally have lower holding times—residential customers—would pay more than their traffic sensitive access costs. Third, this structure is probably not properly related to the relative elasticities of initial charges and duration charges. To this extent there is a continuing need to price above embedded or above long-run incremental costs to maintain low monthly subscription rates, state strategies should include an analysis of from where that contribution or subsidy can best be derived.

Originating versus terminating traffic pricing and costing should also be an important part of any state analysis of access charge options, especially in view of bypass alternatives. Bypass has two primary forms: point to point, similar to traditional private line services; and utilization by a customer of a private line from his or her premises to an interchange carrier carrier point of presence from which the customer has access to the world. In the first instance, the customer has bypassed the network for both originating and terminating traffic, but only calls between the two points. In the second instance, the customer has bypassed the originating end of the local switched access facilities, but will terminate the call in another exchange requiring the use of local telephone company access facilities. However, this scenario suggests that terminating traffic may be less susceptible to bypass than originating traffic, since it is not possible to install a private line to every desired distant and premises. Put another way, terminating access is probably less price elastic than originating access. With this in mind, it may be possible to design prices which address the bypass issue on the front end, while attempting to derive contribution from the terminal end points to be emphasized is that these pricing decisions cannot be reached until studies of the relative elasticities of these types of access are performed.
Line Facilities. The FCC's decision to apply this surcharge may not be at all improper, however, in view of the relationship of incremental costs to embedded costs.

The states' strategy with respect to private line services should be to require the development of incremental cost studies for private line loop and interoffice mileage facilities in recognition of the higher incremental costs and the contribution that could be derived from incremental cost pricing. The FCC's $25.00 charge produces between $1 billion and $1.2 billion from interstate circuits. About $.6 to $.8 billion will be realized from intrastate circuits if the states apply the same rate. States should be prepared to take similar actions on an intrastate basis and, with cost studies in hand, be prepared to address future FCC proposals which may phase out the surcharge and return to embedded costs, a move that may be unwise because the incremental costs for the provision of this service are in excess of the embedded.

Eliminate Separations for Apportioning Inter- and Intrastate Costs and for Setting Rates

The time has come to question seriously from a state perspective whether the jurisdictional separations process continues to make sense. The original intention to apportion nontraffic sensitive costs to the interstate jurisdiction for recovery through traffic sensitive prices has been turned upside down by the FCC's access charge decision, and properly so. In addition, several ratemaking anomalies have been created. For example, the very same nontraffic sensitive plant which is priced well below cost on a residual basis within state jurisdictions will be priced to produce a 12.75% rate of return on an intrastate basis. The very same access call, whether used to access inter- or intrastate interLATA carrier facilities, has the exact same cost in the real world. However, because of the Gap Separations Procedures, Part 67 costs of an access call may be different between inter- and intrastate jurisdictions. The probability that a customer will receive three flat rate charges—two for local access and two for toll access—is a bewildering situation when the same line is used by the customer for access to all.

Last, the continued use of Part 67 requires policies and allocation procedures to develop traffic sensitive carrier access fees severely limits the flexibility of state and federal regulators to establish prices more appropriately reflecting long-run incremental costs and/or market conditions.

The best way to consider all these factors is to put aside the separations approach, recognize the new telecommunications environment, and alter the current jurisdictional structure. The FCC should regulate all interLATA services (unless deregulation is appropriate). Similarly, states should regulate exchange access for all calls-within board federal

State Commission Options

Because of individual state resource limitations, efforts to develop immediate and comprehensive alternatives may simply be impossible. While the search continues for alternative costing and pricing policies, mirroring the FCC access charges on the state level may be the only feasible option. From an industry point of view, it eases the administrative burdens and eliminates questions of jurisdictional arbitrage. From a state regulatory point of view, it comes close to maintaining the status quo—at least in year one. But, from either point of view, there are the deficiencies which I have discussed that need to be addressed.

If states seek either greater independence from the FCC decision or changes in it that will refine or redirect the prices charged to interexchange carriers for local access, well-documented evidence will be required. Not only are incremental cost studies important, but also the perceived threats to universal service from price increases or from bypass must be documented. It is here that states have a major responsibility and a major interest in the development of information that correlates the effect of FCC access charges on universal service in such demographic categories as income, age, and urban versus rural sectors of our population. States and the local telephone companies they regulate also have a major interest in documenting the effects of bypass on operations and income.

Conclusions

I am not ready to conclude that the FCC's decision is the answer for the future, but it is a good start. Nor am I ready to conclude that state concerns for universal service are unfounded, but they are probably overstated. I am ready
to conclude that too little is known to proceed much farther. Options and alternatives have not been exhausted. Many have not even been explored. Until they are, the verbal bottle of "ifs," "maybes," and could be's will serve neither the regulator's interest, the industry's interest, or the communications user's interests.

While I would like to state with certainty whether the long-run incremental cost of interexchange carrier access to the local network is above or below embedded cost, I cannot. It is, however, a question that requires an answer. I am willing to conclude that incremental private line costs are above embedded levels, and that rate structure changes to support a distinction between setup and holding time for interexchange carrier access charges are cost justified and a logical refinement to the FCC's plan. Last, the continued divided jurisdiction over interLATA services and the use of jurisdictional separations make little sense.

Notes

1. See Testimony of Robert Anderson, NYPSC Case 28264 and 28906.
2. See Testimony of Mills N. Ripley, NYPSC Case 28264.
3. Data are not available for incremental cost but are expected to show the same pattern.


Brian P. Sullivan

This paper attempts to deal with a problem in terms both abstract and real. The problem can be defined as follows. Imagine an industry that involves the transport and distribution of a product or service. Further imagine that the transport between major hubs or nodes is either competitive or potentially competitive. Once the product arrives at a node, distribution to individual end-users within that node takes place over facilities provided by a monopoly. It should be clear that if the monopoly distributor chose to offer either lower rates to a single internode transporter or the same rates for preferential service to a single internode transporter, then competition in the internode transport industry could be harmed if the same internode transporter consistently received "favored," "unequal," or "better than equal" access to the local distribution system. In such a situation, if public policy dictates that internode competition is to be encouraged, but at the same time local distribution monopolies are to be protected, then it is a nontrivial question as to who should pay for equal access to the local distribution system. This paper will explore several issues.

Note: The opinions expressed here do not necessarily represent those of the Southern New England Telephone Company or its management. The author wishes to thank William Mewhiss for substantial input to the third section; any errors are those of the author.
related to this topic. Some include: Who benefits from equal access if equal access is the only class of access offered? Who benefits when equal access is an option along with tariffed grades of unequal access? The organization of this paper is as follows. First, the abstract problem is characterized for a number of industries, including the intercity telecommunications industry. Second, the history of relevant policy changes in telecommunications is briefly reviewed so that equal access can be distinguished from other major policy changes which have confronted this industry. Third, implications of equal access are explored through a series of verbal models. These will assume away related policy changes so that the implications of equal access can be highlighted. Finally, equal access will be reviewed as one among a series of access options.

Applicability to the Real World

The stylized industry described in the opening paragraph is characteristic of several others. For example, airlines compete in hauling passengers and freight between city pairs, but the landing facilities within a city are generally owned by an airport authority or other governmental entity which runs the airport as a natural monopoly. In only a few instances do large cities have two or more airports where intercity carriers can compete on the basis of originating or terminating facilities.

Travellers are familiar with landing at Washington National Airport versus Dulles in effect receive unequal access because of the greater ground transportation requirements. Indeed, access is so unequal that landing rights at National Airport are restricted by nonprice rationing schemes, and the government has built a special access area at Dulles for limited traffic.

A more blatant case of discretionary unequal access occurred on the air route between Dallas and Houston. With the completion of the Dallas-Fort Worth and Houston Intercontinental fields, all airlines agreed to forgo their landing rights at Hobby Field (Houston) and Love Field (Dallas). A niche competitor was forced to provide only intrastate service and secured landing rights from the Texas Aeronautical Commission for a service from Hobby to Love. This eliminated approximately one hour from the downtown-to-downtown travel time of any competitor. The unequal access together with aggressive price cutting enabled this competitor to garner a substantial share of the Texas intrastate market by the mid-1970s.

The exploration for and production of natural gas is generally regarded as a competitive industry. The transport of natural gas is influenced, however, by the economics of pipeline transport. For obvious reasons, gas pipelines tend to be natural monopolies. Price controls on field natural gas and retransmission regulation of the pipelines have created what amounts to unequal access to the pipeline transport system among natural gas producers. This unequal access has become manifest in the form of take-or-pay contracts and, more recently, in the form of defaults on those contracts.

Generation, transmission, and distribution of electric power provide the last example of a potential equal access application. While all these activities are currently subject to historical retransmission regulation, it is at least technologically possible that generation of electric power could be deregulated. The possibilities related to access in this case could be fascinating. For example, opponents of nuclear power could insist that this technology pay a premium access to local distribution to compensate ratepayers for psychological harm. Gogenerators likewise could be given subsidized access rates to reward them for their contributions to society.

Mechanics of Access to the Local Loop

This section describes how local access and distribution are provided to intercity carriers of long distance service. In particular, the access enjoyed by the Bell-Independent partnership is described in nontechnical terms. Those familiar with telephony can omit this section and retain continuity of the paper.

Telephone calls are initiated when the calling party lifts the receiver or goes "off hook." An electrical connection is then made in the telephone set and through a pair of wires running from the subscriber's premises to his local (or serving) central office. The electrical connection causes the switch to seize an idle trunk, which returns the familiar dial tone to the subscriber. After the subscriber dials, the switching equipment routes the call based on the numbers dialed. As of 1983, the completion of the call differs depending upon whether AT&T is used as the intercity carrier.

The AT&T case can be described first, since it is so familiar. Prior to the AT&T divestiture, both the Bell Operating Companies, such as Chesapeake and Potomac or Southern New England Telephone, and the Independents, such as Continental or United Telephone, were "partners" with the long lines division of AT&T in completing interstate calls. The local companies were compensated through separations and settlements procedures.

From World War II until the 1970s, long distance calling was the exclusive province of the telephone company. Because of the Division of Revenues process and the monopoly franchise granted to local telephone companies, the Bell-Independent
The **ratepayer** is charged for the amount of the rate, and the rate is then adjusted to reflect the cost of providing the service.

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in waves of regulatory and judicial proceedings.

Despite legal and regulatory uncertainties, increasing numbers of interconnect suppliers introduced a wide variety of terminal products to the business market. Responding to the requests of these vendors, a series of FCC decisions liberalized the terms of interconnection. Most notable among these actions was the 1976 FCC registration decision which allowed subscribers to interconnect without the need of telephone company provided interface equipment designed to protect the network. The prevailing FCC philosophy continued to permit customers to take actions which were seen as privately beneficial but which did not harm the public network. The protests of the carriers about loss of end-to-end service responsibility, potential harm to the network, and loss of profits used to subsidize basic network service fell on increasingly deaf ears.

As important as the issue of terminal equipment interconnection seemed, it was overshadowed by the FCC's 1969 decision to allow Microwave Communications Inc. (MCI) to construct a microwave transmission system to provide point-to-point private line service between Chicago and St. Louis on a common carrier basis. Although private microwave systems used by individual firms had been permitted since 1959, the expansion of competitive common carrier microwave systems as an alternative to telephone company monopoly services began the process of opening the entire intercity transmission market to competition.

The significance of this decision was not lost on the Bell System. While approximately one-fifth of Bell's annual revenue comes from the terminal equipment market, more than one-half of total revenue is currently derived from intercity network services. In order to compete on the high density routes where economies of scale made the routes most profitable, the pricing scheme of the Bell-Independent partnership which provided uniform per mile rates based on nationwide average costs allowed carriers who could elect to serve only high density routes to undercut the prices of established carriers and still earn handsome profits, a practice derided as "creepskimming" by the established carriers.

Following the MCI decision, the FCC received a large number of applications to open microwave facilities to provide specialized common carrier services. In order to establish policies and procedures for this area, the FCC opened its Specialized Common Carrier Services docket. In its first report in this docket, the FCC took the position that it was authorizing specialized common carriers only because it was satisfied that the new companies would offer innovative services not presently provided by telephone companies and which therefore would not significantly diminish the revenues of existing companies.

However, in a series of decisions culminating in Expernet, in 1977, the Federal courts forced the FCC to abandon this narrow definition of specialized common carriers. Expernet reversed a 1975 FCC decision which effectively precluded MCI and others from providing regular switched long distance calls over their own microwave networks. The telephone companies were ordered to carry the "final mile" of Expernet calls over their local switching and distribution networks. This decision effectively allowed the specialized carriers to compete for all toll calling over any route of their choosing. The common carrier intercity network was now completely open to competition and with it the more than $30 billion in intercity switched service revenues.

In 1972, the FCC in Dunsin allowed nontelephone company applicants to provide transmission services through satellites and opened another technological frontier to competition. The FCC's Computer Inquiry II and Resale and Sharing decisions as well as the terms of the consent decree settling a civil antitrust suit brought by the U.S. Department of Justice against AT&T in 1974 made it clear that regulation would no longer be supplemented by competition; rather, regulation would be replaced by free market forces to the maximum degree possible.

In April 1980, in its final Order in the Second Computer Inquiry, the FCC ordered the deregulation of newly provided terminal equipment and enhanced transmission services effective January 1, 1983. In order to deal with concerns about cross-subsidy between monopoly and competitive parts of AT&T's business, the FCC ordered that AT&T participate in the competitive markets only through a fully separated subsidiary.

In its 1981 Resale and Sharing decision, the FCC permitted unregulated resale and sharing of network services. Under this decision, companies can buy long distance services at high user discount rates (for example, MATS) and resell them to residential consumers or businesses. Resale and sharing effectively allow middlemen to arbitrage away any rate difference among substitute services. If such rate differences are not cost based, there is potential for significant erosion of common carrier revenues.

On January 8, 1982, AT&T and the U.S. Department of Justice announced settlement of the antitrust suit filed in 1974. An earlier suit filed by the Department of Justice against AT&T in 1949 culminated in a consent decree signed in 1956. The newly announced settlement vacated the 1956 decree and replaced it with a restructured Bell System. AT&T and the Department of Justice agreed to spin off local telephone service as a separate business to be provided by existing BRSs. These are to retain their individual identity but are to be owned by seven regional holding companies. Stock in the holding companies is to be flown through to

Equal Access
AT&T shareholders. These new companies are excluded, by the consent decree, from the provision of terminal equipment installed prior to the divestiture. The divested BOCs are also excluded from owning facilities for interstate long-distance transmission services. Once divested, they can become do have entrants into terminal markets. Yellow Pages advertising remains with the divested BOCs.

In return, AT&T, which would be a single national provider of competitive terminal products and transmission services, is freed from the 1956 consent decree, which restricted it to regulated communications service. This separation of local monopoly services from the competitive markets was the most dramatic step to date in completing the opening of two-thirds of the telephone business to competition.

The Modification of Final Judgment (MFJ) which ended the Department of Justice suit against AT&T contains the following provision with respect to equal access: "Subject to Appendix B, each BOC shall provide to all interexchange carriers and information service providers exchange access, information access, and exchange services for such access on an unbundled, like-quality, and price to that provided to AT&T and its affiliates."

Upon divestiture no BOC shall provide interexchange telecommunications or information services. The MFJ further requires that the divested BOCs begin to offer "non-discriminatory access" by September 1, 1984, and to have such access available in each local office by September 1, 1986. Of particular importance to the remainder of this paper is the requirement that "each tariff for exchange access shall be filed on an unbundled basis specifying each type of service, element by element, and no tariff shall require an interexchange carrier to pay for types of exchange access that it does not utilize. The charges for each type of exchange access shall be cost justified and any differences in charges to carriers shall be cost justified on the basis of differences in services provided."

Running concurrently with the Department of Justice antitrust suit was the FCC proceeding in the Matter of MTS and WATS Market Access, 1980 First Report and Order. In the introductory paragraph to its Third Report and Order, the FCC stated: "When this commission initiated this proceeding to determine an optimal market structure for the MTS-WATS market, we concluded that it would also be necessary to prescribe the compensation that exchange carriers should receive for the origination or termination of all interstate and international services of all carriers."

The settlement of the antitrust case forced the FCC to modify some of its terms: Although the tentative plan we described in 1980 would have limited the definition of access to facilities that are used in common

by exchange and interchange services, we have expanded the definition of access to correspond with the Modified Final Judgment in the AT&T antitrust case. The FCC ordered that each BOC file on its own, or through the Exchange Carrier Association (ECA), a set of access tariffs by October 3, 1983.

The amount of resources involved is enormous. The FCC estimated that by 1984 the revenue requirement associated with nontraffic sensitive plant would be $8.5 billion, while traffic sensitive plant had an associated revenue requirement of between $2.5 and $3 billion. Under the division of revenue mechanism, these costs are recovered entirely on a usage sensitive basis, with the contribution paid by the Bell-Independent partnerships (on a per minute of use basis) being greater than that of the COCs due to the 45 percent discount on nontraffic sensitive rates provided under INI.

The FCC plan would have collected these nontraffic sensitive costs directly from end-users in the hopes that rates for MTS-WATS and similar services would be driven (down) toward cost by the forces of competition. According to the FCC, the welfare gain due to stimulated usage of intercity calling was on the order of $1.5 to $1.7 billion per year.

Implications: Costs versus Benefits

As was noted in the previous section, the FCC had been considering access compensation independently of the Department of Justice antitrust suit. It will be useful to consider what equal access would have done in the absence of divestiture. Consider, first, the case of mandatory equal access. In this case, one can imagine that both AT&T and the COCs have equal access (equal in price, type, and quality) to the local network. The only basis for competition becomes efficiencies in intercity transport or service differentiation such as free trials, liberal refund policies, and so forth.

If, as is commonly assumed, there are economies of scale in intercity transport, then equal access would benefit the carrier with the largest market share. To overcome such a cost advantage, other carriers would have to differentiate themselves in terms of service, transmission quality, blocking, or ubiquity. Comments of parties in the access charge docket support the notion that aside from AT&T there is little effective demand for equal access. Consider the following verbatim citations from Appendix C of the access charge order.

AT&T endorses the Commission's interim plan as a necessary first step toward the goal of non-discriminatory access charges (Third Report and Order, Appendix C, paragraph 1).
MC1 contends that the reasons cited by the FCC for immediate action are not compelling, and that an extensive evidentiary hearing is required to clarify numerous issues before any access charge plan is adopted (paragraph 57).

SBS shares MC1's general assessment of the FCC's plan, believing that there has been no demonstration of urgent need for action to relieve discriminatory circumstances, and that the plan outlined by the FCC would itself be discriminatory by imposing equal charges for unequal service (paragraph 60). 

SBC's position is very similar to that of MC1 and SBS (paragraph 73). 

The OCCs apparently object to paying, through access charges, part of the cost of subsidizing local telephone service. This can be a legitimate argument for two reasons. First, without divestiture, AT&T would be providing about 80 percent of the U.S. population with local service. Logically, any subsidy paid to AT&T's customers is paid (at least in part) to AT&T and its shareholders. The second reason is economic efficiency. Demand elasticities for intercity telephone service tend to be far greater than those for local access and usage. To the extent rates deviate from marginal cost, Ramsey pricing would suggest far higher rates for local service.

The second concern of the OCCs is that the BOCs cannot physically provide all OCCs with access of the same quality as that provided to AT&T. The OCCs dealt with this problem extensively. 

The commission has used the rationale that premium access could, in theory, be auctioned off and its value determined. Since physical transfer of this access cannot be accomplished, the FCC estimated its value to be $2.2 billion per year.

The divestiture of the BOCs from AT&T removes the concern of forcing the OCCs to subsidize a competitor. The concern over economic efficiency is less easily handled. To the extent that a positive externality flows from exchange access to all users of intercity telecommunications, pricing both end-user access and intercity usage at marginal cost does not achieve economic efficiency. The premium access charge levied on AT&T amounts to changing the existing OCC E911 discount from 45 percent to 35 percent. 

The premium access phases out in three years and is reduced to zero after September 1, 1984.

The comments made by the parties indicate that there is very little market for true equal access. Some of these comments are noted below.

AT&T finds the premium charge objectionable but believes that consideration of the USF (Universal Service Fund) should take place in Docket 80-286 (page 9).

ATTIX (AT&T Interexchange) believes that full and fair competition should begin. A penalty on ATTIX that goes beyond the current premium has no place in a competitive marketplace (page 10).

Brophy notes that the net result of the rules is an increase in OCC charges and a decrease in AT&T charges. The gap is reduced from 80 percent to 25 percent with no change in access quality (page 19).

MC1 believes that the Commission should focus only on unwarranted parts of the order. MC1 submits that the Commission's greatest concern should be the marked transient increase in OCC charges (page 22).

SBS supports the basic thrust of the action but believes that the transition toward equal access requires re-examination (page 35).

It has become distressingly apparent to SPRE that the access charge plan, as adopted, will not promote the objectives of competition, reasonable transition, narrowly focused subsidy, and non-discrimination. Until such time as equal exchange access is generally available, an appropriate price differential is needed. The access charge plan would eliminate or vastly reduce the past differential. This differential would fall from 57 percent to 19 percent (page 37).

When equal access is the only offering, the marketplace participants do not place great value on this access. The case of unequal as well as equal access can now be considered. This is the case envisioned in the NII's use of the term "unbundled services." Neither the NII nor the FCC access charge order requires that interexchange carriers (1) be limited to only one type of access or (2) pay equal amounts on a per line basis for access to the local network when access is inferior to that afforded AT&T. Under access tariffs filed by the Exchange
Carrier Association on October 3, 1983, several grades of access are offered. For example, feature group B offers a series of offerings approximately equivalent to the ENFIA-A offering. The ENFIA interconnections must be obtained through the OCCs. Feature group B offers an option to acquire ENFIA-C interconnection, which is the option sought by Satellite Business Systems. Feature group D is an offering reserved primarily for AT&T and carries with it the liability of paying a premium access charge of $2.2 billion per year. Feature group D is the equal access offering. Beginning in mid-1984, some central offices will offer feature group D to any carrier wishing to provide service. Virtually all BOCC central offices must offer feature group B by September 1986. 71 In addition to these feature groups, the OCCs will offer a variety of digital data access options as well as special assembly access connections.

The combined effect of the NJP and the access charge order is to create a situation in which the BOCCs must undertake substantial effort to reengineer and make extensive software adaptations to existing central office facilities. In a legal as well as economic sense, it is unclear as to who (the BOCCs, AT&T, or AT&T and the OCCs) will pay the cost of providing equal access. What is clear is that access equal in type, quality, and price to that afforded AT&T will not be provided, but only as an option. By compelling the BOCCs to offer access on a service-by-service basis, it is possible that no carrier, including AT&T, would buy equal access (feature group D). To the extent that the OCCs have built their business by attracting customers who are price sensitive but relatively indifferent to quality and convenience, equal access could eliminate the existing competition of these carriers.

The problem outlined in the beginning of this paper is now presented in detail. Public policy has decreed that the BOCCs provide equal access at rates fixed by the FCC. However, the cost of equal access has two elements, the private costs paid to reengineer and readapt central offices, and the social costs (or benefits) measured in an enhanced choice of service providers and a redistribution of wealth among customers. The beneficiaries of equal access, however, the social costs involved in the access charge is the cost of access with long distance calling, are not obvious.

The private costs of providing equal access appear to be large in absolute dollar amounts but insignificant when compared to the size of the BOCCs. 76 There are cost differences among the BOCCs based on characteristics such as age of plant and population density of service areas. In addition, the OCCs were willing to agree to a modified equal access schedule as part of the price it paid to acquire Southern Pacific Communications Corporation.

Resistance by the OCCs to current FCC rules about access charges indicates that the social costs of equal access have received little attention. Nevertheless, these costs may be substantial. Should the marketing strategies of AT&T and the OCCs evolve in such a way that AT&T migrates to feature group D access while the OCCs remain with what looks like ENFIA-A connection, then little will have been done to enhance the development of competition beyond what existed prior to AT&T divestiture. The deadweight loss to society in this case would be approximated by the private cost of equal access, since resources will have been expended to produce a product no one will take. 75

The likelihood of this scenario is reduced by the fact that the private cost of ENFIA-A interconnection to the BOCCs is almost as large as the cost of existing AT&T interconnection. Non-discriminatory rate making, therefore, would require any OCC selecting ENFIA-A interconnection (despite its service inferiority) to pay rates to BOCCs almost equal to those paid by AT&T (except for premium access, which phases to zero in three years). In this event, the OCCs cannot maintain their price differential. Moreover, OCCs with access of the ENFIA-A type would continue to offer service lower in quality and convenience than that offered by a feature group D carrier. In this case, carriers would migrate to feature group D access to be at a price-performance point that is competitive with other vendors, including AT&T.

Local access costs are a significant portion of the total cash outlay faced by OCCs. For an OCC with heavy investments in its own intercity transport facilities, with 15 to 20 percent of total revenues are paid out to the BOCCs under the ENFIA-A rates, which allow a 45 percent from the rates imputed to the Bell-Independent partnership. OCCs who rebate the facilities of others indirectly pay access rates since the rates charged by the facilities carrier to the reseller should include access charges to be compensatory. For an OCC owning most of its own facilities, the prospect of a doubling in its access charges to one-third or more of total revenues can be debilitating. This would greatly reduce or eliminate the price advantage of the OCC. If there are large economies of scale in intercity transport, the price advantage could be eliminated or even reversed. Such a development would destroy effective competition in the intercity marketplace. The deadweight loss due to such an outcome would not only be the private costs of equal access, but also the foregone benefits that intercity competition allegedly brings.

Summary and Implications

The distinctive competence of the OCCs to date has been their ability to price substantially below the Bell-Independent partnership. Prior to divestiture, attempts to achieve economic efficiency by attempting to price both local access
and intercity usage on a cost basis founndered because the Bell-independent service partnership controlled local access. Therefore, with superior interconnection, parity of intercity printings would substantially weaken if not eliminate competition in the intercity market.³⁵

As presently constituted, equal access does not appear to enhance competition. Either the ICCs stick with their current access arrangements at current relative rates, or all carriers obtain similar access and strive for their competitive advantage in areas other than type, quality, and cost of access.

The behavior of the ICGs and their public statements before the FCC suggest that there is little effective demand for access that is equal in type, quality, and price. While truly equal access would, in all likelihood, serve to be quite damaging to the state of competition in the intercity communications market, divestiture and nondiscrimination require that access be provided on a basis and under terms which treat all carriers equally, and provided at rates which cover all economic costs.

A final option for the AT&T and ATC would be to integrate backward through local access that bypasses the existing Bell local networks. Indeed, access tariffs that require intercity carriers to support local nontraffic sensitive plant through the payment of traffic sensitive rates will only heighten the incentive for such backward integration. Even under economically correct tariffs that properly separate and charge for costs according to traffic sensitivity, the bypass incentive will remain, with one-third or more of their revenues going for local access, intercity carriers will need to differentiate their services by some means, with local access accounting for such a large fraction of the cost of goods sold, the new contribution of the equal access requirements of the MFJ may be to move local access and local telephone service closer to competition and away from historical resale regulation.

Two avenues appear to lie ahead. First, the FCC or other policy makers need to examine the optimal market structure for MTS-WATS and similar services.¹⁸ The access charge order appears to assume that the economically efficient market structure is competitive, and, therefore, local access need be secured under nondiscriminatory tariffs.¹⁷ However, a true externality flows from local access to interexchange services and local access is a natural monopoly, then economic efficiency is best served by an implicit tax on interexchange services to support local access. This last point contains an assumption regarding the economically efficient market structure of local access. The second avenue for policy makers is to examine the market structure of local access in light of the difficulties created by a resale regulated local distribution industry and a competitively structured

1. A second analogy between natural gas pipeline transmission and local telephone network distribution also exists. A local distribution company generally buys gas from an interstate carrier and distributes it to end-users at a markup based on ratebase regulation. Interstate pipelines have found that they can bypass the local utility and get gas directly to large industrial users, who thus avoid paying discriminatory local usage rates. Intersity telephone companies will soon have the incentive to bypass the local exchange companies, especially when serving large users, for as long as local access costs are collected as a surcharge on minutes of use. For clarity of exposition, this paper assumes that the local exchange companies are natural monopolies. It is, of course, recognized that typical bypass is a real threat facing local telephone companies.

2. I am grateful to James Plummer of O.E.D. Research for these insights into deregulation of electric power generation. The prospect of litigation of preferred access in this industry must give delight to lawyers and economists as they unwind from the AT&T divestiture.

3. The assumption is that the customer has dialed a call to an area code (number planning area) different from the area code in which the subscriber's telephone is located.

4. A more recent tariff, ENFIA-C, gives the OCCs access through the tandem switch serving a metropolitan area. The access into the tandem then provides access to each of the subending end offices. As of 1983, most OCCs relied on ENFIA-C connections, even in areas where ENFIA-E was available.

5. Actually, they must use Touchtone lines.


7. FCC Above 350 Decision (27 FCC 359 (1959)).

8. FCC Carterphone Decision (13 FCC 2d 420 (1968)).

9. The effect of this decision was to expand the degree of competition in the manufacture of terminal equipment.
as well. To the extent a telephone company would offer the terminal gear manufactured by its own affiliated entity, Carterphone indirectly subject[ed] manufacturers (such as Western Electric or Automatic Electric) to increased competitive pressure as well.

12. FCC Specialized Common Carrier Decision (29 FCC 2d 870 (1971))
14. FCC DQ/AT Decision (35 FCC 2d 844 (1972)).
15. FCC Docket 20828, Second Computer Inquiry, 77 FCC 2d 384 (1980); and FCC Docket 80-54, Rezise and Sharing of WATS/MTS.
17. FCC Docket 80-54, Rezise and Sharing of WATS/MTS.
18. MFJ, Section II, page 3, paragraph A. The reference to "exchange services" in the MFJ is broader than it might appear at first. Exchanges on local access transport areas (LATA's) are created. Some LATA's are quite large, encompassing an entire state (as in Maine). The more heavily populated states are divided into two or more LATAs. There are 158 LATAs throughout the United States.
19. MFJ, Section II, page 4, paragraph D.
22. Ibid., page 4, paragraph 6.
23. Ibid., page 10, paragraph 25.
24. Ibid., pp. 36-37, paragraph 112 and footnote 39. The FCC was also concerned about the risk of bypass of local

Equal Access

26. I use the economist's definition, willingness and ability to pay, as opposed to claims of equal access for my competitors, premium access for AT&T, and unique access for me.
28. SPC: Southern Pacific Communications.
29. See Docket No. 77-72, Third Report and Order, paragraphs 351-58. Also see Memorandum Opinion and Order, Docket No. 70-72, adopted July 27, 1983, paragraphs 92-128.
30. Memorandum Opinion and Order, paragraph 127.
31. Ibid., Appendix B passing.
32. Chairman of the Board, General Telephone and Electronics, which owns Southern Pacific Communications Company (SPC).
33. Details of these packages can be found in Section 6 of the access charge tariffs. Originally designed to be effective on January 1, 1984, the FCC had suspended the effective date for 90 days. In 1983, General Telephone and Electronics acquired Southern Pacific Communications. In doing so, GTE signed a consent decree with the U.S. Department of Justice whereby GTE committed to equal access by September 1980 from those territories in which GTE is the local carrier. Also, after September 1988, AT&T does not pay a premium access.
34. As noted earlier, GTE will also provide equal access by 1988. This leaves a situation in which the Independents (serving about 15 percent of local telephone subscribers) are not yet committed to an equal access schedule. The FCC has issued a notice of inquiry to examine this issue.
36. This paper deals only with equal access. Divestiture requires that the BOCs earn a fair rate of return from providing local end-user access. Large BOC rate filings together with the FCC's "Pure 2" plan to shift in a gradual manner all nontraffic sensitive revenue requirements to end-users in the form of a flat rate monthly per line charge means a substantial increase in local rates. Substantial welfare gains and losses will result but are beyond the scope of this paper. Equal access could have been implemented without divestiture, either along FCC lines or by forcing the BOCs to participate in the division of revenues. The latter choice would make a cartel out of AT&T and the BOCs.

37. The gains by pricing local access and interexchange usage on a consistent cost basis are large. In theory, the public could achieve these gains by continued monopoly regulation of AT&T. Neither equal access nor divestiture is necessary to obtain these gains.


Comments

William E. Taylor

I am in the potentially embarrassing position of commenting on two papers with which I am in broad agreement. The first, by Kenneth Gordon and John Haring, marshals compelling evidence to show that customer access charges, at their likely levels, would have no significant effect on the proportion of households subscribing to telephone service. The second paper, by Richard Stannard, points out that embedded costs may differ from incremental costs and that state regulators may therefore have some new options available to mitigate the effects of federal end-user charges on universal service. Of course, if the first paper is correct, the second is unnecessary. However, some additional qualifications should be made to Gordon and Haring's conclusions, and there are other difficulties facing state commissions regarding access charges which Stannard did not address.

An important question is whether recent FCC telephone rate reforms are a threat to universal service. The answer is clearly no, but it is also abundantly clear they are a threat to something. Gordon and Haring make the important point that the issue is probably income distribution or fairness rather than concern for universal service. Additional support for this view comes from the observation that one...
of the most vociferous groups opposing access charges is the elderly. A group characterized by high telephone penetration, relatively low price elasticities of demand for service, and fixed incomes.

An equally valid reason, however, is that negligible effects are still very large. A one percent change in penetration involves approximately 800,000 households or roughly the entire constituency of four members of the House of Representatives. Of these 800,000 households, a disproportionately large number (28 percent) has incomes below the poverty level, but a disproportionately small number (16 percent) has heads over age 65. The conclusion that negligible changes in penetration have large consequences which may be perceived as unfair seems inescapable.

A second important point Gordon and Haring make is that subsidies should be directed at customer groups which would otherwise have the network. Nothing in terms of promoting universal service is to be gained by subsidizing nonfinancial households. This, however, ignores the above concern with the importance of perceived fairness. This standard for subsidies in simply a standard of the cheapest method to direct subsidies to maintain a given level of subscriber demand. A subsidy to the elderly, for example, would be expensive (they constitute approximately 20 percent of households) and would have little effect on the proportion of households subscribing to telephone service, but it might be perceived as necessary for the sake of fairness.

A final subphasis on Gordon and Haring's analysis concerns their criticisms of Perl's study, in particular, the claim that Perl's price elasticity estimates are biased upward due to the omission of equipment and long distance service prices as explanatory variables in the model. If, however, those prices are largely constant across the United States at any given time, there is no reason to think Perl's price elasticity estimates to be biased. The effects of long distance and equipment prices are likely to differ markedly across states.

For options available to state commissions in developing access charges, Stannard lists five which can be boiled down to three: (1) move toward pricing on an incremental cost basis; (2) require the jurisdictional separation of the effects of access charges on the state level; (3) impose the cost of access charges on the state level. If access is priced at a higher rate than incremental costs, it increases the potential problem of flowing subsidies between services.

I fully agree with the main point: that one cannot make economically sensible judgments when the yardstick is embedded, fully distributed costs. If nothing else, movement toward incremental costs redistributes income from accountants to economists. Stannard goes on to discuss the possibility that incremental costs exceed embedded costs for carrier access, so that incremental cost-based pricing would generate a surplus that could be used to subsidize access. It is a potentially good idea, since Ramsey pricing would require that the relatively more price-elastic service (carrier access) be priced closer to incremental cost than the less price-elastic service (residential access). The cost relationship, however, is unsettled at best. The New York Telephone cost studies cited give different results for local and short haul toll. Moreover, both high incremental costs for installing new technology may not fully account for quality change in the price index. Thus, what appears as high incremental cost in switching might only reflect increased speed, capacity, or features.

The jurisdictional realignment is not a novel idea, nor does it solve the basic problem. Ultimately, it is the forces of competition which require that NTS costs be recovered from the carriers on a flat rate basis, not political or jurisdictional forces.

Finally, distinguishing set-up from holding time costs and originating from terminating costs is a sensible suggestion. However, it is ironic that the study cited to show how these costs differ uses embedded and not incremental costs.

Like Sherlock Holmes' dog that failed to bark, an interesting feature of the paper was a problem facing state regulators that was not addressed. Stannard suggests that mirrorine interstate carrier access charges on the state level may not be the only feasible option. I am concerned that this option may not always be feasible. I concur with his argument that arbitrage will ultimately force parity between interstate and intrastate carrier access charges; however, both incremental and embedded costs of access are likely to differ markedly across states. The pooled NBER common line charge may either over- or underrecover intrastate NTS costs, and if the company is in the NECA traffic sensitive pool, its traffic sensitive rates may either over- or under- recover embedded or incremental state costs. This leaves the potentially awkward problem of flowing subsidies between services or even between exchange and interexchange carriers at the state level. If access is priced at a lower rate than incremental costs, it increases the potential problem of flowing subsidies between carriers. Such intrastate subsidy flows cannot be sustained for long in a competitive environment.

The solution is to move quickly toward cost-based rates, for deviations from this principle readily cross jurisdictional

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lines. If nontraffic sensitive costs were recovered on a flat rate basis and traffic sensitive costs were deaveraged, the fact that the same facilities are used for inter- and intrastate access would ensure that interstate parity would pose no problem for the states.

COMMENTS

Roy L. Morris

The issues of universal service and access charges have been strongly intertwined over the last several years. This has flowed from the underlying premises that cost-based access pricing and universal service are mutually exclusive outcomes. As pointed out in the paper by Kenneth Gordon and John Harling, the externalities of universal service are both small and local in nature. I strongly agree with the conclusion of the Lewis Perl study, cited by Gordon and Harling, that the modest consumption externality at the local level cannot justify interregional cross-subsidies. Placed in more concrete terms, the subsidies for access for New York telephone users should be paid by New Yorkers, while the subsidies for access in North Dakota should be paid for by the telephone users of North Dakota.

Cost-based pricing is no longer an option; it is a necessity. The threat of uneconomic bypass has been and will continue to be a major threat unless cost-based pricing of local access becomes a reality.1 Thus, the universal service objective must be achieved in a way that is compatible with cost-based pricing. Targeted subsidies achieve the desired outcome. Gordon and Harling correctly point out that targeted subsidies are the fairer and more efficient means of assuring

Note: The views expressed here are the author's and do not necessarily reflect those of MCI Communications Corporation or any other members of its staff.
universal service.

**Jurisdictional Separations**

A major obstacle to dealing effectively with the universal service problem is the existing federal/state jurisdictional split of responsibility over access pricing. The FCC is limited to dealing with "interstate" rates and costs; the state jurisdictions are delegated authority over the remaining costs and the rates necessary for their recovery. Interstate and intrastate access charge rate structures are inherently interactive. While both individually may attempt to address the universal service problem, in combination each may dilute or undermine the effects of the other. For example, each may inadvertently tax a group of users that the other is attempting to subsidize. This outcome is highly probable given the "shotgun" approaches utilized under the present subsidy scheme.

Richard Stannard points out that the time has come for repudiating the existing jurisdictional separations process. He sets forth an alternative approach which would provide for state regulation over all exchange access within federal guidelines. The time has come for giving serious consideration to the total revamping of the division of jurisdictional responsibilities. Stannard's suggestion is a very good one. It would give the states far more flexibility for addressing the inherently local concerns for universal service. At the same time, federal interests can be protected. The framework Stannard suggests (that is, state regulation within federal guidelines) is similar to the proposal set forth by FCC Commissioner Anne Jones in her separate statement on access charges. The so-called Jones plan allowed for any number of rate combinations and provisions (that is, a flat fee plus a usage fee) with unrestricted resale and prohibitions on any class-of-service or the latter two provisions would provide a market constraint on the degree of subsidization that could occur between one access rate schedule and another.

**Peak/Off-Peak Pricing**

Nina Cornell et al. correctly point out the need for peak/off-peak pricing of access charges. Local as well as long-distance networks are engineered to accommodate peak loads. It is most efficient for low-traffic to pick up a larger share of the costs of local access. Public welfare gains are achieved because of the increased off-peak calling that results from the lower off-peak pricing. The result is more efficient use of the traffic causing the costs (peak load traffic) is recovering more of the costs of the local network.

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**Economics of Scale and the Market for Equal Access**

Brian Sullivan's paper poses two questionable hypotheses: (1) OCCs presently offer cheaper service because of their lower price of access to the local network; and (2) there will be a small market for equal access.

Sullivan's paper does acknowledge the severe interferences of the access that OCCs presently get. He does not acknowledge the dollar value that premium quality access bestows exclusively upon AT&T. The general consensus appears to be that the premium access is worth at least $7 to $11 billion per year to AT&T (see, for example, MCI Petition for Further Reconsideration in Docket 78-72, November 1983). This translates into approximately 4.5 to 7 cents per minute of exchange access. This is in the range of the actual discount (or "premium") that OCCs currently receive under the ENFIA arrangement (6 to 7 cents per minute of exchange access). Thus, the effective discount (per minute discount minus the value of premium access) is approximately zero in 1983 assuming the current level of ENFIA payments. This fact directly contradicts Sullivan's assertion that the discount OCCs offer is primarily due to the "discount" OCCs get in access pricing. Only part of the difference between the OCCs' lower prices and AT&T's higher prices is attributable to the lower price of inferior access. The fact that OCCs, such as MCI, are both more profitable and growing proportionately faster than AT&T under effectively equal costs of access indicates that these carriers may be inherently lower cost than AT&T. This is despite AT&T's larger plant size. This would be in direct contradiction to the notion that the size of a carrier's facilities is a primary determinant of its efficiencies (that is, some believe there are very large economies of scale in the intrastate market). Given the smaller sizes of MCI and the other OCCs, their current profitability can be explained by their organizational efficiencies. What MCI lacks in facility size (scale economies), it makes up for in organizational efficiencies.

This brings us to the other hypothesis Sullivan draws with respect to the future market for equal access: "If, as is commonly assumed, there are economies of scale in intercity transport then equal access would serve the carrier with the largest market share." One cannot disagree with the logic, but the facts dispute the existence of economies of scale in the intercity market, as demonstrated earlier. In fact, the over-riding effect of organizational efficiencies (such as higher worker productivity and better marketing) will be the basis for competition. Equal access at equal prices will only equalize the competitive positions of the OCCs vis-a-vis AT&T, the current premium grade carrier. The market will support a number of various
size and type competitors serving overlapping and specialized customer needs. Some competitors may choose to utilize substandard grades of access. The degree will depend upon the price/performance of the differing grades of widely available access offerings. Although Sullivan has made an honest attempt at looking at the future, I believe that he has premised his conclusions upon outdated facts and purported facts that border on myths from a different era. The makeup and dynamics of future markets will remain a mystery until truly equal interconnection at equal prices is available to all intercity competitors.

Notes


3. "Reasonable and informed people . . . can come to quite different conclusions on these issues [of economies of scale]. Indeed this happened in the course of FCC Docket 20003. In this docket, the FCC, using a survey prepared by TIE . . . concluded that there probably were economies of scale in the range of .1 to .23" [E greater than 1, denoting economies of scale; E less than 1, representing diseconomies of scale; E = 1, indicating constant returns to scale]. J. Meyer et al., "Natural Monopoly and Economies of Scale," The Economics of Competition in the Telecommunications Industry, chapter 4 (Cambridge, Mass.: Ballinger, 1980), p. 121.


5. For a peek at what the future regulation of AT&T might look like, see R. L. Morris, "A Roadmap for Deregulating AT&T," in proceedings from the Eleventh Annual Teleco...
I assume that economists, like other scientists, would agree that the purpose of theory is to help us understand and predict change in the real world. How should we define this reality which confronts us?

On another panel I remarked that we were living in a period of structural catalysis in the telecommunications area. Deregulation and divestiture mean that the jungle of the very imperfect market is reclaiming its own. It reminds me of the story of the elephants dancing in the chicken yard; it is fun for the elephants, but what happens to the chickens? We are in the middle of a battle of big oligopolists and monopolists.

Let me amend that remark. Telecommunications has made a qualitative leap in the past ten to fifteen years. From being a necessary but sort of incidental aid to the management of business organization with a relatively small share of the budget, it has now become a major productive input thanks to computers, automation, robotics, and the telecommunications services which link them to the heart of the enterprise’s production process; and with a large and growing budget. Telecommunications is at the cutting edge of applied high technology in business, government, and the military.

When I was a student at Berkeley, Leo Robin taught us that economic theory (and theorists) fall into two classes. The first type is concerned with the real world of action and change, moving through processes of contradictions. In it asymmetry is the rule, equilibrium exceptional and transitory. I must curb the temptation to explore its methodology further now. The second type dealt intellectually (politically was another matter) with the indoor sport. Deluged by logic and abstractions from the real world, it spun its logical and mathematical models. Neoclassical economics for about the last hundred years was this intellectual exercise on the assumption that there was perfect competition and total laissez-faire in the real world. Of course this was not true, but they did not mind that, and here is where their politics showed. Perhaps if their theoretical models were sufficiently clear and appealing, the actors in the real world would conform to them. So they, in time, popularized marginal and incremental cost. Company management and their friends in regulatory agencies and universities advocated marginal analysis in regulation. The result has been a shield to protect arbitrary pricing unhampered by concern over cross-subsidies from the monopoly services. Indeed, the incremental cost rationale is equivalent to value of service in this regard.

Incremental costs are subjective, infinitely different depending on the mix of assumptions as to the parameters of the decision-making process to which they implicitly refer, and the optimism or pessimism of the executives assumed to be facing these parameters. William Melody has spelled out in detail at former meetings of this group the defects in marginal analysis so I will not go through it now. I do agree with him.

Richard Stannard’s paper suffers from his uncritical adaptation of these concepts. He seeks to compare incremental cost estimates with embedded costs. The latter have some basis in historical reality in the real world. The former do not. So I am sorry to say it, but the comparison Stannard tries to make is meaningless. It will not work.

There are two types of theory relevant to the “outdoor” sport in the real world of telecommunications markets. One of these is investment-driven cost/pricing relationships. This is the theory which guides the firm in allocating its resources and recovering costs. It also is applied within firms which have operations decentralized into profit centers. As applied through fully distributed costs and supplemented with opportunity costs derived objectively from stand-alone cost studies, it provides a realistic basis for management and regulators. As opposed to subjective, idealist marginal speculations it offers realism for evaluating cost-based prices, or controlled cross-subsidies where for some public policy purposes departures from strict cost-based pricing may be justified. Melody has written and spoken on this line of theory, and again I agree with him.

The second line of realistic theory deals directly with the policy aspects of the contradictions in the industry, between this industry and others, and between industry and others.
government. The world and life move via contradictions, but some are more central and all embracing than others. At any given time it is possible to identify one as the principal contradiction. The principal contradiction now is between capital-intensive technology and people. I mean people looked at as employees (where they face automation at the workplace) and as consumers (where they face automation at the "Instabank"). Structurally, it is the contradiction between, on the one hand, the giant corporations and a small number of high-income individuals and, on the other hand, small and medium-sized business organizations and the rest of individual consumers. While this contradiction is systemic it is particularly evident in telecommunications, where the technological dynamic frontier exists and where the currently dramatic evidence appears.

Several panelists have referred to the analogies between what is happening in telecommunications and in air transport. One could add the postal service. The common characteristics appear no matter in what sector we examine this principal contradiction. These are the degradation of standards (including quality) for formerly generally available services, the degradation of the quality of life and of the environment, and the increasing prices in a system experiencing chronic stagnation. John Haring's argument against special concern for the poor and the elderly demonstrates the generality of the contradiction as well as his bias in social policy matters.

In analyzing the deregulation and decentralization process it is helpful to focus consciously on its contradictory aspects. Brian Sullivan does that very well. His paper deals with the relations in the real world of giant corporations, billions of dollars, tariffs to be filed, and facilities to be enhanced. It is refreshing to find a paper almost totally free from the fog of talk about marginal cost pricing, obscuring the struggle in the real world. Moreover, he poses the vital question: Who will pay the substantial costs to upgrade the exchange and other Interata facilities to meet FCC standards for the optional tariffs for OCC and other dealers in Interata channels? The BOCs, ATT, or the OCC? I would add: Are these investments to be added to the local loops and dumped in the catch-all "access line" category?

As a political economist I applaud Sullivan's recognition that there are "social costs measured in an enhanced choice of service providers and a redistribution of wealth among customers." As he says, "the beneficiaries of equal access, other than a blanket statement about heavy users of long distance calling, are not obvious." Such a careful approach to the real, contradictory world if more generally practiced would speed the resolution of the present confusion. I suspect that the beneficiaries of the enhanced services will turn out to be the producers who will use them in the production
Part Six:
Regulatory Treatment of
Excess Capacity, Costly Plant, and
Premature Retirements
RATEMAKING TREATMENT OF EXCESS CAPACITY:
RECONCILING REGULATION WITH CONSUMER SOVEREIGNTY

Basil L. Copeland, Jr.

The consequences for ratemaking of excess capacity, along with costly plant and premature retirements, may constitute the most serious challenge to ratebase regulation of our time. If so, and if any of the radical departures from traditional ratebase regulation now being proposed are widely adopted, the irony of this fact should not escape notice. Nonlinear ratebase regulation as we know it may prove to be a victim of inflation, but if so it will be for wholly unexpected reasons. Original cost ratebase regulation has long had its critics, including many who argued that it would not fairly (or efficiently) price the cost of utility assets during periods of inflation. Almost always the focus of such arguments was upon what was (purportedly) fair to the investor. For good reason, these arguments were ignored, and original cost remained for a long period the dominant method of determining an appropriate cost level for ratemaking purposes. Original cost ratebase regulation even survived previous inflations without encountering the significant problems it now faces. To the extent, then, that traditional ratebase regulation becomes a victim in one fashion or another of inflation, it will not be because of its inability to compensate investors fairly during periods of inflation, but because of an inability to respond to changes in consumer demand in such a way as to preserve any semblance of consumer sovereignty.

It will certainly serve to sharpen the focus of our
discussion of this issue if I set forth my thesis in the most provocative manner possible. Stated briefly, beginning in the late 1960s and early 1970s, a sea change occurred in the economics of electric power production that fundamentally altered the characteristics of the industry and made the resulting cost of service far more sensitive to inflation than would have otherwise been the case. Two changes deserve special attention because together they fundamentally altered the cost characteristics of electric power production. The first was the exhaustion of economies of scale and the end of technological progress in electric power production. The second was a simultaneous explosion in real factor prices: principally fuel and capital, but to some extent labor as well.

Together these forces set in motion a chain reaction that has not yet fully played itself out. After several decades of falling real prices, the consumers of electricity began to see the cost of electricity escalate in real terms. Simultaneously, long-term trends in the increase in real per capita income moderated dramatically. In a manner not at all surprising to economists, but which certainly took utility system planners by surprise, load growth also moderated dramatically. In addition, response to rising prices and stagnating incomes. As a consequence, by the end of the 1970s utility reserve margins were far above the level that had been justified historically as adequate to maintain system reliability.

In short, utility systems were significantly overbuilt with respect to current demand. Utilities sought, nevertheless, to include this excess capacity in their rate bases, setting the stage for the current conflict. That is not to say, of course, that ingenious arguments were not soon forthcoming to justify this sudden increase in capacity. I shall at the appropriate time consider these arguments for what they are worth, but they all fundamentally ignore one thing: What were consumers telling us in responding as they did to rising prices and stagnating incomes, and what responsibility does regulation have to the expression of consumer sentiment? I am not oblivious, of course, to the balance between consumer and investor interests that regulation is frequently said to entail. In fact, it is in the interest of this objective that I wish to consider the significance of the concept of consumer sovereignty. While those who would advocate the investor interest will no doubt see things differently, a key theme in this presentation is the premise that if regulation has any social legitimacy whatever, it can no longer empower the consumers of monopoly services with the same degree of sovereignty that they would enjoy under more noticeably competitive circumstances. Now regulation is in fact to accomplish this objective when it depends upon private investors for capital.

Excess Capacity

Electric utility load forecasting has been described as a process of "looking forward through a rear-view mirror." The metaphor is certainly apt, but it should not cause us such amazement that we despair of the practice altogether. A great deal depends upon the direction in which the rear-view mirror is focused. Many different views or glimpses of the past are possible, and each tells a little different story. It is even possible to focus the mirror in such a way as not to see what is actually there. Something of this sort seems to have taken place in the electric utility industry. It was not until the end of the 1970s that utility system planners and corporate decision makers began to wake up and realize that the elasticity of demand for electric power could no longer be ignored. Prior to that the declining rate of growth in electric power consumption was frequently attributed to random exogenous forces that were not expected.
to alter long-run growth trends. There are still those who hold to this view, although their expectations are somewhat moderated by successive failures to find "light at the end of the tunnel." No useful purpose is served, however, by blaming the lack of growth in the economy on recessions and mild summers. More fundamental forces are at work, and any intelligent assessment of the future requires, first, an intelligent assessment of the past.

Most of what follows focuses on changing cost characteristics in the electric power industry. These are changes that the industry has the least excuse for ignoring. Equally important, however, are long-run structural changes in the economy as it shifts away from energy-intensive mass production forms of industrial activity toward information-intensive high value-added modes of production. It is not as energy intensive as the former. The so-called computer revolution is a case in point. Regardless of the extent to which computers will ultimately affect the computer industry has generated a considerable amount of "industrial" activity in recent years. Two of the most significant factors about the recent "recession" were that it was industry-specific and that, in the midst of recession, a great deal of new industrial or commercial activity was spawned. This suggests that the recession was due less to a lack of general effective demand in the classical Keynesian sense than to a lack of specific effective demand in certain key sectors of the economy. It is not my intention here to discuss the question of industrial policy or the issue of public policy toward "sunrise" and "sunset" industries. I merely seek to draw attention to the fact that fundamental structural changes in the economy, and not that there is obvious import in this with regard to the effect of recession on the demand for electricity. Even if the economy undergoes a general recovery and grows at an otherwise healthy pace, that does not assure recovery in industries which consume considerable quantities of electricity. Some underlying structural shift in the GNP/energy ratio is taking place, and utilities would be foolish to ignore this fact.

This brings us to the substantive portion of this part of our analysis. One likely reason for the underlying structural shift in the GNP/energy ratio is the escalating cost of energy, while the current oil glut may delude some into thinking that the problems of the 1970s are safely behind us, that certainly is not the case in the electric power industry (and I do not think it to be the case in the oil industry either). With respect to the electric power industry, there are some signs that the worst is yet to come, but these signs are not apparent without a clear sense of what has happened in the past.

In my introductory remarks I made reference to two significant changes in the electric power industry that have fundamentally altered cost characteristics. The first has to do with the end of technological progress and the exhaustion of economies of scale in the industry. Some sense of this fundamental change is suggested by Figure 1. Three important time series are plotted in this figure. The first is the national average heat rate for fossil-fuel steam-electric plants. This is the clearest single measure available of the historical effect of cost-saving technological progress in the industry. It is also a measure, to a somewhat lesser extent, of the historical effect of economies of scale in electric power production. After several decades of dramatic decline, heat rates leveled off in the mid-1960s and have remained essentially constant since. This is despite, as the figure shows, a dramatic upward trend in average plant size for new fossil-fuel units placed in service. Equally dramatic is the escalation in average installed cost per kw of new fossil-fuel units. It is significant to note that two distinct trends in the escalation of installed costs are observable and that in each case the escalation in plant costs exceeded the general rate of inflation for the period in question. In the first period, 1967-75, plant costs escalated at the rate of 7.8 percent per year, while the general rate of inflation averaged 5.7 percent. Throughout the late 1950s and 1970s the cost of construction thus escalated in real terms, despite a substantial increase in average unit size. Moreover, real costs escalated much more rapidly during the second period than during the first—3.6 percent per year versus 2.1 percent per year, respectively. This escalation in plant costs cannot therefore be attributed solely to rising cost inflation and certainly refutes questions regarding the so-called economies of scale that were expected to be obtained with larger unit size.

An additional fundamental change in underlying cost conditions was an explosion in fuel prices, illustrated by Figure 2. Although the rising price of oil and gas is well known, it is equally significant that the price of coal has escalated also. Although coal markets vary significantly by region in terms of structural characteristics, it is still surprising that coal prices have remained as firm as they are in the light of the general supply and demand conditions existing in the coal industry. In any event, the point is that all fuel prices have undergone significant upward shifts that have affected in equally significant ways the cost of electric power production.

Taken together, these two fundamental shifts—the exhaustion of economies of scale and technical progress, on the one hand, and rising factor prices, especially for fuel, on the other—reversed the trend of declining real average costs that consumers of electricity had enjoyed for decades. Moreover, as Figure 3 shows, real average costs did not merely

Figure 1. Cost and Productivity Trends in the Electric Utility Industry


Figure 2. Fuel Cost Trends for Electric Power Production
stop declining; they began to rise. After falling to a low of 4.25 cents/kWh (all figures in 1980 dollars) in 1970, prices steadily rose throughout the 1970s to 4.73 cents/kWh in 1980 and to 5.29 cents/kWh in 1982. By 1980, then, rising electric utility prices had restored the average real cost of electricity to the level that existed in 1960 (4.70 cents/kWh).

This, coupled with the poor performance of the economy during the 1970s, caused consumers (broadly conceived to include all users of electricity, including industrial users) to alter consumption patterns radically. The rate of growth in the demand for electricity fell to half its former level. Utility system planners and corporate decision makers were slow to admit this was anything more than temporary. Many even refused to admit the demand for electricity was at all sensitive to price. Although load projections fell gradually throughout the period, the reaction was always delayed, and as load forecasts were pared back, consumption was pared back even more. As a result, large construction programs started during the 1970s simply proved excessive relative to the level of demand that existed by the end of the decade.

By that time system reserve margins were nearly twice the minimum load required for system reliability (see Table 1). My point in repeating this story is to emphasize that reserve margins by the end of the decade were significantly higher than historically considered adequate for purposes of system reliability by accident, not by design. If the mistakes of the 1970s are not to be repeated during the 1980s, this fact must not be forgotten. Moreover, it is equally important to remember why reserve margins rose so rapidly: At the very least, electric utility consumption displays a significant degree of sensitivity to changing prices, and underlying changes in the structural make-up of the economy have made electricity at least somewhat less important to the economy than it used to be.

The consequences of ignoring these lessons can be explored using fairly simple analytical techniques. Figure 4 illustrates the historical trend in peak load for the United States during 1961-1982 and projects peak loads under three sets of assumptions for 1983-1995. The trend fitted through the historical period and the projections were derived from a simple Koyck lag adjustment model with average real prices, real national income per customer, and demand lagged as the principal independent variables. The projections were derived using three sets of assumptions that are particularly enlightening. The first set assumed that price and income conditions prevailing from 1961 to 1971 would prevail in the future. In other words, the glory days of yesterday would recur. Under this set of assumptions, demand increases from about 436 GW in 1982 to 955 GW in 1995, a compound annual growth rate of 6.2 percent. I know of no one who is actually
### Table 1. Historical and Projected Reserve Margins for U.S. Electric Utility Industry

<table>
<thead>
<tr>
<th>YEAR</th>
<th>INSTALLED CAPACITY (GW)</th>
<th>PEAK LOAD (GW)</th>
<th>RESERVE MARGIN (%)</th>
</tr>
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<td>1960</td>
<td>174.90</td>
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<td>1964</td>
<td>216.50</td>
<td>175.00</td>
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<td>226.90</td>
<td>186.30</td>
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<td>—</td>
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<td>1992P</td>
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<td>518.17</td>
<td>—</td>
</tr>
<tr>
<td>1993P</td>
<td>N/A</td>
<td>532.47</td>
<td>—</td>
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<tr>
<td>1994P</td>
<td>N/A</td>
<td>553.21</td>
<td>—</td>
</tr>
<tr>
<td>1995P</td>
<td>745.3</td>
<td>578.12</td>
<td>29.4</td>
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</table>

projecting load growth of this magnitude, and it is not presented here as a "serious" forecast. Its principal purpose is to illustrate in perspective the significance of the strong income growth and declining prices during 1961-1971 on the structure of consumer demand for electricity.

The second set of assumptions extrapolates prices and income as experienced during 1972-1982. While we might hope for the better, a continuation of the recent past is not altogether out of the question. Under this set of assumptions, demand only increases from 436 GWh to 462 GWh in 1995, a mere 0.4 percent per year. I know of no one projecting a forecast like this, either, but it should not be too quickly dismissed. In addition to assumptions regarding prices and incomes, the Keynesian adjustment model incorporates a lagged adjustment feature which suggests that we have not yet seen all of the likely structural changes in demand and consumption resulting from past price increases or reductions in income growth. Even if there should be some result in the upward ratcheting of prices and a welcome resurgence of growth in personal incomes, these welcome changes will not be an immediate stimulus to growth in the manner reflected. And when we combine the lagged effect of price changes with the assumption of further increases in the future's stagnant incomes, the effect is to produce almost no significant load growth.

The third set of assumptions is perhaps the more "realistic" of the three and attempts to approximate, as best as possible given structural differences in underlying methodology, the basic assumptions built into the most recent forecast by Electrical World. In this instance, demand grows from 436 GWh in 1992 to 576 GWh in 1995, a rate of growth of 2.1 percent per year. Given the underlying similarity of the input data and assumptions, it is interesting to note that Electrical World is forecasting a peak load of 632 GWh in 1995, as compared to the 576 GWh forecast here. (The growth rate implied by the Electrical World forecast is 2.5 percent per year.) While I can only speculate without further knowledge of the input data and assumptions, it is noticeable that the difference is attributable to the forecast to the future effect of past price changes through the lag adjustment model. In an "average" forecast presented here, the nation's utilities are progressively facing a 10 percent to 30 percent increase in capacity throughout the forecast period.

Table 1 presents further information regarding the forecasts illustrated in Figure 4 and shows what the reserve margins will be throughout the forecast period based on the mid-range forecast and current utility expansion plans. While plant cancellations and other changes in utility expansion plans are likely to change these levels, the levels depicted in Table 1, does not appear to be room for much doubt that reserve margins will continue

Excess Capacity

To be above levels historically considered adequate for system reliability for at least the remainder of this decade and possibly beyond. Reducing treatment of excess capacity is thus an issue that is likely to remain with us for some time.

Defending against Excess Capacity

The title of this section is borrowed, in a sense, from a paper by Andrew Ford and Irving Sibrabay. In it they set forth the novel suggestion that, in defending against uncertainty in utility system planning, it imposes a lesser cost on consumers to underproject than to overproject future demand. Needless to say, this is not the way utility system planners have traditionally operated. In fact, they have consistently overprojected future demand and are now seeking to defend against excess capacity (that is, explain it) before questioning and skeptical regulators. In the previous section I sought to emphasize that the present situation of excess capacity occurred quite by accident and not by design. Although I thought that was obvious, I know of several instances in which utilities have sought to defend against excess capacity by arguing consumers were better off for all this excess capacity they are suddenly having to pay for. Although they have shied away from stating outright that they arrived where they are today--with reserve margins of 30 percent to 40 percent--by design rather than by accident, a move certainly does appear to be shoddy to reflect criticism from high reserve margins by arguing that high reserve margins are too bad after all. I cannot refrain from commenting about the curious quality of all this. If such reserve margins are not in the consumer's interest, then why did management not consciously pursue such an objective in the first place? Are we really to believe that consumers are now better off because management failed in its objectives, that is, failed to predict future plant requirements accurately? To the consumer this sounds a little bit like "Heads I win, tails you lose," with utility management as the "I." One common approach to defending against excess capacity is to argue that reserve margins historically considered adequate for system reliability purposes are no longer appropriate. In part this is true, but more is frequently made for this claim than is deserved. Historically, system reserve requirements have been based on the need to have sufficient "excess" capacity at system peak to maintain reliability in the event of unscheduled outages. It was a pure "machines breaking down" concept of the need for excess capacity. In economic terms, it was totally supply-side oriented. The more sophisticated utility systems based their reserve requirement upon probabilistic studies of unscheduled outages such as loss of load probability (LOLP). Others employed
simpler techniques, such as maintaining reserve capacity equal to 1.5 times the largest single unit. Regardless of the method employed, a kind of consensus evolved that a reserve of 15-20 percent of expected peak load was adequate to maintain this kind of system reliability, and this consensus was frequently materialized in the reserve margins agreed upon in power-pooling arrangements.

These agreed-upon reserve margins have become embarrassing now that utilities on the average have about twice the necessary capacity to meet these requirements, and no small amount of effort has been devoted to discounting the historical consensus. This is done most frequently by pointing out that average unit size is now much larger and that larger units have lower availability at higher forced outage rates. While this is true, it does not justify a 50-100 percent increase in required reserves. It is also unlikely that the increase in required reserves associated with larger units was ever considered in the planning stages when the decision was made to build a large central station plant because of its purported "economy" of scale. In any event, it is unlikely that the upward trend in average unit size can justify more than a 20 percent increase in system reserve requirements to maintain the same degree of system reliability achieved previously with smaller plants.12

Another argument that has been seized upon to defend against excess capacity is the "oil-backout" argument. According to this argument, the economic benefits of reducing the use of oil as a boiler fuel (or in a few instances, natural gas) are so substantial that it is cost effective to install additional capacity to cover this displaced capacity even though this results in reserve margins considerably above the reserve margins required simply to maintain system reliability. We should not doubt for a moment that this is true for some systems and up to a certain point, although we have reason to wonder whether this argument is now as compelling as it was a couple of years ago when it was first advanced. But, as a study done by this writer two years ago indicated for a system with a fairly typical load share that it could economically serve as much as 40 percent of its annual load with off-fired combustion turbines. A study done by this writer two years ago indicated for a system with a fairly typical load share that it could economically serve as much as 40 percent of its annual load with off-fired combustion turbines. A study done by this writer two years ago indicated for a system with a fairly typical load share that it could economically serve as much as 40 percent of its annual load with off-fired combustion turbines.

This argument holds true in spades for nuclear power plants. No system planner in his right mind would select nuclear generation to displace off-fired capacity that operates as intermediate or peaking capacity.13 This argument holds true in spades for nuclear power plants. No system planner in his right mind would select nuclear generation to displace off-fired capacity that operates as intermediate or peaking capacity.

Another way to assess the claim that "excess" capacity is justified on the basis of oil-backout is to determine whether this was a rationale consciously considered in the planning stages or whether it was an argument developed ad hoc to rationalize excess capacity that materialized by accident rather than by design. One should also, in this regard, examine whether the planning process considered the design differences required to operate a high-pressure coal-fired steam turbine, for instance, in a load-following cyclic mode of operation. Coal plants designed for true baseload operation simply are not designed to displace off-fired capacity that operates as intermediate or peaking capacity.15

This argument holds true in spades for nuclear power plants. No system planner in his right mind would select nuclear generation to displace off-fired capacity that operates as intermediate or peaking capacity.

Although I risk anticipating arguments developed more fully below, there is a strategy regulatory agencies could pursue in those instances in which "excess" capacity is justified on the basis of oil-backout. Where the economic benefits of displacing oil generation in fact justify adding new capacity for this purpose, the economic benefits ought to be sufficient to take the displaced capacity out of the ratebase without adversely affecting the company's stockholders. In such cases, a utility would be indifferent either to (1) adding the new plant to the ratebase and subtracting from the ratebase the plants that are displaced, or (2) leaving the new plant out of the ratebase entirely as long as the firm is not required to flow the fuel cost savings back to ratepayers through a fuel adjustment clause. Ordinarily, the fuel cost savings from new plant are not enough to offset claims. Even at real oil prices approximately twice current levels, it is still economical at the margin (that is, when considering new construction) to serve significant fractions of a utility's average annual load with oil-fired combustion turbines.16 For systems with aging oil-fired steam turbine capacity, such capacity can be used in this way rather than installing new oil-fired capacity. But it makes absolutely no economic sense whatsoever to displace this capacity with new nuclear-fired capacity because of purported benefits from backing off of oil. At best, the oil-backout argument has relevance only for those systems which use oil-fired steam turbine plants for baseload generation. In that instance, there may be an economic rationale for installing some "excess" capacity to back off of oil, but even then the argument should be scrutinized very carefully.

Beyond the merely rhetorical nature of the question just posed, I would add that implicitly outage costs always have
been considered in establishing appropriate reserve margins. Consider the classic standard of one day in ten years frequently employed in LOLP studies. Where did this number come from? Why not one day in five years? Or twenty years? I suspect that an implicit recognition of a trade-off between cost and avoiding a power outage at any cost was in large measure responsible for the standard established. Having seen some of the newer studies that attempt to incorporate explicit modeling of outage costs, I am not sure such progress is evident in this regard. One study found that the appropriate reserve margin ranged from about 19-21 percent over a very wide range of assumptions about the cost of outages.16 If this is typical, I suggest that a utility which raises the question of the cost of outages when defending against excess capacity gains more value from the emotional effect brought about by raising the specter of brownouts and blackouts than from any substantive defense of excess capacity.

Legislative Approaches to the Excess Capacity Issue

Regulation is a victim of its past. And above all else, its past is one of litigation, beginning with the old condemnation analogy in which regulation was viewed legally as the "taking" of property for which the owners were entitled to fair compensation ("fair return" on [11 "fair value"). It is not surprising, then, that the issue of excess capacity should be couched in legalistic terms, as if it were a simple a legal matter regarding what actions a commission can or cannot take when confronted with excess capacity which has installed more capacity than required to meet consumer demand adequately. Before discussing the implications of consumer sovereignty in this regard, I will review the legal framework in which this issue is frequently evaluated.

The first step is typically to define excess capacity as capacity over and above that required to meet the peak demand on the grid.17 The definition of excess capacity required to ensure that there is a margin to allow for day-to-day variations in the operating condition of the system.18 The emphasis is clearly on system reliability, that is, having enough capacity to meet the peak after a reasonable allowance for unexpected and unscheduled outages. The reserve margin required to satisfy such a definition varies from system to system, but some indication of what is appropriate is given by the fact that most power pools require a minimum reserve of 15-20 percent. Capacity above some agreed-upon reserve would be a starting place for a factual legal determination that a utility's generating system is overbuilt.19 At least three different tests have been used to determine whether capacity in excess of a specified reserve margin should be charged to ratepayers. The first of these is the prudent investment rule. Its purpose is to determine whether the excess capacity resulted from circumstances beyond the reasonable control of management. Utility system planning is inherently uncertain, and some level of excess capacity can reasonably result from forecasting errors. The real significance of the prudent investment test is its emphasis on those instances in which utilities invest in excess capacity with prior knowledge that the level of investment undertaken will not be needed to meet load requirements. The prudent investment rule was applied by the Missouri Public Service Commission as a basis for excluding Kansas City Power & Light Company's investment in Lathan 3 from its ratebase. The commission concluded that (1) the company could have provided safe and adequate service without the plant, (2) the company's management had prior knowledge that there would be excess capacity once the plant was complete, a fact demonstrated by its effort to underestimate plant capacity and to sell off capacity at a loss to nonjurisdictional customers, and (3) the company ignored capacity studies suggesting alternatives to new construction.20

Some utilities have argued that unless imprudence is established, excess capacity cannot be disallowed for rate-making purposes. This argument was advanced by Northern States Power on appeal of an excess capacity decision by the South Dakota Public Utilities Commission. Citing Supreme Court case law dating from the turn of the century, the court rejected the claim by Northern States Power that a commission must make a prerequisite fact finding, supported by the record, that a company's excess capacity is the result of managerial imprudence before it can disallow costs associated with excess capacity.21

Recognizing that the prudent investment test is not dispositive in many circumstances, another frequently employed is the used and useful test.22 The mere fact that investments were prudent when made does not mean it is appropriate to burden ratepayers with the cost of capacity which later turns out to be unnecessary.23 Managerial decisions always involve an element of risk. Risk for which investors are compensated in the cost of capital. When management makes a decision to invest in a new plant to meet projected future demands, there is always the risk that the projected level will fail to materialize and that the plant will not be required. In such instances, should the stockholders or the ratepayers bear the resulting loss? The used and useful test recognizes a limit to ratepayers' liability. If a plant is not used and useful, it can still be excluded from ratebase under this rule even though the original decision to construct the plant was made without prior knowledge that it would result in excess capacity. The used and useful test merely places the risk of managerial decision making where it properly belongs: on the shoulders of the firm and not on the backs
of the consumers.\textsuperscript{23} A third rule that has been applied is the benefit-cost test. This seeks to recognize the fact that reserve margins are not the sole determinant of new plant. Older plant may become economically obsolete before it reaches the end of its "useful" life. In such cases, the cost of building new plant will be more than offset by the economic benefits associated with replacing plant that is more expensive to operate. A current example is the substitution of new coal-fired baseload capacity for oil-fired baseload capacity in some states. When baseload capacity is used to meet baseload energy requirements, the benefits of replacing serviceable plant may exceed the costs of doing so. But, as argued earlier, where this is the case, the economic benefits of replacing serviceable plant ought to be sufficient to take the displaced capacity out of the ratebase without adversely affecting the company's stockholder. Looked at somewhat differently, the costs of premature retirement of serviceable plant ought to be added to the costs of the new plant in any benefit-cost analysis of this type. Only if the benefits are such as to offset both the cost of constructing the new facility and the cost of retiring the old facility has this approach any merit as an economic test of benefits and costs.

Below I will discuss what I perceive to be some of the limitations of the legalistic approach to ratemaking treatment of excess capacity. Before I do that, however, I wish to review some of the actual ratemaking techniques that have evolved in response to this issue. Reflecting the historical character of the ratebase regulation, the revenue requirements frequently take the form of a ratebase adjustment. The simplest and most direct method is to exclude the excess capacity from the ratebase. When this approach is employed, it is to be understood that the investment was either imprudent initially and/or is no longer used and useful. Another type of ratebase adjustment is to attribute where new plant is more economical than old plant, is to eliminate the old plant from the ratebase.\textsuperscript{24} But if this method is not to burden ratpayers unfairly with the higher capital costs of new plant, excess capacity will be needed at that the fuel cost savings will, in fact, offset the higher capital costs.

A variation is to eliminate the current return but allow the continued capitalization of carrying costs. Much like construction work in progress, the capacity at issue remains out of the ratebase, but the firm is able to continue to accrue the equivalent of AFUDC. Reflecting the balancing of equities that legalistic approaches attempt to accomplish, this might be appropriate in instances in which it has been determined that present excess capacity will be needed at a determinable point in the future. In order that the financial risk of this temporary excess capacity be borne by the appropriate party, it would seem appropriate that the AFUDC rate used for accruing the carrying costs of this excess capacity include the equity return component at a zero cost level. In this instance, the AFUDC rate would represent only the embedded cost of debt and preferred stock at the time of the declaration of capacity excess and would, therefore, be lower than the rate that the company would be applying to new construction. This approach would also require a cessation of annual depreciation expense. There are implications to consider, however. By eliminating the equity component, the company's stockholders are properly (in my opinion) not being given the opportunity to accrue a return on the excess capacity. They are, however, spared the full burden of the debt costs associated with the excess capacity. So, although present customers avoid any costs associated with not procuring the excess capacity, future customers would be required to pay those costs even though they had no responsibility for them. From the standpoint of consumers, this is clearly a modest adjustment that would be appropriate only where there is some particular reason to strike a balance between competing interests.\textsuperscript{25}

Something along this line, but with significant differences, was recently proposed by Public Service Company of New Mexico as a method of dealing with the excess capacity issue it faces.\textsuperscript{26} It proposed to "inventory" its excess capacity (capacity above a 20 percent reserve margin) and it would continue to accrue a full AFUDC rate on the inventoried capacity, but it would credit toward the reduction of the capitalized carrying charges revenues in excess of revenues from any off-system sales made from the inventoried capacity. This is reminiscent of a second class of excess capacity adjustments that can be referred to as revenue adjustment. Rather than take the excess capacity out of the ratebase, additional revenue is sometimes imputed to reflect the rental value of excess capacity.\textsuperscript{27} As sometimes applied, this does not require a finding that an actual market exists for sale of surplus power. This approach can involve merely assuming that such sales are made and imputing the revenues that would result from such sales to the company's test year revenue. This protects the jurisdictional ratpayers from the burden imposed by the excess capacity. Since this approach has met with a certain degree of court resistance, a more appropriate method, which would have the same effect, would be a ratebase adjustment that treats excess capacity as nonjurisdictional plant.\textsuperscript{28} In such instances, one merely could credit a jurisdictional separation that allocates the excess capacity to the nonjurisdictional component of the plant in service. In this case, the separation should be complete: Any revenues that have been received from the sale of excess capacity and any expenses associated with the excess capacity should
be allocated to the nonjurisdictional component of the cost of service.

Limitations to the Legalistic Approach

Although the previous approaches are suitable for application on an ad hoc basis depending on circumstances as they vary from jurisdiction to jurisdiction, the legalistic approach to ratemaking treatment of excess capacity suffers from a number of deficiencies. First, legal precedent is frequently inconsistent and varies among jurisdictions. A serious vacuum exists in this area of inquiry because it is not clear whether economic reality dictates the application of legal concepts in regulation or vice versa. Second, a clear consensus as to the appropriate economic principles, regulation muddles through by applying old and familiar, but frequently outdated, legal concepts to a changing world. This is evident, for example, in the view held by some that managerial imprudence is a prerequisite finding before the costs of excess capacity can be disallowed. This view stems, no doubt, as does the used and useful concept, from the excessively rigid view of the legal framework surrounding traditional ratebase regulation, especially the significance of the very concept of a "ratebase." While the ratebase approach is an administratively convenient and highly flexible approach to ratemaking, it is certainly not the only way to determine the cost of service. If the legal framework of regulation is not sufficiently flexible to allow radical departures from traditional ratebase regulation—and I happen to think that it is—then it is time to work on changing this framework.

A similar problem arises with the "used and useful" concept and illustrates further the limitations of a legalistic approach to ratebase regulation. In a purely physical or engineering sense, new plant which is clearly excess with respect to system needs need not be used and useful in the sense that it operates under economic dispatch to displace plant previously ruled by to meet system load requirements. While this displacement argument makes the prior plant no longer used and useful in the sense that it once was, eliminating the prior plant from the ratebase is not necessarily an adequate remedy from the consumer's point of view. Such plant is likely to be considerably depreciated, and even on an undepreciated basis older plant is likely to have a lower installed cost than more recently installed plant. In many cases replacing this old plant from the ratebase simply not a sufficient response from the standpoint of the total costs of doing so by a new plant which represents excess capacity. The problem, of course, owes to the fact that economic dispatch looks back at separable costs, not at the total costs imposed on consumers by the addition of new plant. To overcome this limitation, the

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used and useful concept must either be discarded or reinterpreted. As long as the ratebase approach remains the dominant method of rate setting, it would be unwise to discard the concept altogether, and I would therefore suggest that it be reinterpreted to emphasize its "use value," not in the physical or engineering sense, but from the standpoint of its "use value" to consumers. From the consumer point of view, use value reflects the fact that the plant is required either in an absolute sense to supply the demand for service or in the sense that it reduces the total cost of service. Plant which is not required to render service in an absolute sense and which does not reduce the total cost of service to consumers should not be euphemistically labeled "used and useful" merely because it has lower variable costs and is therefore loaded ahead of older plant under economic dispatch.

Recognizing Consumer Sovereignty in the Ratemaking Process

The previous limitations to what I call the legalistic approaches owe generally to an excessively rigid interpretation of ratemaking, one that relies on the traditional ratebase approach to regulation at if were the only one available. As long as the focus is on whether excess capacity should be "in" or "out" of the ratebase, the debate will rage terminally as to whether any given investment was "prudently" incurred, it "used or useful," and so forth. In this section I wish to suggest an alternative approach, one entirely in keeping with the historical purpose of regulation and arguably within the broad range of permissible actions allowed by the "end result" doctrine of the Hope Natural Gas case. I take as a starting point the premise that regulation in an industry generally considered a natural monopoly exists to accomplish the same results ordinarily achieved by competition in unregulated markets. Although other theories of regulation exist, this "public interest" concept of regulation does in fact accord with the view commonly held by those who actually work in the area of regulation (as opposed to those who merely write about it).

We may begin by asking why the competitive model is so frequently relied on for policy guidance. Clearly, the answer has something to do with notions of allocative efficiency. But allocative efficiency, per se, is not in my opinion an adequate explanation of the fascination for markets as the preferred method of coordinating the production of goods and services. Certainly, the allocative efficiency of markets is generally impressive, as anyone will admit who has ever marvelled at the ability of markets to allocate just about the right amount of resources to the production of maltuk and maccasins so as to prevent malkus from piling
up in excess of demand in Maine while meecasings go in short
supply in Arizona and Nevada. We do not have to be oblivious
to imperfections in the market in order to appreciate its
efficiency in coordinating complex economic decisions with
regard to production and distribution. But the market serves
another function as well. It mediates conflict between
producers and consumers. In theory, it does more than mediate
conflict; it shifts producers of power over consumers not
only with respect to consumption decisions per se, but also
with respect to the disposition of the social surplus that
exists because of the disparity between what consumers are
willing to pay and the actual cost of production. Competitive
markets prevent producers from exploiting consumer demand.
This is the theory, at least, and for our purposes we need
not get sidetracked asking questions about how effective
markets are actually immobilizing producer power. My point
is a quite different one. My point is that in resolving
conflict between producers and consumers the market performs
quite a different function from ensuring allocative efficiency.
In fact, allocative efficiency and monopoly power are not
mutually exclusive. A monopoly capable of "perfect"
discrimination will produce the same level of output that would exist in competitive equilibrium. The
value of competition, therefore, is not just that it achieves
some measure of allocative efficiency, but that it prevents
producers from exploiting consumers.

This value of competitive markets is exemplified by
the notion of consumer sovereignty. The competitive firm
is a price taker, not a price maker. The competitive firm
can never extract from consumers more than consumers at
the margin are willing to pay. Prices in competitive markets
thus come to reflect consumer willingness to pay, not costs
of production. One of the most well-known assets of regulation
is that unregulated firms are free to set prices at any level
necessary to recover costs of production. This myth is easily
ballyed by the cutthroat competition that emerged in the airline
industry after suspension of excess capacity (low load factors)
at prevailing rates, competitive rates frequently proved inadequate to cover the out-of-pocket cost of
production, so as to recover fully their total cost of production, including fixed costs.

Given this definition, our attention is turned toward
an inquiry into the conditions under which markets would
fail to clear. In doing so, it is not necessary to rehearse
the voluminous literature on market failure because the kind
in which we are interested is not one that generally arises
in unregulated markets. The "market failure" which concerns
us is hypothetic. It is a condition under which markets
would fail to clear if firms behaved in the postulated manner.

Specifically, suppose firms in competitive markets attempted
to set prices equal to average total cost so as to recover
fully their total cost of production, including fixed costs.
If consumers are sovereign, by which we mean to imply that they have available alternative sources of supply, markets
will clear only if consumers' marginal willingness to pay
exceeds the total cost of production. If the marginal willing-
ness to pay is less than the total cost of production, markets
will not clear if producers insist on a price sufficient
to cover total costs. Competition will quickly evolve out of
out-of-pocket or variable costs, will quickly do so. The neoclassical
type of price is quite clear as to what the response of a
firm ought to be in circumstances such as these. First,
I would compare what consumers are willing to pay to its
variable costs, not its total costs. As long as it can produce

I take it that we look to the competitive model for
policy guidance because we value the outcome that it tends
to produce. With that in mind, I would like to pose the
"excess capacity" problem in an altogether different light,
that is, in the context of the competitive model. To begin
with, what do we actually mean by excess capacity? If we
are to benefit from thinking about this issue in a microecono-
metric context, we should define excess capacity in terms
sufficiently general to be applicable not only to the electric
utility industry, but also to any industry with large invest-
ments in fixed plant. This allows us to abstract initially
from problematic issues that arise in the particular context
of electric utility regulation because of the production
technology involved (such as the proper "reserve margin").
Thinking about the issue in these terms, it ought to be readily
comprehended that there is no such thing as "excess capacity" in
perfectly competitive markets. Competitive forces, in
theory at least, will always work to clear markets regardless
of the level of available capacity. There are limitations
to this, of course, but the point is generally valid. We
do recognize that excess capacity ("unused" or "underutilized")
can exist in a macroanalytic context but only as a result
of a failure of markets to clear. In very general terms, then,
excess capacity arises only when markets fail to
establish a market-clearing price.

Given this definition, our attention is turned toward
an inquiry into the conditions under which markets would
fail to clear. In doing so, it is not necessary to rehearse
the voluminous literature on market failure because the kind
in which we are interested is not one that generally arises
in unregulated markets. The "market failure" which concerns
us is hypothetic. It is a condition under which markets
would fail to clear if firms behaved in the postulated manner.
some contribution to overhead, whereas not producing does not. Only if the price consumers are willing to pay does not cover the variable costs of production will the firm cease operation. The point of this rather fundamental excursion into elementary microeconomics is that to clear the market the firm must forge recovery of at least a portion of its fixed costs, that is, its capital costs (including depreciation).

The foregoing analysis is price theory as it applies to the short run. What ought to be the long-run reaction of a firm facing consumers not willing to pay average total costs at the present scale of production? Here, too, the theoretical implications are straightforward. Under the circumstances postulated, the firm should seek to reduce its overhead costs. It may do this by reducing the scale of investment—shutting down plants. For example—or by gradual disinvestment (not replacing plant as it depreciates). At some lower level of investment its overhead costs will prove more manageable (recoverable) in prices that consumers are willing to pay. The optimal scale of production, of course, is one at which average total costs are equal to marginal costs. At this level of production, a price equal to marginal costs will fully recover overhead costs as well.

Before considering the implications of the foregoing analysis, a few comments are in order regarding what might seem to be a fundamental objection. The conclusion just obtained presumes, of course, an upward rising supply curve—decreasing returns to scale. While this is considered plausible for firms in competitive unregulated markets, the natural monopoly theory of regulation presumes that regulated firms face increasing returns to scale. There is a growing body of evidence, however, that challenges this view, at least as far as electric generation is concerned. Whether the evidence is sufficient to justify bulk power deregulation is another question entirely. While leaving that issue aside, I cannot help but remark in passing that I fail to see how it would work, unless the generation function is separated from the regulated firm entirely. It would seem to be the worst of possible worlds to "deregulate" bulk power transactions among firms at the wholesale level while allowing generation plant to remain in the ratebase at the retail level. Be that as it may, the objection that electric power production is a natural monopoly is no longer an obvious one.

Policy Implications

I have offered as a general definition of excess capacity the failure of a market to clear. Hypothetically, markets would fail to clear if firms sought to price their output so as to recover the total cost of production when consumers' willingness to pay is in fact less. Only if the firm forces a portion of the recovery of its fixed costs will it find a market for all its available output. The excess capacity problem in the electric utility industry can be profitably evaluated in this light. What price would be required to "clear" the market? The answer, clearly, is something less than the price that comes from a traditional ratebase approach. It seems evident that, in order to clear the market, prices will have to be set so as to force recovery of at least a portion of fixed costs.

One can look at the various pragmatic approaches to rate making treatment of excess capacity as ad hoc efforts to accomplish something of this nature. Whether through a ratebase adjustment, disallowance of a component of the capitalized carrying cost, or imputation of hypothetical revenues from off-system sales, the effect on the firm is ultimately the same: failure to recover fully its capital costs. The problem with each of these is the lack of a direct connection between the level of costs disallowed and the reduction actually necessary to clear the market.

In theory, at least, a preferable approach would be some form of experimental pricing which seeks to clear the market. Given the current level of excess capacity in this country, it appears that some room remains for reducing prices to consumers. As a practical matter, the problems with this approach certainly suggest that any implementation proceed with caution. Prices should not be cut so low as to stimulate demand too rapidly, also there is the danger of stimulating so much growth that a new round of construction would be required. The object is to clear the market at the current excess, not stimulate demand through "loss-leader" pricing such that consumers would be jolted when new capacity required to meet new demand comes on line. Furthermore, regulated firms supplying service in monopoly markets do not enjoy the opportunity to learn from the behavior of their competitors. This inability makes it difficult to uncover the market clearing prices; the magic of Adam Smith's Invisible Hand is simply lacking. Perhaps a satisfactory heuristic would be to forgo any price increases as long as the excess capacity remains. This obviates the need to determine exactly how much to cut prices. Consumer demand would simply be allowed to "grow into" the current level of capacity.

Another alternative is suggested by the remarks made above regarding proposals advanced to deregulate bulk power production. Done correctly, this would assure that the desired result, but the structural changes required would be radical. Generation would have to be separated totally from transmission and distribution. Losing the regulatory umbrella that allows regulated firms to subsidize generation through cost-plus pricing would, presumably, subject the industry to tremendous competitive pressures. Prices would
tend to reflect willingness to pay rather than cost of production, and high cost producers would likely not recover their total cost of production. Similar to airlines which could not compete at competitive market prices, some generation utilities would lose money, and a few would probably go bankrupt. The market, rather than the regulator, would determine who fails to recover full capital costs and by how much.

There is an attractive topic to all this, but there is a serious drawback. The theory of perfect competition is a static model which ignores the time it takes to shift from the short-run to the long-run. In the electric power industry, that shift is determined by the planning horizon for new capacity. The capital value of assets tied up during the construction process has been increasing relative to the capital value of assets presently in place. Although there may no longer be any technological economies of scale, the minimum efficient scale of firm operation in terms of the capital required has increased substantially. The largest barrier to designing an optimal industry structure for a deregulated electric bulk power market will be determining the appropriate scale of the industry, as well as relevant geographical markets. Unless this problem is satisfactorily addressed and resolved, I do not foresee deregulation as a workable concept.

Practically, then, I envision only two general options. The first is to continue to rely on legalistic approaches. The second is to tackle the problem structurally by experimenting with prices in an effort to clear the market. The first is clearly the more conservative approach to judge by its application in practice. Do nothing, that is, to insist on full cost-plus pricing as embodied in traditional ratebase regulation, is so conservative, however, as to be reactionary. The history of the industry over the past decade is a prelude to the future if rates are set to recover the total cost of service. Consumers will react by curtailing consumption even more, creating a never-ending spiral. The excess capacity situation will get worse, not better. If regulation does not pay full heed to the implications for policy of the competitive model, consumers will revolt. The last decade has given us a taste of what they can do if we ignore their willingness to pay. It is better to recognize their sovereignty.

Notes

1. For early arguments in favor of "fair value" regulation based on allocative efficiency considerations, see Brown (1925) and Trowel (1949, 1950). These authors did not argue that fair value was necessary to compensate investors for the effect of inflation on the value of their investment, but that it was required to allocate resources efficiently. These arguments foreshadowed much of the recent interest in "marginal cost."

2. Inflation after both world wars and the Korean War created considerable pressure for the fair value approach to ratebase valuation. Original cost remained a viable alternative, however. Current challenges to original cost valuation are of an entirely different character.

3. An excellent journalistic account of how things were changing toward the end of the 1970s appears under the title "A Dark Future for Utilities." Business Week, May 28, 1979, pp. 108ff. Here are two choice quotes from the article illustrating industry attitudes toward price elasticity: ""Price is a much more allocative tool then previously was thought," says Irwin M. Stelzer, President of National Economic Research Associates (NERA)," and "one company that misread the future is Dallas-based Texas Utilities Co. 'None of us predicted correctly what the price elasticity (of demand) for construction electricity would be,' concludes Chairman T. C. Austin. The company is now saddled with a capacity reserve margin of 48%, nearly twice that regarded as prudent for the country as a whole.' Not everyone in the industry is so candid.

4. The two oil embargoes of the 1970s were frequently blamed for much of the industry's woes. While these were indeed shocks of a random or exogenous character, they hardly do nothing, that is, to insist on full cost-plus pricing as embodied in traditional ratebase regulation, is so conservative, however, as to be reactionary. The history of the industry over the past decade is a prelude to the future if rates are set to recover the total cost of service. Consumers will react by curtailing consumption even more, creating a never-ending spiral. The excess capacity situation will get worse, not better. If regulation does not pay full heed to the implications for policy of the competitive model, consumers will revolt. The last decade has given us a taste of what they can do if we ignore their willingness to pay. It is better to recognize their sovereignty.

5. For interesting speculations along this line, see Rotch (1983), Hawken (1983), and Toffler (1983).

6. While the literature on economies of scale in electric power generation is mixed, the weight of the evidence appears to indicate that unit economies of scale are exhausted at unit sizes much beyond 400-500 Mw. A good but incomplete survey of this literature can be found in Joskow and Schmalensee (1983, chapter 5). Their survey is not complete, however. Ford and Flain (1979) argue that when diseconomies associated with unit unavailability are considered, the optimal unit size may only be 200-300 Mw.
7. For an interesting structural and institutional analysis of coal markets, see Stobough and Teng (1978, Chapter 4). Certainly, it must be conceded that rising delivered prices for coal owe significantly to coal transportation rate hikes. But "delivered" prices have escalated significantly even at company-owned mine-mouth plants.

8. The fitted equation is of the form:

\[ \ln (D(t)) = -2.95274 + .833095 \ln (Y(t-1)) - 1.09917 \ln (P(t)) + .347903 \ln (Y(t)), \]

where \( R^2 = .991041, F = 663.693; D.W. = 2.45422; \) \( \hat{\sigma}(t) \) is the annual peak demand per customer in year \( t \); \( P(t) \) is the average real cost of electricity (average cost deflated by the GDP implicit price deflator) in year \( t \); and \( Y(t) \) is real GDP per customer in year \( t \). The coefficients for \( \ln (P(t)) \) and \( \ln (Y(t)) \) are short-run (one-year) price and income elasticities, respectively, and have t-statistics of 2.759 and 1.707, respectively, for 15 degrees of freedom. (The equation was fitted using annual data for 1931-1962.) Long-run price and income elasticities are derived by dividing the short-run elasticities by one minus the coefficient of lagged demand variable:

\[ LR \text{ price elasticity} = -1.09917/(1-.833095) \]
\[ = -6.61560 \]
\[ LR \text{ income elasticity} = .347903/(1-.833095) \]
\[ = 2.08497. \]

While not implausible, these results suggest that demand is somewhat less elastic with respect to price and more elastic with respect to income than has typically been reported in the literature. (For a survey, see Electric Utility Rate Design Study (1977, pp. 62-91).) The lower price elasticity may reflect the fact that peak demand rather than bulk sales was employed as the consumption variable, while the higher income elasticity may reflect the influence of the inclusion of data from the more recent period, years of very poor economic performance. In any event, these differences make the projections reported in the text of the paper more liberal than they might otherwise be.

9. This is captured in the Koyck model by the distinction between short-run and long-run elasticities. Based on the equation parameters reported in note 8, only 61 percent of the long-run effect of price or income would be played out after five years. Since the directions of change in prices and incomes during the late 1970s were adverse with respect to future consumption, the model implies that future consumption will continue to be affected by these changes for some time. Conceptually, rising prices and stagnating incomes set in motion various forms of substitution and conservation, the effect of which will continue to be felt for some time.

10. See the 34th Annual Electric Utility Industry Forecast, Electrical World, September 1983, pp. 55-62. Specifically, the projections reported here attempt to approximate L&M's with respect to customer growth, prices, and incomes. These are the principal structural determinants of total demand in the methodology employed here.


12. A notable example of this is a study performed by Energy Management Associates (1982) for Middle South Utilities. This study purports to demonstrate cost justification for reserve margins of up to 71 percent. At least two implausible assumptions account for this fantastic result. The first was that 1,950 MW of new coal capacity could be brought on line in 1987 at a normal installed cost of $1,019 per kw, and another 1,950 MW (companion units) in 1989 at an installed cost of $842 per kw in nominal dollars. The second implausible assumption is that generation from these new units would displace oil generation at prices escalating to more than $60 per barrel by 1990 and more than $100 per barrel by 2000. Even at the time this was an implausible assumption, not because of the projected oil price increases, but because the economics of displacement were not favorable when the amount to be displaced and the true capital cost of new capacity were both taken into consideration.

13. Recent studies by Georgia Power Company intended to develop an appropriate cost planning reserve margin produced a minimum of about 20 percent (assuming the existence of emergency priorities) after allowing for the higher unavailability of new large units on the system. This result is probably not unrepresentative of what other studies would show and suggests that an increase in the planning reserve margin of 33 percent, that is, from 15 percent reserves to 20 percent, is more than adequate to allow for the lower system reliability associated with larger unit size. See Dahlberg (1983).

15. Considerable evidence points to reliability problems associated with attempting to operate high-pressure coal-fired steam turbines in a cyclic mode of operation. See, for example, EPRI [1979]. A prudent system planner would restrict the installation of baseload capacity on a system to a level sufficient to equal the system's average load. Since average load is sufficiently above minimum load on most systems, this would supply enough redundant baseload capacity to meet normal requirements for maintenance and unscheduled outages. Capacity above average load can be more economically served by intermediate or peaking capacity. Baseload capacity serving this portion of the load will not operate enough to justify the higher capital costs of baseload capacity and will impose cost penalties because of the reliability problems discussed above. In point of fact, however, baseload demands have been growing more slowly than intermediate and peaking loads, while almost all new capacity now coming on line or projected to come on line is baseload capacity. The nation's generating mix is becoming increasingly suboptimal.


18. In Re Niagara Mohawk Power Corp., Cases 27741, et al., Opinion No. 81-5, March 15, 1981, excess capacity was defined as that in excess of the 18 percent reserve margin required by the New York Power Pool. The North Dakota Public Service Commission has also used power pool reserve obligations as the measure of adequate capacity. See Re Otter Tail Power Co., [1981], 44 PUB 4th 219 and Re Montana-Dakota Utilities [1981], 44 PUB 4th 249.


20. Re Northern States Power, Memorandum Decision Civ. 82-6, in Circuit Court, Sixth Judicial Circuit, State of South Dakota. The cited cases were San Diego Land & Town Company v. Jasper, 189 U.S. 439 [1903] and Compton & L. Turnpike Road Co. v. Sanford, 164 U.S. 578 [1897].

21. The application of the used and useful principle to excess capacity issues has a long history in regulation. In addition to the Supreme Court cases and the Pennsylvania case cited in note 20, see Ferm Lake Co. v. Kentucky Pub. Service Commission [1967], 44 PUB 3rd 354, 357-359, 361, 357 W23 314; Re Southern New England Telephone Co. [1962], 42 PUB 3rd 210; North Carolina ex rel. Utilities Commission v. General Telephone Co. of the Southwest [1972], 291 NC 178, 291 S2d 106; Southwestern Bell Telephone Co. v. Public Service Commission [1970], 39 S2d 137, 137 So. 2d 30; Re Wisconsin Telephone [1939], 6 PUB 499; and North Dakota Public Service Commission v. Montana-Dakota Utilities [1959], 29 PUB 4th 269, 290 M25 140.

22. The concept of prudence may also be extended to consider managerial responsibility throughout the planning process. A decision to build may be prudent when made, but that does not mean that managerial responsibility thereby ceases.

23. If circumstances change, the prudent decision may be to curtail or cancel construction. Management remains responsible throughout the planning process, not just at its inception. Even the granting of a site permit or a certificate of convenience and necessity by a regulatory agency does not grant management immunity from later inquiries regarding the prudence of its later actions. See Re Iowa Power & Light Co., Docket Nos. HPR-78-3B, HPR-79-30, and HPR-80-20, February 15, 1981, Re Iowa Power & Light Co. [1982], 46 PUB 4th 339.

24. If the risk of excess capacity is not to be borne by the firm and its shareholders, we may justifiably ask for what they are being compensated. If all excess capacity "prudently incurred" were to remain in the ratebase, one could justifiably argue that shareholders would be allowed to continue to accrue APEIC. This greatly mitigated the ultimate effect on investors of the commission's decision.

25. For example, see Re Otter Tail Power Co., 44 PUR 4th 219 and Re Metropolitan Utilities Co. (1981), 44 PUR 4th 249.

26. Re Public Service Co. of New Mexico, Case No. 1804.

27. See, for example, Re Niagara Mohawk Power Corp., Cases 27741, et al., Opinion No. 81-5, March 12, 1981; and Re Madison Gas & Electric Co. (1980), 34 PUR 4th 566.

28. The revenue adjustment in the Madison Gas & Electric case, 34 PUR 4th 569, was subsequently set aside by the Wisconsin Supreme Court because the commission applied neither the used and useful nor prudent investment tests, but merely assumed (without sufficient evidence) that the excess would be sold. A jurisdictional allocation would necessarily imply that nonjurisdictional plant is not required (used or useful) to serve jurisdictional customers.

29. Not only are such firms failing to recover fixed costs, but also competitive market rates are not even enough to recover the variable costs of production. See "Oil Drillers, Suppliers See Uncertain '86," Wall Street Journal, December 21, 1983, p. 27, 46.

30. For example, the Rhode Island commission recently approved a controversial rate (discount plan proposed by Narragansett Electric that provides a 20 percent reduction for new industrial customers and a similar cut for existing industries on incremental electricity use exceeding 110 percent of 1981 kwh levels. Narragansett successfully demonstrated to the commission that the cost of producing additional power was below average cost. Even discounted, the new consumption is expected to produce revenues in excess of incremental cost and thus provide a contribution to overhead. Consumer groups argued that the plan was discriminatory. They are correct. Although other rate classes are not "burdened" by the (industrial) discount, to offer a discount to industrial users and not to residential users is clearly a form of "third degree" price discrimination. While industrial use may be more elastic and as a class will generate more revenues for a given level of discount, the incremental cost to serve residential users is also below average cost when a utility has excess capacity. The use of experimental pricing to clear the market should not constitute an excuse to engage in discriminatory pricing. Applying Stigler's (1952, p. 214) definition of price discrimination (the sale of various products at prices not proportional to their marginal cost) would provide a foundation for developing rate discounts that treat all classes equitably.

31. This may happen anyway. Because of the sheer magnitude of the problems caused by excess capacity and costly plant, some utilities will fail to recover full capital costs no matter how hard local regulators work to bail them out, and we should not be surprised if one or more large investor-owned utility is forced into receivership.

32. For an excellent survey of the obstacles to deregulation, see Jostok and Schmalschen (1983). As good as it is, this work is not without its flaws. One shortcoming is the failure to emphasize that true deregulation implies not only massive structural and institutional change, but also total elimination of rate support of any kind. The latter requirement would create a Brave New World quite unlike that of any ever experienced by utility executives, but now familiar to many formerly well-paid airline executives (and airline pilots) who miss the good old days before deregulation.

References


THE REGULATORY CHALLENGES OF MAJOR PLANT ADDITIONS OR RATE SHOCK AND OTHER REGULATORY HEADACHES

William M. Galiavan and Bruce T. Smith

Rate shock—the mere phrase evokes the image of residential customers opening their electric bills as their house shakes off its foundation and collapses around them. While the image is a bit extreme, the reality of rate shock—the substantial rate increase caused by the operation of expensive capacity additions, generally nuclear units—is definitely with us. Rate increases of up to 50 percent for some utilities are possible as the power plants currently under construction are completed and placed in the ratebase. Just as fuel cost increases caused rate shock in the 1970s, plant additions will be the cause in the 1980s. Rate shock is a serious problem receiving serious attention from utilities, regulators, elected officials, ratepayers, and the investment community. Balancing the interests of these groups will be a difficult task. Unfortunately, there is no simple solution.

PG&E’s nuclear plants on the central California coast, Diablo Canyon Units 1 and 2, are virtually complete and will begin commercial operation in the next year. By way of background, with implementation of pending rate relief, PG&E’s Electric Department will have revenues in 1984 of $4.5 billion on a ratebase of $8.5 billion. The two units at Diablo Canyon will increase electric ratebase by nearly $4 billion, or more than 70 percent. Fortunately, since Diablo Canyon will displace generation from fossil-fired plants, the net revenue increase with the operation of the Diablo Canyon units will
be only $500 million, or 12 percent. "Only" is a relative term—a 12 percent revenue increase compares to a 70 percent ratebase increase.

Although the percentage rate increase for Diablo Canyon will be mild compared to that for other utilities' new plants, the magnitude of the dollar amount is staggering. Accordingly, the rate shock issue is just as relevant for PG&E as for other companies. Indeed, the California Public Utilities Commission, in its September 1982 decision regarding Southern California Edison's San Onofre Nuclear Generating Station Units 2 and 3, ordered that future hearings consider "whether alternative retekancing treatments involving deferred capital recovery can or should be adopted by this Commission." We are thus reviewing the various phase-in proposals around the country and have begun analysis of several of them in anticipation of the Diablo Canyon rate application.

Why Is This Happening?

From the point of view of retekancing mechanics, the source of rate shock has always been with us. New plants are placed in the ratebase at historical cost, and revenues are increased to cover costs, including depreciation and return on the increased ratebase. Revenue requirements decline over time as the depreciation reserve builds up and the ratebase is reduced, causing the return component of revenue requirement to decline over the life of the plant, typically thirty to forty years. Historically, these rate shocks, or perhaps more properly "revenue shocks," were masked by two factors. First, economies of scale and technological improvements in the design and construction of what were then new generating facilities meant that the revenue shock per kilowatt of capacity was lower for each successive generation of plant. Second, loan and sales growth produced increased revenues so that individual customers' bills were not increased.

Unfortunately, these mitigating situations do not exist today. The scale of plants seems to have topped out at roughly 1,000 Mw per unit. The costs of social and regulatory requirements—such as equipment to control air and water emissions from fossil plants, safety and seismic equipment in nuclear plants, the additional protection costs to obtain various permits—and general price inflation have made new capacity additions more and more expensive. When capacity is added in large increments, it creates an increasing, jagged, sawtoothed curve of ratebase additions and revenue requirements. Needless to say, revenues from increases in sales in the short term are insufficient to cover increases in revenue requirements. When capacity is added in small increments, the revenue requirements increase over time, and while the results are essentially the same, there is no perceived rate shock.

We imagine that any regulator or utility executive would expect ratepayers to protest a rate increase of 50 percent per plant additions. However, in most areas of the country there have been large rate increases in the past, and there will be more in the future, to recover the increased costs of providing electric service. These rate increases have recovered the increases associated not only with fuel but also with labor, materials, and additional plant (facilities) required to generate, transmit, and distribute electricity. In some instances the rate increase associated with a major plant addition is not out of line with the recent trend of rate changes, but rate shock is relative. One never hears complaints about the shock associated with large rate decreases. For example, in 1962 and 1963 the moderation of fossil fuel prices and the increased availability of hydroelectric generation caused by two consecutive wet winters allowed PG&E to decrease its electric rates by $1.3 billion, or 25 percent. This is more than twice the rate effect which will be caused by adding Diablo Canyon Units 1 and 2 to PG&E's ratebase.

What Can Be Done?

Utilities and regulators are investigating accounting and retekancing mechanisms aimed at ameliorating the immediate problem. In addition, we believe they must take steps now to reduce the magnitude of the rate increases for future plants.

Since most companies and jurisdictions will face rate increases substantially in excess of past rate changes, phase-in proposals of several types have been offered. These fall into three categories: "what if," "not now," and "economic," which includes "economic depreciation" and "economic valuation."

"What If" Proposals

The "what if" category is included the scheduled rate increases proposed for Public Service of Indiana's Marble Hill plant and the replacement plant concept proposed for the Grand Gulf plant owned by Middle South Utilities. For the Marble Hill units, which are scheduled for commercial operation in 1986 and 1988, the utility proposed a "rate control" plan consisting of six annual 8 percent rate increases from 1984 to 1989 in lieu of all rate increases except fuel cost adjustments. This would clearly ease the plant into rates and reduce rate shock by implicitly recovering some plant-related costs before the units enter commercial operation. However, the public service commission suspended consideration of this proposal until after a task force appointed...
by the governor could study the situation. The governor’s charge to the task force includes the directive that customers not be required to pay for Marble Hills before it is placed in service. For Grand Gulf, New Orleans Public Service and Louisiana Power and Light are proposing that the wholesale tariff from Middle South price the output of Grand Gulf at the costs—fixed and variable—of a theoretical fossil-fueled plant. Assuming an oil price of $30.00 per barrel and annual price increases of 8 percent, the costs of the “what if” plant would be less than Grand Gulf for four years, which would be made up by the higher costs of the proxy plant in the following five years. For New Orleans residential customers, the rate increase in the first year would be reduced from 94 percent under traditional ratemaking to 56 percent with the company’s plan.

The proposal for Marble Hills, by beginning revenue collection before plant operation, would lead to the creation of a deferred “liability—equity owed to ratemakers—which would be applied (in essence, repaid to ratemakers) to make up for the revenue shortfall after the units go on line but before the scheduled rate increases catch up with the revenue requirement. In contrast, in the Grand Gulf plan, a deferred asset is created since the ratemakers “owe” the utility more than is collected in the first four years. These funds will be recovered from ratemakers in the succeeding five years as the revenue requirements of the proxy plant exceed those for Grand Gulf.

The “negative SWIP” proposal for Long Island Lighting’s Shoreham nuclear plant is somewhat similar to the Marble Hills plan. The benefits of having had a portion of Shoreham’s costs in the ratebase prior to commercial operation will be returned to ratemakers through reduced rates in the first three to five years after commercial operation.

"Not Now" Proposals

The “not now” proposals have an effect similar to that of the Grand Gulf plan—deferring recovery of a portion of the plant’s costs—but the deferral is not based on the costs of a replacement plant. For example, low—illinois Gas and Electric has suggested that a portion of equity return and depreciation of the 850 Mw coal—fueled Lousia plant be deferred for three years and then recovered over the next five. The deferral amounts were chosen with an eye to the resulting rate increases. Thus, a deferred asset will be created over three years and then recovered from ratemakers over the following five years. The Louisiana phase—in will be accomplished through an automatic adjustment clause.

"Economic" Proposals

Two “economic” phase—in proposals have also been made.
Effects on Utilities and Investors

All the phase-in proposals accomplish to one degree or another their primary goal: to reduce the rate effect on customers of large plant additions. However, no discussion of these proposals can be complete without considering their effect on the utilities. Nearly all the phase-in proposals discussed here will create a deferred asset to be recovered from future ratepayers. (The exceptions are Marble Hills, where Public Service of Indiana would get a head start on collecting revenues, essentially creating a deferred liability rather than a deferred asset; and LILCO’s plan, which, while it may not create a deferred asset, will nonetheless cause revenues after the third year to be higher than they otherwise would have been.)

While the creation of the deferred asset is not in itself objectionable, there are several negative effects. First, regulators must recognize and acknowledge, as will utilities and investors, that the accrual of return after commercial operation creeps up as seen in “fuzzy money” paper earnings as does AFUDC. Investors will thus have the burden of the financing costs of new facilities after commercial operation as well as during construction. Second, as current income is reduced, so is cash flow. Although cash will no longer be required to fund construction of the plant, cash flow from operations will not increase, and financial indicators, such as coverage ratios, will continue to be depressed. Third, as the depressed asset grows, the capital invested in the utility becomes more concentrated in one asset, increasing the utility’s risk profile.

Fourth, the investor’s perceptions of the value of the deferred asset are a function of the quality of regulation. The regulators must commit themselves to see any phase-in plan through to its originally stated conclusion. Specifically, when the cross-over point is reached, amortization of the deferred asset must begin, and rates must be increased at that time. (low-Illinois Gas and Electric proposes an automatic adjustment which will operate without future commission action to provide the necessary assurances of recovery to satisfy the requirements of generally accepted accounting principles and to be acceptable to the financial community. Regulators will also have to face the issue of allowing current return on the deferred asset or deferring the return and increasing the amount of the deferred asset.

Fifth, the deferred asset, which may become greater than the original cost of the plant, may not qualify as collateral under a utility’s bond indenture. In order to make up a cash flow deficiency, the utility would have to turn to equity financing, thus increasing the equity-capital ratio, the rate of return, and ultimately ratepayer costs. Just as the utility will be burdened with this deferred asset, so will its ratepayers. The return on the deferral over its lifetime—whether eight years or thirty years—will increase the amount of revenue collected from ratepayers. Although a judicious choice of discount rate will show that the present values of the revenue streams are equal and that ratepayers are indifferent (or perhaps would even favor deferring payments), regulators will nonetheless be committing ratepayers to higher bills in the future and to paying more over the life of a project than under conventional ratemaking.

A Critical Look at Trended Ratebase

Given these concerns, let us return to the trended ratebase proposal and examine its effect on investors. Under this proposal, the amount of return for investors will be limited to the noninterest-only real return. For example, if the rate of return authorized by the regulators is 13 percent and inflation is 7 percent, the real rate of return is 6 percent (that is, 13 percent minus 7 percent). The question is whether investors will settle for only the real rate of return. This is doubtful. No lenders require only part of their interest charges to be repaid; all the interest charges must be paid when due. Indeed, with a target payout ratio of 60 percent for common stock dividends (that is, 60 percent of earnings available for common is paid out as dividends), a utility with a 12 percent rate of return and typical capital structure will be required to use 10 percent of the 13 percent to pay interest, preferred equity dividends, and common equity dividends—an amount clearly in excess of the 6 percent real rate of return. Only if no common equity dividends were paid would the income be sufficient to cover the fixed financing costs.

Theoretically, it is easy to say that common equity holders will be willing to take their return in capital appreciation. However, that assumption contradicts the generally accepted profile of utility stockholders as being very conservative and primarily concerned with current dividend yield, not capital growth. Capital appreciation would be available to the stockholders by this mechanism: The amount of asset appreciation would be included in income each year and added to retained earnings, thus increasing the book value of common equity shares. For stockholders to realize this capital gain, they would have to sell stock at a price no less than book value. In order for stockholders to come out even if granted adequate current income, they will need a guarantee that authorized returns will be high enough to maintain a market price of the stock equal to book value. Unfortunately, the recent history of the performance of utility stocks indicates that regulators have been unable or unwilling to
provide a reasonable opportunity for market values to equal book values; there is little reason to believe that trend will change.

Can Rate Shock Be Prevented?

Although it is too late to prevent the impending rate shock of plants coming on line in the near future, both regulators and utilities must investigate more flexible options for the financing and rate-making of future capacity additions and replacements. As opposed to the decades of the 1950s and 1960s, the costs of serving customer and load growth, whether by nuclear or fossil generation (yes, even cogeneration, windmills, and so forth), if priced at avoided costs, will be greater than the revenues those customers and loads would provide at present rates. Rate shock will accompany each new large plant addition, regardless of fuel source; the string, permitting, and environmental costs of fossil-fired generation will see to that.

In weighing the burdens and benefits between investor and ratepayers, regulators have refrained from the use of different vintages of ratepayers. Indeed, the most frequently used argument against placing CHP in the ratebase is that today’s customers should not pay the carrying costs for the plants that will serve tomorrow’s customers. (Although it seems certain that when buying a 1964 Chevrolet one is picking up a portion of the financing cost of the assembly plant being constructed to build the 1966 models.) We must now recognize that vintages of investors should not be unduly burdened by the rate impacts of vintages of ratepayers.

Financing of future plants may have to identify specific vintages of bondholders through the use of serial and zero coupon bonds and various derivatives. These instruments would not require interest payments over their lives. Rather, investors would receive their cash at the time the bond’s maturity. A bond redeemed in thirty years for $1,000, for example, would be sold today at $57.30 for a yield of 10 percent. Staggered maturities would be used to coincide with a predetermined capital recovery schedule.

Deferral of dividends to equity investors, however, is another matter. Cash returns to each vintage of such investors, who buy utility stocks primarily for dividend yield, must continue to be assured during both the construction and the operation of large generating units. If this cash return is not maintained, equity investors will require a substantial premium in the cost of equity.

Other Regulatory Challenges

The discussion in public forums of the rate increases associated with new plant additions is general, and the potential for rate shock in particular, has focused public attention on the competence of utility management. Critics contend that management incompetence brought about the situation of expensive capacity additions, that management has not acted reasonably and prudently in the construction of these plants.

The review of management action places regulators in the admittedly uncomfortable role of second guessing management decisions. Unfortunately, there does not seem to be an acceptable standard as to what constitutes reasonable and prudent behavior. These are relative, not absolute, concepts. Reasonable and prudent management may still produce results which deviate from the original plan, cost increases and schedule delays are not proof of imprudent and unreasonable management. Presumably, if a utility were found to have been unreasonable and imprudent, the consequence would be to have all of plant investment disallowed. Any such disallowance would be charged against the equity investors. However, as New York Public Service Commission ALJ Frank S. Robinson pointed out in his recommended decision on the rate-making for the early retirement of Con Ed’s Indian Point Unit I, "we could not attempt to shift a major part of a utility’s cost to shareholders and hope to make it stick. The market simply wouldn’t let us, such a utility’s cost of capital would go through the roof, and what we take away with one hand we would have to give back with the other. Over the long-term, the users of electricity must pay, one way or the other, substantially all the costs involved in providing them with power." One can see how this could come about by noting that a large disallowance of the costs of a new facility, especially one that represents a major portion of invested capital (as is likely the case with a utility facing major rate shock), could have a disastrous effect on capital structure, dropping the equity ratio by as much as 10 percentage points. When the resulting increase in capital costs is reflected in rates, it can easily offset any savings due to the reduced plant costs.

Conclusion

The rate shock which will result as plants currently under construction are completed and placed in the ratebase, must continue to be assured during both the construction and the operation of large generating units. In this cash return is not maintained, equity investors will require a substantial premium in the cost of equity.
burdens will only increase ratepayer costs later on.

For the future, if CWIP is placed in the ratebase, an automatic phase-in mechanism will be in place, and rate shock will be substantially reduced. Perhaps if the issues of equity between vintages of customers and vintages of investors are considered together, we will find a solution which causes minimum discomfort to all parties, possibly allowing a portion of CWIP in the ratebase during construction and deferring a portion of required return until after commercial operation.

ECONOMIC AND FINANCIAL IMPLICATIONS OF ALTERNATIVE RATEMAKING TREATMENTS OF PLANT CANCELLATIONS, ABANDONMENTS, AND PREMATURE RETIREMENTS

Richard J. Lurito and Bruce M. Louiselle

One of the most interesting and perhaps unique aspects of public utility ratemaking is the extent to which it requires a multidisciplinary analysis of a microcosm of the economy—the public utility. In the nonregulated sector of our economy, the decision making of a firm is focused, by its nature, on advancing the parochial interests of that firm. In the regulated sector, decision making by regulators must focus on and consider the diverse effects of various alternatives to treating an issue.

A typical rate case decision will affect not only the utility's customers and investors in a direct way, but also others in indirect ways. A decision will affect the standard of living of the customers of the utility as well as other citizens in the geographical area served by the utility. It will affect the employment opportunities both today and in the future in that area. It will affect business activity, and it will affect the taxes received by the various taxing authorities. Finally, decisions by one regulatory commission can have a significant influence on the costs incurred by other utilities in other jurisdictions and, hence, on the rates paid by those utilities' customers.

In more technical economic terms, a rate case decision affects both the supply of and demand for the regulated product
as well as the supply of and demand for the factors of production of not only the utility directly involved but also other business enterprises. It also affects the fiscal policy of the governing units. It is in this sense that the regulation of a utility and its effects mirror the overall economy and the decisions that affect it.

Besides being a microcosm of the economy, the regulation of a public utility requires the input of many disciplines: economics, finance, accounting, engineering, and law. While the resolution of an issue may rely primarily on one discipline, an analysis of most issues requires an understanding of more than one.

It can be seen that an analysis of an issue from just one perspective will often lead to more questions than answers. The topic at hand, alternative ratemaking treatments of unused and unuseful plant, is such an issue. The focus of this paper is limited to the economic and financial implications of those alternatives. Consequently, this restricted focus may produce more questions than answers.

Definition of the Issue

Among the rights of a public utility is the opportunity to earn a fair return on and on the capital investment that is necessary to provide the regulated service. The capital investment is typically quantified in terms of the rate base. While the definition of the rate base can and does vary among jurisdictions, the differences are generally not relevant to the issue at hand. As is well known, the rate base consists primarily of net plant in service. In addition, in most jurisdictions another important element is construction work in progress (CWIP). To be included in the rate base, it is generally necessary that the item be both used and useful. What constitutes "used and useful" is one of the questions that will not be answered since it is beyond the scope of this paper. Suffice it to say that to be considered used and useful, a necessary condition is that the item (plant) is or will be needed under prudent management to meet the public utility's obligation to provide safe and adequate service to those willing to pay for it. Obviously, if that item (and the focus in this paper) is on plant items not now and will not be used in the future to provide service, it does not meet the necessary but perhaps not sufficient condition for rate base inclusion.

Plant that exists but is not used and useful can acquire that negative status in one of two ways: (1) The plant can be retired prior to the end of its technical life; (2) it can be abandoned prior to its ever being used. It should be noted that the terms plant cancellation and abandonment are considered synonymous and are to be differentiated from premature retirements. Plant cancellation could be defined as a projected stoppage prior to the start of construction (when only preliminary survey and licensing costs have been incurred). A plant abandonment could be defined as project stoppage after actual construction has begun (when costs such as excavating and bricks and mortar have also been incurred). The distinction, however, is not relevant.

In sum, it is abandonment and premature retirement which trigger the need for some special regulatory treatment. It is the alternative ratemaking treatments to these events and their financial and economic implications that are the subject of this paper.

It is our conclusion that the alternative treatments available to regulation have different long-run economic and financial implications and that regulators should have a knowledge of what they are and accept the responsibility to see them through over the long term once a particular treatment has been chosen.

The Ratemaking Alternatives

It will be recalled that one of the rights of a public utility is the opportunity to earn a fair return on and on the capital necessary to provide service. In the case of either an abandonment or a premature retirement, capital has been invested; hence, the issue of the return of and on this capital is raised. The return of capital is commonly known as depreciation and under normal circumstances is included in the revenue requirement used to set rates. The return on capital is also normally a component of the revenue requirement and is equal to the allowed rate of return on the rate base. When the capital is invested in plant that is in service the return of capital is called depreciation; when that plant is abandoned or otherwise retired, it is called amortization.

Consequently, when a plant is abandoned or retired prematurely, there are two issues on which regulation must focus: (1) the extent to which the return of capital, amortization, is to be reflected in rates and (2) the extent to which the return on capital, rate base treatment, is allowed. The various treatments, therefore, turn on the extent to which return allowances are permitted. The treatments that regulation can implement could be summarized as follows, going from the least to the most onerous on investors: (1) Allow for the full amortization of all the costs incurred and include the unamortized balance, net of taxes, in the rate base; (2) allow for the full amortization of all the costs incurred but do not include the unamortized balance from the rate base; (3) allow for the amortization of some but not all of the costs incurred, but exclude the unamortized balance from the rate base; (4) do not allow either amortization or rate base treatment but allow a higher than market-justified return
on equity; and (5) permit no recovery on or of the invested capital at issue.

While this list of alternatives is not exhaustive, it does represent the gauntlet of rational alternatives. Obviously, other variations, both rational and irrational, have been implemented.

Before discussing these alternatives and their financial implications, it would be useful to comment briefly on premature retirements. There are three types. The first two are those undertaken to lower costs and those involuntarily imposed by outside forces. Examples would be a referendum requiring the shut-down of a nuclear facility or a problem with the operation of a plant that renders it useless. The third type is retirements necessitated by unplanned or unforeseen events. A plant which physically deteriorates faster than anticipated, resulting in retirement, would be an example. The second and third types of premature retirements are of primary interest here, because regulation is called on to treat, in some fashion, the higher costs that result. In the case of the third type, most often the unrecovered capital costs are relatively minor, and the solution to the problem is typically considered in the determination of appropriate depreciation rates. Because of this, the following discussion will center on abandonments, recognizing that the treatment of involuntary premature retirements and significant retirements due to unforeseen events is similar.

**Economic and Financial Implications**

One of the arch-principles of regulation is that ratepayers should only pay for prudently incurred costs. To put it somewhat differently, investors are to bear all imprudently incurred costs. Consequently, where the costs of the abandoned project were imprudently incurred, the issue of who should bear these costs is settled. While the determination of whether costs were imprudently incurred is one of the most difficult and controversial points, if viewed, from a definitional perspective it is quite simple. Imprudent costs are those in excess of what was needed to produce the same quantity and quality of service based on the facts and circumstances at the time the costs were incurred.

Where costs are prudently incurred, the issue of who should bear them is perhaps not so obvious. Some have suggested that to permit an investment in an abandoned project to be included in the revenue requirement is to provide for an overrecovery of them. This conclusion is not correct. From the fact that the cost of capital, and more specifically the cost of equity, already absorbs compensation for perceived risk. The essence of risk, or to be technically correct, uncertainty, is the possible failure or inability to recover fully the required return of and on invested capital. It is universally accepted that the higher the perceived uncertainty, the higher the required compensation to bear that uncertainty and the higher the required return. Given this, it is contended that since abandonment has always been a possibility known to investors, compensation for that possibility has always been a part of the cost of capital. Hence, some contend that when the event materializes, investors should bear its full cost because they have been compensated for bearing that uncertainty (or risk) and to include that cost in the revenue requirement would allow for double recovery.

Whether this view has merit hinges critically on the regulatory principles that investors have and should have perceived to have applied. Specifically, if investors perceive regulation as a process limiting exposure to substantial loss, then the quantum of risk compensation they embody in the cost of capital is far smaller than if investors perceive regulation as only limiting excessive earnings, with no protection on the downside.

It is our view that both logic and history suggest that regulation has sought to minimize the cost of capital, and hence rates, by significantly constraining the circumstances under which investors are asked to absorb the costs of projects gone sour. While an historical review of regulation is beyond the scope of this paper, it would be useful to consider why regulation has acted in this way.

One attribute of a public utility is the nature of the service it provides. Its product is a necessity. Consequently, as a matter of public policy, regulation has sought to ensure that the service is rendered even under adverse circumstances and at least cost. Consider the latter point first. Since, in our economic system, capital cannot be unencumbered, capital costs are minimized by minimizing the risks to which that capital is exposed. To ensure adequate and reliable service, regulation has allowed for the recovery of costs that hindsight would find were improvidently, if not imprudently, incurred. This is to be contrasted with the nonregulated sector of our economy. A nonregulated firm, operating in a competitive environment, in the same circumstances, would not be able to recover such costs from its customers; they would be borne by investors.

In view of the foregoing, it would be heroic to posit that investors in regulated utilities embody in their required return on investment a compensation for risk as if that utility were exposed to the same market vagaries as a nonregulated firm. While not a theoretical argument, it is difficult to believe that investors have been compensated in the allowed return on equity for the magnitude of the costs of the abandonments we have seen in the electric utility industry of recent years.
As mentioned, customers are not to bear imprudently incurred costs. As also mentioned, regulation has as its goal the provision of service at minimum cost to ratepayers. The intriguing question is: Can regulation do both? The answer is that perhaps it can and perhaps it cannot, depending on circumstances.

Assume an electric utility with $1 billion of total capital, including $350 million of common equity, and assets consisting of $300 million of net plant and an investment of $700 million in a single project under construction. To crystallize the issue, assume all would agree that the entire $700 million cost associated with this project is imprudent. Could such a utility survive regulation to require investors to bear all the imprudent costs? The answer clearly is no. Such a utility would be unable to meet the cash obligations of its existing debt investors and could be unable to obtain additional capital on anything approaching reasonable and traditional terms. If in fact the plant under construction were not needed to meet load requirements, given the current level of demand, then it can be seen that costs to customers could well be lower. The utility would petition for bankruptcy and reorganized than if consumers were asked to bear the costs. Without the rates in the future would be lower would depend in part on the response of the capital markets to this event. Clearly, the cost of capital under such circumstances would not decrease. How much it would increase is, of course, unknown. Also to be considered is the effect of such an event on the cost of capital of other utilities operating in that jurisdiction. We need only look to Con Ed's past and recent events on the market price of all electric utilities to realize how decisions involving one utility affect nearly all of them. Neither was the effect of the Three Mile Island disaster confined to GPU. The point is that regulation must recognize that while its powers are jurisdiction in which it governs, the effect of its decisions knows no geographical limits.

The conclusion, while unfortunate, is clear. The denial of a return of or on capital in the case of an imprudent project may reduce the cost to the ratepayers of the affected utility, but it may raise the cost to consumers in other jurisdictions, depending upon the magnitude of the costs investors are asked to bear.

Fortunately, most abandonments or significant premature retirements do not have this result. In other words, given their relative size, denial of recovery does not typically produce a perceptible effect on the costs incurred by other utilities.

Next to be discussed are the economic and financial implications of the alternative treatments of the costs of abandoned projects deemed prudent, where investors are asked to bear a portion or all of the costs. For example, consider a decision whereby the utility is allowed to recover the costs over time but is not allowed to earn a return on the unrecovered balance. In that case, equity investors, being the residual owners, would bear the cost of the failure of the utility to recover not only the equity return but also the associated interest and preferred dividend obligations. Assuming that the rates established would otherwise have allowed the utility to earn the allowed rate of return, it can be seen that the utility would indeed earn below that which was authorized. In that case, the utility's market-to-book ratio would be below unity.

Were regulation to respond to this state of affairs by increasing rates in order to raise the market-to-book ratio, it would be self-defeating. In other words, the requirement that investors bear a portion of the costs of the abandoned project has as its corollary substandard earnings and a market-to-book ratio less than one. To raise rates to alleviate this situation is to relieve investors of the burden imposed in the first place and to shift it to consumers. Hence, regulation must be aware of the implications of assigning a portion of these costs to investors, and it must be prepared to accept them over the long term.

One of the more important implications of assigning these costs to investors involves the cost of capital. Clearly, if investors understand that a rule of the regulatory game is that prudently incurred costs be recovered from consumers and if that belief is embodied in the cost of capital, when that rule is broken the cost of capital increases. How much it increases will depend not only on the facts of the case at hand but also on the potential for application of the new rule to other projects. If the cost of capital rises, regulation must be careful in subsequent rate cases to impute a cost of capital to that utility equal to what it would have been had the abandonment not occurred. In contrast, if the rules of the game as perceived by investors are consistent with the regulatory treatment of the costs of abandonment, then no increase in the cost of capital will result.

As in the case of imprudent projects, whether the ultimate cost to ratepayers is lower when a portion of the costs is assigned to investors depends on the circumstances. Such an action could preclude the utility from financing needed projects. The additional costs of that failure could exceed the savings produced by assigning some abandonment costs to investors. As was also the case with imprudent projects, regulation must be concerned with the effect of its decisions on other utilities and their customers.
Conclusions

The discussion of the ratemaking treatment of prudent and imprudent abandoned projects reveals the following: Investors have and currently are expecting regulation to demand that they bear all of the costs of imprudent projects. Compensation for this risk has been and is being embodied in the cost of capital and hence in rates. The consumers who provide the payment for this risk presumably receive a benefit in exchange, namely, that management will diligently avoid incurring imprudent costs.

This discussion also reveals that if investors have not expected to bear any of the costs associated with prudent but abandoned projects and are not to do so, they will rationally respond by increasing the cost of capital. In this case, unlike the case of imprudence, there is no benefit to ratepayers: this is so because even higher rates to consumers cannot result in more prudent management.

The signal that should be given to utilities is that investors will bear the full cost of any and all imprudent projects, provided that ratepayers can continue to obtain safe and reliable service. Furthermore, investors must believe that regulation will not allow them to recover indirectly those costs which had previously been directly disallowed. Moreover, investors should be assured that they will not be penalized for costs of abandonments or premature retirements if those costs were prudently incurred. In this way, the lowest cost to consumers will result.

While each commission is responsible for regulating the utilities under its jurisdiction, it is responsible to the customers of those utilities, regulators must recognize that the effect of their decisions may very well extend beyond those utilities and that their rate-making decisions that serve to lower the cost for one group of ratepayers may increase the costs to others. Hence, consumers in general could be made worse off.

Addendum

Comments of Bruce M. Louieselle

Regarding the Financial Impact of Alternative Rate Making Treatments of Abandonment Losses

The purpose of this addendum is not to argue in favor of any particular ratemaking treatment of abandonment losses. Rather, it is to set forth the various effects on the utility's financial parameters given alternative ratemaking treatments of those losses. The point is simply this: Regulatory commissions can best serve the public interest only if they fully understand all the implications of their decisions. It serves no useful purpose to mask the real world implications with banal generalities.

While an infinite variety of alternative treatments of abandonment losses is available to commissions, my focus will be on only a few. Table 1 sets forth a simplified example showing the implications attendant to the amortization of a loss over ten years. In this example I have assumed that the abandoned plant was under construction, which was not included in the rate base, and that the company had a 100% equity ratio.

It would be well to consider first the implications of no recognition in rates of the abandonment loss. Assume, as we have assumed in the example, that the AFUDC would have been $100, so that because even higher rates to consumers cannot result in more prudent management.

The signal that should be given to utilities is that investors will bear the full cost of any and all imprudent projects, provided that ratepayers can continue to obtain safe and reliable service. Furthermore, investors must believe that regulation will not allow them to recover indirectly those costs which had previously been directly disallowed. Moreover, investors should be assured that they will not be penalized for costs of abandonments or premature retirements if those costs were prudently incurred. In this way, the lowest cost to consumers will result.

While each commission is responsible for regulating the utilities under its jurisdiction, it is responsible to the customers of those utilities, regulators must recognize that the effect of their decisions may very well extend beyond those utilities and that their rate-making decisions that serve to lower the cost for one group of ratepayers may increase the costs to others. Hence, consumers in general could be made worse off.
Table 1. Effect of Amortization of Abandonment Loss on Revenue Requirement

<table>
<thead>
<tr>
<th>Item</th>
<th>Before reflecting abandonment</th>
<th>Adjusted for abandonment</th>
<th>After abandonment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue requirement</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assumptions:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross loss on abandonment</td>
<td>$1,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tax reduction due to abandonment</td>
<td>$400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amortization</td>
<td>10 years</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unamortized loss excluded from rate base</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenues</td>
<td>$4,000</td>
<td>$4,000</td>
<td>$4,111</td>
</tr>
<tr>
<td>Oper. expenses</td>
<td>$1,148</td>
<td>$1,148</td>
<td>$1,148</td>
</tr>
<tr>
<td>Depr. and amort.</td>
<td>$1,000</td>
<td>$1,000</td>
<td>$1,100</td>
</tr>
<tr>
<td>Income taxes</td>
<td>$852</td>
<td>$812</td>
<td>$863</td>
</tr>
<tr>
<td>Net operating income</td>
<td>$1,000</td>
<td>$940</td>
<td>$1,000</td>
</tr>
<tr>
<td>Rate base</td>
<td>$10,000</td>
<td>$10,000</td>
<td>$10,000</td>
</tr>
<tr>
<td>Rate of return</td>
<td>10.00%</td>
<td>9.40%</td>
<td>10.00%</td>
</tr>
</tbody>
</table>

Assumptions:
- Net of tax abandonment loss: $1,000
- Cost of capital (discount rate): 12%
- Amortization period: Variable

Present value results:

A. Amortization over 3 years
1. Present value of recovery: $845.92
2. Percentage of net loss: 84.59%

B. Amortization over 5 years
1. Present value of recovery: $761.76
2. Percentage of net loss: 76.17%

C. Amortization over 10 years
1. Present value of recovery: $596.70
2. Percentage of net loss: 59.67%

D. Amortization over 10 years, starting 3 years hence
1. Present value of recovery: $424.70
2. Percentage of net loss: 42.47%
use of various amortization periods where the unamortized loss on abandonment has been excluded from the rate base. In deriving these present values, the discount rate was set equal to the assumed cost of capital, 12%.

Given these assumptions, it can be seen that a three-year amortization period selected, the investor would recover 84.59% of his investment and would lose 15.41%. Were a five-year period used, the recovery would fall to 76.17%, based on ten years it would fall to 59.67%. Thus, while the investor would recover the entire loss, assumed to be $1,000, the failure to include the unamortized portion in the rate base, upon which a return could be earned, would result in a real loss to the investor. To put these values in a somewhat different light, an investor with a 12% opportunity cost would be equally well off were he to receive $596.70 at the midpoint of the first year after abandonment as he were a ten-year amortization used.

It should be noted that the unamortized loss included in the rate base, the present value of all alternatives shown in Table 2 would be $1,000. To see the relationship between the values shown in Table 2 and the implications of the immediate write-off alternative, consider the situation in which a regulatory commission, for whatever reason, finds that the loss should be "shared" 69.67% by consumers and 40.33% by investors (Table 2, Alternative C). This same result could be produced were the commission to order an immediate write-off of 40.33% of the net loss and a full return of and on the remaining 59.67% over, for example, a three-, five-, or ten-year period. As was mentioned, however, were the commission to choose the amortization without rate base treatment in order to produce this "sharing," the company would be put in a position of chronically earning below the stated cost of capital. If capital attraction is a potential problem for the utility in question, the immediate write-off of a portion of the loss may be a superior alternative.

The purpose of Table 3 is to expand on the assumptions inherent in Table 1. In Table 1 a 100% equity ratio was used. Table 3 presents a more realistic capital structure. Given the fact that all losses inure to the detriment of equity investors, it is obvious that the more leveraged the capital structure, the greater will be the effect of any loss or regulatory treatment, except full return of and on the loss, on the equity owner.

In conclusion, there is a myriad of alternative treatments of losses resulting from plant abandonment available to commissions. The implications for consumers and investors are not always self-evident. Consequently, advocates of any alternative should trace through and present the immediate and long-run implications of whatever alternative is
Electric utility regulation will be confronting its most challenging and critical period over the next several years. Powerplants will be completed, powerplants will be abandoned, and in each instance regulators—and I dare say the courts—will be called upon to address issues of unprecedented significance and proportion. The response could go a long way toward reshaping the electric utility industry as we have come to know it.

Let us consider first those plants which will be completed. At a minimum they are likely to carry price tags well above anyone's expectation. Equally probable, they are likely to represent increments of capacity which no longer can be justified either because load growth has fallen far short of expectations or because the economic benefit associated with the displacement of expensive generating capacity no longer is evident—or both.

In either event utility commissions will be asked to pass upon the propriety of including those additions, in whole or in part, in ratebase. The rate jolt, particularly in the case of utilities that have been denied the capability to include CWP in ratebase, could be significant, and commissions will be under understandable pressure to deny ratebase inclusion at all—or, for example, by finding that the capacity or some portion of it is not needed and therefore is not used and useful in the rendition of public utility service—or to adopt a rate-phase-in approach.

At the outset it should be clear that in this portion of the discussion we are assuming that actual construction activities were prudently managed. If imprudence is found, the excess capacity or rate phase-in issues are irrelevant, for recovery is denied at the threshold. Let us first consider the problem of excess capacity. The combined effects of long construction lead times, economic recession, and price elasticity—coupled with the understandable desire to take advantage of the economies of scale—has made the problem of excess capacity a real one.

Two questions are presented: When is capacity excess? Assuming the existence of excess capacity, what regulatory measures, if any, are appropriate?

The question of whether there is excess capacity has itself been addressed in two ways. Some commissions, in part because of strict statutory mandates, have applied a rather rigid used and useful standard or test. When, then, is an increment of capacity used and useful? It is obviously used when it is placed in service. But that begs the question, for what if the consequence of placing a unit in service is the rendering of other units functionally obsolete, or the creation of an unrealistically high reserve margin?

Let us step back a moment and place the used and useful concept in its historical setting. Its roots are thought to be of a constitutional nature, for it long has been considered the case that investors are entitled to a return on properly committed to public service. That, however, merely poses another question: Is properly devoted to public service when it is excess? Only one answer is possible, a qualified maybe.

Let me begin with oversimplifications. If a unit is likely to come into service during the period for which rates are being set, it is generally agreed to be used. Some commissions have taken an even more lenient attitude: A unit is considered used if it will be in service in the foreseeable future, even if that future is not until the expiration of the period for which rates are being set.

But the satisfaction of the used test only serves to get us deeper into the briar patch, not out of it. The fact that a unit is used does not suggest—or resolve—that it is useful. For example, is a unit useful if without it, or without a significant portion of it, a utility would still satisfy its reserve requirement? Many commissions have answered in the negative.

In passing on the question we must not, I suggest, be guided strictly by reliability criteria. Obviously, the unit should be considered useful if its availability is necessary to achieve the desired loss of load probability or alleviate regional stability problems. Those tests are easy to apply. But other tests are equally relevant, in particular economic need. If the addition of an increment of capacity
will produce lower system costs, then I suggest that the unit is useful notwithstanding the reserve margin that it produces. It assuredly would be folly to adopt a regulatory construction of useful and unneeded which would have the effect of discouraging development of a least-cost generation mix.

One might respond that if an increment of capacity is cheaper than existing capacity (considering the combination of capital and O&M costs) but nevertheless results in the creation of unrealistically high reserve margins, the remedy should be exclusion from the base of the less efficient unit. But is that the signal to give the utility that encourage the kind of long-range planning that truly is beneficial to ratepayers? And let us not forget the economies of scale associated with larger units. Do we want to make those economies in the future by signaling to utilities today that only a portion of a plant will earn a return, with the remainder being deferred until it is justified by growth? Several commissions have recognized this dilemma and have refused to penalize a utility for building an efficient unit simply because a portion of it appeared excessive.

Before we consider an alternative approach, let us briefly examine what the regulatory response has been to negative determinations under the used and useful standard. At the outset I should point out that by far the majority of commissions have declined to impose a penalty notwithstanding the reality of excess capacity. They have been moved by a variety of considerations: the long lead time associated with new capacity; the effect of regulatory delays and changing regulatory (for example, HAC) requirements; the impossibility of accurately projecting load growth; and the utility's reluctance to mitigate, including the promotion of off-system sales, postponement of completion dates, or retirement of older units.

Only a handful of utility commissions have actually imposed the most drastic penalty of all—exclusion from rate-base or the imputation of revenues (presumably from hypothetical sales) at a level equal to the net present value of the reductions of including the capacity in rate-base. I should add that whenever this extreme remedy has been imposed it has been accompanied by a determination that the excess capacity was the consequence of utility imprudence.

Some commissions have adopted variations of this unit exclusion approach: allowing the new unit in but excluding an older, substantially depreciated unit from rate-base (in essence treating the older unit as no longer used and useful); or declaring to identify any particular unit as excess, but reducing the overall rate-base in proportion to the amount determined to be excessive.

Typically, when a commission denies recovery of all or part of a new unit, it does permit the continued accrual of AFUDC until the increment is needed. This, of course, has the effect of shifting the burden to future ratepayers, a result which is not entirely free of inequities, particularly where the decision to add capacity was a prudent response to the expected needs of current ratepayers.

Although not typical, utility commissions have on occasion denied ratebase inclusion but allowed recovery of the new unit's O&M. If this approach is not properly applied it can result in a double penalty to the utility. Properly implemented, the utility should be able to recoup the O&M expenses it would have incurred had it not completed the unnecessary capacity. That is, if the increment is a more efficient base-load unit which has the effect of displacing a less efficient intermediate unit, and if shareholders are deemed to receive a return on investment (as well as a return of investment), they at least should be able to reap the benefits of the added efficiencies they provide to the system. O&M should be recalculated to assume the unavailability of the excluded unit.

Other commissions have allowed the depreciation expense associated with "excess" capacity but have precluded recovery of an equity return—or even of carrying charges on debt.

Finally, regulatory commissions—most particularly the New York Public Service Commission—have permitted "excess" capacity to go into rate-base but have imputed off-system sales when estimating revenues. The utility is free to keep all off-system revenues up to the established level; for all off-system revenues in excess of that target level, there is a sharing between investors and ratepayers.

Let us return, for a moment, to the logic of the used and useful standard. In my judgment the events of the past several years underscore the desirability of reappraising the appropriateness of that concept. It may well be an anachronism which should now be replaced by a more flexible, dynamic standard. I have reference to the basic regulatory principle that utilities are to be compensated for prudent actions—and penalized for imprudent ones. Does it make sense rigidly to apply a used and useful test to new capacity which a utility is unfortunate to bring on line immediately after the consequences of an oil boycott are reflected in elasticity responses? Does it make sense to deny recovery of depreciation and return on investment where load declines, perhaps permanently, because of a recession, or because of the ravaging consequences of foreign industrial competition? I do not think not. The prudence concept has its genesis in the notion that utilities are to be managed by their managers, not by regulators with the benefit of hindsight. In a moment I will address the prudence concept to completed and abandoned units—in terms of the amount to be recovered or written off. At this juncture I am raising a narrower question: Why should a utility be penalized for having excess capacity if at every critical stage its decision to proceed with a
project was prudent. If it represented a reasonable decision under the circumstances that existed at the time? Why, for example, should a utility be penalized for responding to one administration's oil reduction objective simply because the objective fell into disfavor with a new administration?

The regulatory objective should be clear. Encourage the best possible decision making by utility managers at each stage of a construction program. One does not, I suggest, accomplish that in a climate in which managers are fearful of deciding. They must be given the assurance that they and their shareholders will not be penalized if they act reasonably under the circumstances that exist at the time.

Utilities must not be tested solely by whether their decisions turn out to be correct. That is not the test of prudent action, and rigidly applied it can only serve to stifle creativity to the ultimate prejudice of ratepayers. Regulators must be willing to proclaim that managers who act reasonably will not be penalized whatever hindsight proves to have been the correct course of action.

This is the standard that should govern all utility action, the problem of excessive capacity included. It does, however, impose definite responsibilities upon utilities. It is imperative, in my judgment, that utilities continually revisit generation expansion decisions, perhaps at least biennially and more often if new events are significant enough to warrant it. Utilities must develop, and utility commissions should insist upon, a "rolling" decision making process. The only way to establish the prudence of an historical decision—or that it was the product of good business judgment, the controlling standard in stockholder derivative actions—is to demonstrate that a decision in fact was made, and that, in its historical context, it was rational. My impression is that utilities are quite vulnerable on that score.

Not all construction programs result in excess capacity. Some result is capacity needed, if not for reliability purposes, then at least for least-cost operation. Others result in no capacity at all—abandonments.

The new unit at the Exelon nuclear plant. It certainly is not surprising that a commission which denied CNP will bridge at the rate implications of completion of a major construction project. The response is not hard to predict: (1) CNP will be made to dump the amount included in ratebase by invocation of the prudence test, and (2) phase-in will be considered for whatever remains.

To date I am only aware of one phase-in proposal that actually has been implemented. In October 1983 the Illinois commission approved a coal plant of lower Illinois Gas and Electric. In place of a one-time 26 percent rate increase, the utility will receive a cumulative 67 percent increase over seven years. Other phase-in proposals are currently under consideration, but thus far they have generated considerable opposition, particularly since most are premised on initiation prior to completion of the unit. Nevertheless, we surely have not heard the end of phase-ins, for the promise to which regulators have clung desperately in past years is now realized to be illusory: The high capital cost of new units will not be offset by lower operating costs, not even on most oil-fired systems in view of the virtual collapse of OPEC.

While phase-in schemes may resolve a current political problem, they are not without cost. Since we are presuming prudently incurred expenditures, in my judgment the amount deferred for future ratebase inclusion must be permitted to accumulate APRDS. As a result, the total amount included in ratebase will far exceed the true "prud" cost of the project. And that is what ultimately will have to be recovered in rates through depreciation charges, return, and taxes.

By far the greatest regulatory attention will be devoted to prudence investigations, the largest of which is now taking place before the New York commission in the case of the Shoreham project (and where the staff is supporting a $1.5 billion ratebase reduction). I have no problem with prudence investigations, provided the test is properly applied. The test is not whether the utility manager reached the correct decision, but whether he reached a reasonable one given the facts in existence at the time.

The escalating price tags now being projected for units under construction are causing regulatory commissions and legislatures to consider a new tool—a cap on the recovery of investment expenditures. The New York commission took that step in April 1982 following the conclusion of a proceeding to investigate the financial and economic cost implications of construction of the Nine Mile 2 nuclear unit. The commission adopted an incentive rate of return. It established a target completion cost which will be subject to modification in the future if expenditures increase or decrease as a result of extraordinary events. As stated by the commission, "the IROR will only apply to the equity portion of capitalization, it will be calculated by applying a constant sharing factor of 20% to the changing revenue requirement occasioned by any cost overrun or underrun from the target figure." The 20 percent sharing factor will then be applied against the utility's return on common equity, and the resulting dollar adjustment will be implemented either through a one-time adjustment to ratebase or by an equivalent amortization to income. The commission did provide that in no case could an IROR reduction in the return on common equity exceed one-half of the rate of return that the utility would otherwise be authorized to earn. Recently, following the announcement of an escalation in the unit's projected completion costs, the chairman of the commission has announced an intention to review the IROR proposal with the objective of tiering...
its effects; the penalty would be increased up to 50 percent for costs in excess of one designated level and up to 100 percent for costs in excess of a higher designated level.

The Connecticut legislature responded to the Millstone 3 project by legislating a cap and has provided minimal adjustment flexibility. Both the Nine Mile Point and the Millstone cap were established well into the construction of the respective units. This raises questions not only about fairness to investors—who invested on the assumption that prudent expenditures would not only be recovered but also permitted to earn a return—but also of constitutional propriety. Again, we are only talking about prudent expenditures; the New York regulatory approach, like the Connecticut statute, presumes that recovery of imprudent expenditures will be precluded through the separate mechanism of prudence determinations.

The only legitimate public interest is the establishment of a cap to provide the utility with an incentive to construct the plant within the prescribed target. An incentive, however, is only effective for elements of cost under the utility's control. Every Jones has a second Connecticut, that has created a rate-making approach comparable to a cap has recognized this central control factor.

A major distinction between an abandonment situation and plant completion is that the end result of the latter is the inclusion of some amount in ratebase, while the disposition of the former, where the utility is successful, typically involves an expense amortization.

By and large, regulatory commissions have taken three approaches following a determination of the amount that had prudently been invested in an abandoned project. The most extreme result is to deny any recovery at all on one of two bases. (1) Some commissions have used and useful standard as presenting an absolute bar to the allowance of any amortization of abandoned facilities. (2) Other commissions have reached the same result based not on the used and useful standard but on the existence of an anti-CAPF statute. On the other extreme, some commissions have permitted both an amortization allowance and a return on the unamortized balance. Finally, several commissions have taken the middle ground by either allowing full amortization of the incurred expenditures, including accrued ARRE, but not allowing a return on the unamortized balance (the approach adopted by the FERC) or allowing amortization of the out-of-pocket expenditures but not ARRE on the equity portion of the capital structure that was used to finance construction, but allowing carrying costs on the unamortized balance (the position taken by the Massachusetts Department of Public Utilities in connection with abandonment of the Pilgrim II project).

While the FERC position represents an obvious attempt to balance the risk of plant abandonments between stockholders and ratepayers, it is not obvious to me why stockholders should be denied continued accumulation of SFROC pending completion of the amortization write-off unless it is because of the expedient nature of the write-off as contrasted with typical ratebase depreciation following the completion of a project. The FERC has generally used an amortization period of between five and ten years. But it still remains the case that the amount being written off was prudently expended by the utility on the project up until the date of cancellation; that being the case, the logic of denying an equity return on its invested capital for the entire period of that investment (that is, until completion of the amortization) is not at all obvious. The FERC is quite clear in indicating that its methodology is an attempt to allocate risk. The issue is whether it is a cost-effective approach. I doubt whether equity investors heretofore have considered the exposure they face in the event of abandonments, notwithstanding the fact that the decision to abandon was itself a prudent one at the time it was made by the utility. Obviously, if the utility is denied any recovery of prudently expended expenditures, or even if it is confronted with the more moderate approach of the FERC, investors will have to take that risk into consideration in calculating their required cost of capital. The premium could be a significant one, for the size of the abandonments that regulation has confronted to date could well pale by comparison with those they will have to confront in the future.

The Pilgrim II situation dramatically demonstrates the necessity for a utility continually to reevaluate the appropriateness of its construction schedule. In 1980 the Massachusetts Department of Public Utilities undertook a comprehensive review of Boston Edison's construction program, determined that the Pilgrim II project was an appropriate component, and stated it should be completed. Two years later that commission determined the project should have been cancelled in 1981 and denied recovery of all expenditures incurred after that time.

Pilgrim II may well represent a watershed for quite a different reason. As is not uncommon in the case of large construction projects, particularly nuclear plants, that unit represented a joint undertaking by several utilities under the leadership of the Boston Edison Company. Subsequently, its determination that Edison was imprudent in failing to cancel the unit at an earlier date, the Massachusetts DPU had occasion to consider the implications of that imprudence in the case of several minority owners. It decided, in effect, that Edison was acting as an agent for the minority participants; therefore, those participants should bear the full consequence of the imprudent acts of their principal. One of the minority participants, the New England Power Company, is regulated by the FERC, not by the Massachusetts DPU. New
England Power has sought permission to amortize the full amount of its direct and indirect Pilgrim II expenditures. The DPU has intervened in opposition, contending that recovery should be limited to the expenditures incurred prior to the date on which the department determined the project should have been cancelled. The staff of the FERC is taking a somewhat different position. It contends that as a condition precedent to any effort to obtain recovery from ratepayers for that portion of its expenditures which the DPU has determined to be a result of Edison's imprudence, New England Power Company should first sue Edison.

Surely neighboring utilities will still cooperate where it is in the best interests of their respective ratepayers, but they will do so in an atmosphere of continually looking over their shoulders. I suspect the FERC staff would argue that it is a good thing, that the recognition it may be sued by one of its partners will make a utility more sensitive to the prudent management of the joint undertakings. But that pressure is there already; the penalty imposed on Edison for its alleged imprudence in the case of Pilgrim II surely was severe enough to counsel prudence in the future. I seriously doubt that the added penalty of liability to a joint owner will add any appreciable positive impetus toward sound management practices. But I do not at all doubt that the position of the FERC staff, if adopted by the commission, will have a subtle, chilling effect on interutility cooperative efforts, and that may be a very heavy price to pay.

It is imperative that we sort all this out with the long term in mind. It is imperative that we approach the terrible crisis which now confronts the industry not with the objective of achieving a short-term political expedient but with the intent to achieve a climate which truly encourages rational planning by the day-to-day utility manager. We will not achieve that if, after the fact, the utility manager is made to prove the correctness of every decision along the way. That simply is too much to expect of mortals.

The issues of excess capacity, or completion costs, of abandonment, whether viewed in the context of regulatory oversight or of any of the different types of shareholder actions, should raise a single issue: Whatever the decision made, was it the product of rational decision making at the time? One can ask for no more, and if we persist in seeking more, the likelihood is that we will get far less.

COMMENTS

Richard Walker

The scope of the subjects dealt with by Richard Lurito and Bruce Louiselle, William Gallavan and Bruce Smith, and Basill Copeland seems more than anyone can chew intellectually at one sitting. But their comments on some fundamentals deserve some attention.

First, let us look at the question of "prudence" of the initial expenditures—an issue which may predominate or be dominant in the regulatory treatment of each of these items. Lurito and Louiselle have drawn a simple definition which, with one critical elaboration, seems meritorious. They say that imprudent costs are "those in excess of what was needed to produce the same quantity and quality of service based on the facts and circumstances at the time the costs were incurred." However, as almost all of these decisions being judged involve predictions, their definition should, if it does not already, distinguish carefully between questions of prudence, on the one hand, and, on the other, the utter impossibility and incapacity of human beings accurately to predict the future.

This important distinction between imprudence and incapacity to predict should be recognized clearly. If investors are to be saddled with the difference between predictions of load and the load realized, which can take the form of either construction abandonment or capacity in excess of load, capital costs will soar. Thus, the regulatory goal of minimizing the cost of capital and therefore utility rates, stated by Lurito and Louiselle, would not be achievable.
It should be noted that if investors are to receive the financial penalty of differences between capacity available as a result of prudent actions and capacity needed after the construction is completed, they should also receive extraordinary returns when capacity is fairly balanced with loads with no upper cap, as would an industrial company. Some would oppose this investor compensation plan as outrageous for a quasimonopoly, but it is clearly the opposite side of the coin which needs: Penalize the investor for inability to predict the future.

The idea of assessing financial penalties for failure to predict accurately is an intriguing one. Econometric studies of consumption, employment, prices, interest rates, international trade, and other factors frequently underlie the basic assumptions used by utilities in predicting loads for five to fifteen years—the time horizon needed if thermal efficiencies are to be maintained or improved and economy achieved. Yet, the economists have failed dismally for the last fifteen years to make good predictions; even to such an extent that many of them question the very usefulness of the econometric process.

Lester Thurow, the great MIT scholar, sized up the situation in his recent book, The State of Economists: In a chapter entitled, "Econometrics: An Ice Breaker Caught in the Ice," Thurow writes:

In the 1950's when econometrics first emerged, the discipline was seen in America as an icebreaker that would lead the economics profession through the ice pack of conflicting theories. Unfortunately, the icebreaker failed to work. The problem began with the inability of macroeconomic models to predict the adverse events—soaring inflation, stagnant employment, the cessation of productivity growth that were about to hit us in the 1970's. That failure to predict led to a breakdown in both the economics professions-confidence in econometric results and the public's confidence in economics.

Therefore, those who would lay blame and assess penalties for these failures to see the future with precision could, out of fairness, as readily go after the economists for the dismal job of forecasting they have done as to attack utility management and investors. The economists' performance so far in 1984 appears to be horrendous. While preposterous, it would make as much sense to assess a head tax on each economist for each significantly incorrect economic forecast for each year of significant error. Charitably, those who
cannot pay cash might be permitted to pay by working as utility bill collectors in the economically deprived areas of our large cities.

The Importance of Carefully Identifying the Difficulties of Predicting the Future and Distinguishing the Effects of Error of Such Estimates from Other Decisions Is Pointed Up in the Paper by Basil Copeland. He notes, correctly I believe, that reserve margins in the magnitude of 15-20 percent have been used as standards to avoid outages because of equipment failures, maintenance, and so forth, that is, "loss of load probability," or "machines breaking down" concepts. He states that increases of reserves of 50-100 percent larger than this are not justified by unit size.

I believe that viewpoint misses a number of important considerations. First, many public utilities are required by law to provide adequate public utility service. In this day and age, a loss of load in many areas can be chaotic if not catastrophic, possibly with enormous social and political costs. Therefore, utilities should have a high level of confidence—say, at the 95 percent level—that they will have adequate reserves to avoid loss of load.

If a utility must have a 15 percent reserve capacity to produce an acceptable loss of load probability [which may be required by law] and this is, say, at a 90 percent plus confidence level, then the variability of loads achieved, loads which of course must be predicted years in advance, makes it almost a mathematical certainty that the actual reserves realized with the addition of new units will from time to time be in the 25-30 percent range, even with a standard error of estimate of only 4 percent. (Four percent does not seem an excessive expectation for an eight-year horizon view of past experience in estimating electric loads and economic performance.) Reserves in the 40-50 percent range would be a distinct possibility with less accurate forecasts—also a distinct possibility over horizons of five and twelve years. Thus, while Copeland may be correct in stating that a reserve increase from 50-100 percent is not required by increased unit size, increases of that magnitude are a virtually certain result of humanly unavowable forecast errors looking out over five to twelve years.

Copeland also indulges in what I believe is a common error in proposing public utility pricing policies—the error of believing that an efficient and satisfactory policy can be developed based on treating customer interests ("consumer sovereignty") as paramount if not exclusive. In establishing policy, the interests of customers and investors must be considered mutual. Punitive actions toward one or the other, or short-run advantages for either, are not likely to be features of sound policies.
I think William Gallavan has provided a good outline of the various rate-making options available in the face of a major addition of plant to a utility's system. I am concerned, however, with one of the implications of his discussion. He seems to imply that the current saw-tooth pattern of plant additions will continue into the future. I am not sure that this will be the case to the extent it has been in the past.

It should be recalled that adding smaller increments of capacity does have a number of advantages. It can provide for a better matching of capacity and demand. It can have a lesser financial effect on the utility company, better maintaining cash flow and earnings. It can lower reserve requirements, since these are often stated in terms of the largest units on a given system. Finally, there is the potential for better generating facility reliability. Higher capacity factors of smaller units could offset some of the supposed economies of scale of larger units.

It also seems to me that many electric utilities will choose to enter into supply contracts rather than build their own large central station units in the future. We have already seen signs of this, for example, in the contracts between the New England utilities and Hydro-Quebec. It has also become more common to have interpower-pool exchanges of power. I would expect such energy and power transfers to continue into the future and even become more popular.

Basil Copeland raises the point of lowering prices in the face of excess capacity. Indeed, that is the classic approach to overcapacity in most industries. Perhaps a sensible way for electric utilities to address this problem is to lower prices to the most elastic demand. The Narragansett Electric plan recently approved by the Rhode Island commission does just that by offering discounted electric rates for incremental industrial energy use in the state. Such a plan did not forgo the higher costs of capacity completely, but rather was designed to ameliorate the rate effect of excess capacity on all customers.

Richard Lortie and Bruce Lussier have presented their usual thoughtful and thorough views on the implicit considerations weighed by public utility commissions in determining the rate of return for utility companies. I have only one point to add. Abandonment of a plant under construction, combined with investors absorbing a share of the costs of such abandonment, does not necessarily imply substantial earnings for the given company. Once a plant has been abandoned and a decision has been made by the regulators to permit a write-off of the facility, the company can consolidate its capital structure (that is, reduce short-term debt), improve cash flow, improve its stock and bond ratings, and improve cash (that is, real) earnings compared to those during the construction phase. As an example in Massachusetts is found in Boston Edison Company, which, after abandoning its Preliminary power plant and receiving a partial write-off of its investment in the plant from the commission, found its earnings, capital structure, and relationship with the financial community greatly improved.

One other issue needs to be addressed in this session, that of the responsibility of a minority owner of an abandoned plant where imprudence has been found in the majority partner. Our department has ruled that a minority owner should be imputed the imprudence of the majority owner in regard to the recoverability of the minority owner's share of the investment. We have also urged the FERC to enforce upon minority owners the responsibility to attempt to recover costs of imprudently constructed abandoned plant from the majority owner before attempting to recover such costs from ratepayers through wholesale rate increases.
Part Seven:
*Integrating Costly Plant and Excess Capacity into Electric Utility Rate Structures*
Reaction to the extreme changes in revenue requirement caused by the addition of new plant under conventional treatment, a reaction which is frequently referred to and summarized as "rate shock," has prompted a new consideration of optimal intertemporal allocation. The concept of fair and equitable ratemaking, so extensively discussed in the basic regulatory textbooks, has in the past not included the problem of efficient intertemporal allocation of ratebase. The conventional approach has been to take the revenue requirement in any particular year as a given, as if each year were separate from and independent of the years preceding and following.

When allocating costs of long-lived assets, the ratemaker concerned with fairness, efficiency, and equity must explicitly deal with intertemporal allocation. When expensive new plants are being added to ratebase, the fairness, efficiency, and even adequacy of the related rates will be determined as much by the ratemaker's allocation of costs across time as by the allocation to different customers and different customer classes within a particular rate year. Under conventional regulatory treatment, new investments are added to ratebase and customers are charged in a manner

Note: The views expressed here are those of the author and do not necessarily represent those of the New York Public Service Commission.
which front-loads the expense. Front-loading forces present customers to pay the costs of a plant which will benefit future customers. The logic of this approach is reflected in customers' refusal to accept company and regulatory commission assurances that a plant is being built to save money even though rates increase, at least in the near term, as a consequence.

The basic argument of this paper is that if a large base-loaded plant is built for fuel savings such that total system costs over the plant's life are expected to be lower with the plant than without, then customers' rates should be lower with the plant than without it in all years of the plant's operation, and not only after it has been in operation for ten to twenty years; to do otherwise forces the customer to be, in essence, an unwilling investor in the utility. Any system of intertemporal cost allocation which results in customers being worse off with the plant than without it in any year results from misallocation of costs, and the resulting rates will not pass the standard criteria of fairness, equity, or efficiency. Such a misallocation is unnecessary. This paper argues that ratemakers should explicitly consider the intertemporal allocation of all fixed costs and propose a mechanism by which it is possible to allocate fixed costs in a more efficient, fair, and equitable pattern while maintaining the present value of returns to investors.

Suboptimal Intertemporal Allocation

The intertemporal suboptimality problem just described is primarily due to inflation. To the extent the problem would exist in the absence of inflation, it is vastly exaggerated by the current inflationary situation.

Theoretically, the value of an asset changes each year according to the change in the present value of the income stream which it will produce over the rest of its life. By ignoring the effects of inflation conventional methods of calculating the first-year cost of new assets result in wildly exaggerated estimates (unless test absences are even greater than inflation).

There are two ways to illustrate the distorting effects of inflation. The first is based on what I will call the "slippage" argument. The second is more complex but more theoretically accurate, being based on the true changes in economic value of the asset and reflecting this change in the asset's depreciation schedule.

We will first use the "slippage" argument to illustrate the effects of inflation; however, the remaining part of the paper will be based entirely on the more theoretically exact depreciation computations.

In their work on marginal cost pricing, Charles Cicchetti and others showed that the familiar annuity formula or "capital recovery" formula shown below can be derived from the cost change resulting from slipping a project for one year. The familiar annuity formula represents the difference between the original stream of costs and the slipped stream.

NERA, in the appendix to the EWWI series, develops the same annuity formula with the explicit inclusion of inflation. NERA concludes that the annuity formula is no more than the special case of their formula and is proper to use in the absence of inflation. The annuity formula for an end-of-year payment is shown as Equation (1):

\[
\text{Cost in each year} = K_0 \frac{r}{1 + \frac{r}{1 + r^{n-1}}}.
\]

The NERA version, which produces a stream of payments leveled in real terms, is shown as Equation (2):

\[
\text{Cost in year } t = K_0 \frac{(1+r)^t}{(1+r)^n} \left( \frac{(1+r)^n}{(1+r)^{n-1}} \right).
\]

where

\[K_0 = \text{cost of new plant};\]
\[\hat{K}_0 = \text{discounted present value};\]
\[r = \text{real interest rate};\]
\[\pi = \text{rate of inflation};\]
\[n = \text{life expectancy of plant};\]
\[t = \text{life of plant};\]
\[\Delta t = \text{annual cost for the first year or year zero}.\]

The initial slippage argument was derived by asking: If load decreased (increased) such that a project could be deferred (accelerated) for one year, what would be the cost savings (penalty) be? The answer was presumed to provide an approximation of the marginal cost associated with a change in load with respect to the specific plant being accelerated or deferred.
A simplified example of this argument can be presented by assuming that the investment project under consideration will last forever. Assume that an investment costs $1,000, there is no inflation, and the rate of interest is 5 percent. If a decrease in load forecasts allows the deferment of this project for one year, the cost savings associated with the load decrease will be 5 percent of $1,000, or $50.00. Thus, we might say that the marginal cost of this project is $50.00.

Now consider an inflationary rate of 5 percent and a cost of capital of 14.45 percent instead of the non-inflationary 5 percent. It should not take a great deal of thought to question the conclusion that a 9 percent rate of inflation could cause the real marginal cost of a project to increase threefold, from $50.00 to $154.50; nonetheless, this is precisely what occurred and what has been imposed on ratepayers by companies and commissions across the country. In see how this happened notice that the cost of capital always reflects inflationary expectations even if such expectations appear nowhere else in the computation. A straight application of the non-inflationary logic to the inflationary situation would imply that since the cost of capital was 14.45 percent, the cost savings associated with a one-year deferral of the $1,000 project would be $144.50, and that the marginal cost of the $1,000 project therefore would be $144.50.

Looking more closely at the deferred project in a time of inflation, we see that in the same year that we have saved $144.50 in interest payments on the $1,000 project, the original cost, thanks to the 5 percent rate of inflation, has risen to $1,090. If we wish to measure the true cost changes resulting from the one-year deferral, the effect of inflation on the cost of the project must be included. Thus, we have saved $144.50 in interest payments but are faced with a $90.00 (9 percent) increase in the project's cost; therefore $144.50 minus $90.00, or $54.50. In a competitive market, the rental price for this piece of equipment would approximate $54.50. The $144.50 charge could not exist for long except in fantasy or in a regulated industry, as the following should make clear.

A truly striking difference between a competitive market and a regulated environment lies in which component becomes the residual. In the market, the price is determined and investors decide whether it is worthwhile to invest at the market price by comparing the cost of the investment to the present value of its income stream. Once the investment is made, misjudging inflation effects causes problems in the firm's income reporting over time. Specifically, income might be underestimated in the early years. As a large subsidy is added and later overreported, in a regulatory environment in which investments are made first and prices then set as the residual, the same mistake leads to gross mispricing and consequent misallocation of resources.

Avoiding Rate Shock

The error of looking at the annual cost of an asset in terms of only the cash flow cost can be easily seen by taking an extreme example. Suppose that a condominium in Brazil costs $50,000 this year. Further suppose that the rate of inflation is 100 percent, and the cost of capital is 110 percent. Following conventional regulatory practice, the annual cost of the condominium figured as the cost of capital for one year would be $55,000 plus depreciation and expenses. If we ask what rent could be charged under the assumption of a competitive market for condominiums, it should be clear that no one would rent the condominium for $55,000. It should also be clear that a competitive market would bid down the rent to something in the neighborhood of $5,000.

Looking at the condominium from the point of view of the owner, in one year the money payments for the condominium would be $5,000, but during the same year the capital gain due to inflation would be $50,000. Thus, the net cost to the condominium owner would be $55,000, but during the same year the capital gain due to inflation would be $50,000. Thus, the net cost to the condominium owner would be only $5,000 per year, and any rent over that amount would be a profit.

The conventional method of charging new plants in regulated industry is analogous to charging $55,000 for the first-year rental of a $50,000 condominium. Of course, if the inflation rate were really 100 percent, then the error of this approach would be obvious to all. It is only when the inflation rate is in the moderate U.S. range that the distortions are small enough to allow the method to continue, while still being large enough to cause harm to the consumers and misallocation of resources in the economy.

Before proceeding to the details of the numerical computation, let us turn to the primary reason for concern about intertemporal allocation. In my view, the overriding goal and purpose of regulation is the efficient allocation of resources. In order to have this efficiency, we must have enough prices. These are prices which equal marginal costs. Indeed, the only way to avoid the misallocation of resources is to present both producers and consumers with a set of prices equal to marginal costs.

Intertemporal allocation is important only insofar as the misallocation of costs over time leads to an annual revenue requirement which constrains prices to be greater than or less than marginal costs. The objective of economic deprecia-

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Intertemporal allocation is important only insofar as the misallocation of costs over time leads to an annual revenue requirement which constrains prices to be greater than or less than marginal costs. The objective of economic deprecia-
costs. Revenue requirement is greatest when marginal costs are smallest, and marginal costs are greatest when revenue requirement is smallest. In addition to forcing present customers to pay for plant that will largely benefit future customers, this standard approach leads to a mispricing and misallocation of resources much of the time.

The addition of new base plant for the purpose of fuel savings causes marginal running costs to fall from the level at which they were before the addition. At the same time, inflation causes the new plant to be nominally more expensive than previous base plants, and it also causes the traditional stream of payments over time to become front-loaded. These two effects frequently cause the company's revenue requirement to increase substantially. This increase in conjunction with the decrease in marginal costs causes difficulties in achieving optimal pricing, difficulties in financing, and difficulties in customer and commission acceptability.

The good news is that the problem is primarily caused by the traditional way of allocating fixed costs over time and can be corrected. Basically, the allocation of fixed plant over time is a function of the depreciation schedule chosen. Very little economic work has been done on optimal depreciation other than to note that existing depreciation tables tend to be arbitrary. Even an arbitrary approach, if continued for a number of years, tends to pick up a certain inertia and to become the unquestioned and uneconomic "traditional" method. It is this trap from which the industry must now extricate itself.

At a minimum, most of the problems associated with the introduction of new large base units can be eliminated by simply removing the intertemporal distortions caused by inflation. At best, the methods we develop for removing these distortions can be further applied to give a pattern of revenue requirements over time that matches the changes in marginal costs over time and which therefore matches the revenue streams over time if prices are set equal to marginal costs.

Figures 1 and 2 illustrate the situation in a hypothetical electric company. In Figure 1, a new expensive base plant has just been added to the ratebase. Figure 2 shows the same company twenty years later. The characteristic distinguishing these diagrams from those of the introductory economics textbook is that, for our purposes, average total cost is the total unit revenue requirement as measured and defined under current conventional ratemaking. For revenue requirement purposes, fixed costs are measured according to embodied cost procedures rather than the opportunity cost measure of economic price theory. This is a crucial distinction because it implies that rather than having to accept the relationships shown in the figures, we are able to shift the curve labeled average total costs, as an instrument of policy, in such a way as to approach optimization over time.
From an economic perspective, the requirement of regulation is to provide a utility with a rate of return on its investment so that it makes a zero economic, or excess, profit. In other words, its return should be comparable to other investments with similar risks. Therefore, a regulatory commission will attempt to set the price at $p$, where the average total cost curve intersects the demand curve. As can be seen from Figure 1, this point is substantially above the point at which the marginal cost curve intercepts the demand curve. The area $arb$ represents the loss to customers from pricing at $p$ rather than pricing at $a$, where price equals marginal cost. The area $rda$ represents the real loss to the service territory caused by mispricing. This loss is often referred to as a deadweight efficiency loss because it is caused by resource misallocation and, in the language of lawyers and pamphlet writers, it has no "socially redeeming qualities." It is waste pure and simple, and is indeed "obscene."

Figure 2 shows the situation twenty years later. In this case, the average total cost curve intercepts the demand curve at a point below marginal costs and also below where marginal cost intercepts the demand curve. The triangle $arc$ represents welfare losses due to underpricing electricity.

Because the heights of the average total cost curves in both figures reflect the embedded cost measure of fixed costs, the position of the average total cost curves are themselves the direct consequence of company and commission policies on depreciation schedules and, in the diagrams, reflect the subsidization of future customers by present customers. Depending on choices that can be made with regard to intertemporal allocation of new generation capacity plant, rates could be set so that the marginal cost curve follows the pattern of marginal cost equal to price equilibrium points, rather than move in the opposite direction, as it does under the present approach. In other words, throughout the life of the average total cost curve, it could be made to pass through, or close to, point $a$, the optimal price, rather than point $p$.

The basic argument of this paper is that the level of revenue requirement in any year should be viewed as the result of a conscious choice, and an attempt should be made to allocate costs over time through a method which best leads to the reassigning goals of efficiency, fairness, and adequacy. In a time of inflation, this intertemporal cost allocation question is at least as important as interclass cost allocation in any given period.

The conventional approach evolved in a nonstationary time. In the absence of inflation, this approach spreads costs over the life of assets in a way not significantly different from the pattern of marginal costs, especially when plants of different vintage are involved. The advent of inflation has caused costs to become heavily front-loaded. The proposal described below removes the distorting effects of inflation and provides once again the time path of payments in real terms which would have existed had there been no inflation. This is a first step. The second step is to use the tools for allocating ratebase over time in a manner that improves the traditional nonstationary time pattern.

In the examples given here I assume that the leveled carrying charge, which in the absence of inflation would spread the charges equally over the entire life of an asset, is the appropriate one to use for spreading the costs of a new base unit to utility customers over the life of the unit. I will, however, modify the standard leveled carrying charge so that the time pattern in a period of inflation spreads the costs of the new plant equally in real rather than in nominal terms.

The mechanics of the approach developed here can be applied to any carrying charge and its associated depreciation schedule. It should be emphasized that a particular carrying charge for any capital asset determines the depreciation schedule of that asset and, conversely, that any particular depreciation schedule determines the carrying charge. The approach developed here works on the depreciation schedule. This method is completely general in that, by explicitly confronting the effects of inflation on the depreciation schedule, the original noninflation-distorted carrying charge pattern is duplicated. Any pattern of payments over time can be generated by specifying an appropriate depreciation pattern.

The proposed approach originated at least twenty years ago in some working papers of William Vickrey of Columbia University. As far as I know, the first paper on this topic was published by Vickrey in 1972.1 Stewart Myers assumes the nonstationary method to be straight-line depreciation and demonstrates how the inflationary distortions can be removed from this pattern using a method similar to the one discussed below. Recently, Sally Hunt Streiter has published three articles in Public Utilities Fortnightly describing the applications and computations of an inflation-corrected carrying charge and ratebase assuming the optimal nonstationary method to be the leveled carrying charge and its associated depreciation or "capital recovery" schedule.2 Streiter's approach is mechanically different than the one developed here, but the results are identical. Her arguments for the benefits and even the necessity of correcting the front-loading of costs caused by inflation are thoroughly end well developed.

For present purposes, I will call the carrying charge and the depreciation schedule which result after the distorting effects of inflation are removed the "economic carrying charge"
and "economic depreciation." The latter is no more than the observed change in asset value from the beginning of a year to its end. In the absence of inflation, this economic depreciation will be the same as the conventional depreciation associated with the leveled carrying charge. In a time of inflation, economic depreciation will reflect the change in asset values associated with a carrying charge that is leveled in real terms as shown later in Table 7. This economic depreciation can be broken into two components: (1) the change in the value of the asset due to its physical wearing out as reflected in the real depreciation schedule and (2) the change in the asset value due to inflation. Taken together, these two components determine the change in the asset’s value over the year and hence its economic depreciation, as shown later in Table 5. The resulting annual carrying charge will be leveled in real terms and will increase in nominal terms by the rate of inflation in each year.

Table 1, Figure 3, and Figure 4 illustrate the basic characteristics of the economic carrying charge and contrast these with the traditional leveled carrying charge. If the traditional method were based on straight-line depreciation, the traditional approach graphs would show even more heavily front-loaded charges.

In a time of inflation, the stream of payments cannot be leveled in both nominal and real terms. The traditional carrying charge levels payments in nominal terms and therefore causes the payments to decline in real terms by the rate of inflation. In contrast, the economic carrying charge levels the payments in real terms and therefore causes them to increase by the expected rate of inflation in real terms.

In real terms, it is seen in Figure 3 that the stream of payments based on the traditional approach starts at a level determined by the anticipated rate of inflation and then declines in real terms over the life of the asset. This means that an asset priced in such a manner starts out expensive and becomes cheaper later in its life. When a new base plant is charged in this manner, customers in the initial years are overcharged, customers in the later years undercharged. In contrast, as depicted in Table 1 and Figure 4, the economic carrying charge starts at a level determined by the anticipated real rate of interest, is independent of the rate of inflation, and remains constant in real terms over the life of the plant.

When adding new plant in a time of inflation, the proposed approach gives a continuity such that the carrying charge for plants of different vintage is the same. There is no increase in revenue requirement caused by the replacement of an old plant by a similar new plant. This continuity is very important. It eliminates the problem of rate levels jumping when new plant is added. This characteristic can
Avoiding Rate Shock

be seen by examining Table 1. If one extended Table 1 to show additional years, and if it were assumed that a similar plant were added starting in the tenth year, then the first-year economic carrying charge on the new plant in year ten would be $26.78, or exactly the same as the last-year carrying charge for the old plant (as shown in row 3). After nine years of inflation at 9 percent, the same $100 plant will cost $217.19. The first-year charge on this plant is then .12334 x $217.19, which equals $26.78, the same as the tenth-year charge on the old plant.

If we also assume that the new plant introduced in year ten required several years to construct, it can be seen that, under the economic carrying charge method, the greatest cash flow generated from the old plant occurs during the years of construction of a new plant started in year ten.

It should be emphasized that what I call "economic depreciation" does not imply that more than the original cost is ultimately depreciated. The present value of the payments by ratepayers, the total amount depreciated, and the return to investors are identical to the currently nominal levelized method; only the time patterns are changed to eliminate the time path distortions caused by ignoring inflation.

The effect of applying the economic carrying charge and economic depreciation is to defer payments such that the time pattern of payments is the same that would have existed in a noninflationary situation. Ultimately, the present values must be the same because the deferred payments are added to the ratebase, where they grow at the company's growing rate of return. So long as the assumed discount rate is the same as the company's rate of return, the present values of the total payments under the traditional and under the economic depreciation rate-making approach are identical.

Phasing in a new capital asset by the use of economic depreciation and carrying charges can be thought of as providing investors with an automatic reinvestment plan. To the extent that payments are not made in cash in the initial years, they are added back to the ratebase and paid later. Under this approach, investors receive in cash the part of their return corresponding to the real interest rate plus real depreciation. The part of their return corresponding to the inflation rate is added back to the asset as a component of economic depreciation, where it continues to earn the rate of return. Table 5 later demonstrates this process.

From the equity investor's point of view, part of the return is being distributed in the form of cash, and part of the return is being distributed in the form of a capital gain.

A numerical example of this phenomenon is given below.

The computation of economic depreciation and the related economic carrying charge can be illustrated in three ways. The first method is more direct and, in its simplicity, illus-
trates the more subtle interrelationships between carrying charges, intertemporal allocation, and depreciation. The third method is simply an application of a conventional economic definition of depreciation as it is used in capital theory. In effect, the methods are identical. The different approaches represent only different ways of viewing the same phenomenon. In all cases the sum of depreciation, both economic and conventional, equals to the original cost of the asset. Also in all cases, the present worth of all payments is exactly equal to the original investment.

Furthermore, in all cases the carrying charge payments equal the sum of the dollar returns on the asset values as the end of each year plus the depreciation used in the computation of the end-of-year asset values. This is true both for each year and over the life of the investment, so that over the entire period the total amount of depreciation plus the total dollar return equals the total carrying charge payments.

Asset Value Method

Using the first method, we determine the uninflated value of the asset at the end of each year, as illustrated in Table 2. We then find the economic depreciation by inflating each year's asset value and then simply subtract each year's asset value from that existing in the previous year. The resulting difference in asset values will be identical to the economic depreciation stream shown later in column 3 of Table 5. The sum of this economic depreciation and the rate of return times the beginning-of-year asset value will produce the appropriate economic carrying charge for that year.

This approach demonstrates the essence of economic depreciation because it shows that all we have done is apply the same inflationary expectations to the value of assets at the end of each year that are already applied in determining the nominal cost of capital and rate of return. In other words, the nominal cost of capital and rate of return computation already includes inflationary expectations. By correcting the error of applying the inflationary expectations to only one component, that is, the cost of capital, we remove the distortions caused by inflation, the extreme front-loading of charges, and the intertemporal allocation distortion.

A further example of this computation can be given by examining column 4, Table 2, and column 4, Table 5. The first column 4 shows the asset value at the end of each year, assuming a ten-year plant life and a nominal (and real) rate of interest of 5 percent. The second column 4 shows the asset value at the end of each year assuming a ten-year plant life, an economic carrying charge, a real rate of interest of 5 percent, and a nominal rate of interest of 4.5 percent.
implying an inflation rate of 9 percent.

Looking at the first column, we see that the asset value at the end of the first year is $92.05. In the absence of inflation, if inflation were 9 percent during this year, the asset value would be 9 percent more than $92.05, or $100.33, as shown in the second column. Over time, the asset values at the end of each year under economic depreciation will grow by the same rate of inflation included in the cost of capital. The change in value in the assets will then include both the increase in value due to inflation and the decrease in value as reflected in the normal depreciation pattern. These two factors, both represented by the change in asset value from year to year, are what we call economic depreciation. Clearly, this economic depreciation must sum to the same amount as the conventional total depreciation—the original cost of the investment.

**Economic Depreciation Method**

Another numerical example of the economic depreciation computation is shown in Table 5, which demonstrates the conversion of Table 2, the noninflation case, into its inflation counterpart. Column 1 of Table 5 shows the depreciation schedule taken from Table 2. This represents the depreciation schedules associated with a ten-year levelized carrying charge computation using a real interest rate of 5 percent and no inflation.

Consider the first year shown in Table 5. The real depreciation is $7.95, which after one year of inflation is equal to $8.62. Over the same year, the asset has increased in value from $100 to $109. Subtracting this increase in asset value from the depreciation gives $3.37 for economic depreciation in this year. This economic depreciation is then subtracted from the initial asset value, which because it is a negative in this case increases the asset value from $100 to $100.33. The second year’s economic depreciation is computed in a similar fashion by inflating the $100.33 by 9 percent and then subtracting this inflation-caused change in asset value of $9.03 from the inflated depreciation of $9.92, for a resulting economic depreciation figure of $0.89. Thus, the asset value at the end of the second year is $100.33 + $8.99 = $109.32. The economic depreciation for a total asset value of $109 is $9.44. Again, it is this economic depreciation of $9.44 plus the $14.30 return which when summed make the second-year economic carrying charge payment equal to $15.39.

**Present Value of Income Stream Method**

In economic theory, any machine or plant is valued at the present value of the future income stream it will generate. Its true depreciation is the change in asset value from year to year, such that the asset value in each year is simply present value of the remaining future income stream. Table 7 illustrates that this point of view will also result in end-of-year asset values and a pattern of economic depreciation identical to that found by applying the two methods already described. In this instance we start with the assumption that the plant’s output will have the same real value in each year of its life (noting that this first assumption may well warrant later modification). Assuming that we are dealing with a one-horse-shay type of plant, the income stream resulting from the plant’s output will be constant in real terms in each year of the plant’s life. If there is general inflation, then in nominal terms the value of this output will increase in each year by the rate of inflation. In other words, we will have a stream of income with the same pattern as the economic carrying charge. Moreover, if this stream of payments is constrained such that the present worth of all future payments must be equal to the cost of initial investment, then we will have exactly what we have called the economic carrying charge payments.

Examining Table 7, we see that the present worth of the future economic carrying charge payments at the time the plant comes on line is exactly equal to the cost of the plant, or $100. Looking at column 5, we see that after one year of operation the remaining nine years of economic carrying charges have a present life of $100.33. Therefore, after one year of operation, $100.33 is the economic value of the asset. Similarly, after two years of operation the future carrying charge payments have a present value of $99.44. Therefore, after two years the plant is worth $99.44. The change in asset value from year to year, which we have called economic depreciation, is therefore minus $3.53 in the first year and $.09 in the second year, and so on for each year of the plant’s life.

**The Investor’s View**

Turning to the investor’s view of all this we will now show that only the time patterns have been altered. Under the conventional inflation-distorted method shown in Table 3, investors would receive $19.51 in the first year. Under the economic carrying charge computation, investors would receive $16.12 in the first year, as shown in Table 4. The difference between these two payments is $3.39, or $1.27, or $5.39. If we look at the asset values at the end of the year (shown for year one in column 4, Table 3, and in column 4, Table 5), we see that the asset value at the end of the year with the economic carrying charge used is also exactly the $5.39 more than it would have been under the conventional treatment. This demonstrates that, under economic depreciation, the ratebase in a particular year increases by exactly
### Table 3. Levelized Carrying Charge with Inflation Included
Only in Interest Rate, End of Year Example

<table>
<thead>
<tr>
<th>Year</th>
<th>Return</th>
<th>Depreciation</th>
<th>Asset value at end of year</th>
<th>Carrying charge payments</th>
<th>Present worth of payments</th>
<th>Rate of return</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
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<td>5.06</td>
<td>94.94</td>
<td>19.51</td>
<td>17.05</td>
<td>0.1445</td>
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<td>89.15</td>
<td>22.53</td>
<td>14.89</td>
<td>0.1445</td>
</tr>
<tr>
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<td>82.52</td>
<td>19.51</td>
<td>13.01</td>
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</tr>
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<td>19.51</td>
<td>9.93</td>
<td>0.1445</td>
</tr>
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<td>19.51</td>
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</tr>
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<td>19.51</td>
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<td>19.51</td>
<td>6.63</td>
<td>0.1445</td>
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<td>17.05</td>
<td>19.51</td>
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</tr>
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<td>0</td>
<td>19.51</td>
<td>5.06</td>
<td>0.1445</td>
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<td>0</td>
<td>0</td>
<td>0</td>
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</tbody>
</table>

**Note:** Investment = $100; real rate of interest = 5 percent; nominal rate of interest = 14.45 percent; expected life of plant is ten years; and inflation = 9 percent.

### Table 4. Economic Depreciation and Economic Carrying Charge,
End of Year Example

<table>
<thead>
<tr>
<th>Year</th>
<th>Return</th>
<th>Economic depreciation</th>
<th>Economic carrying charge payments</th>
<th>Present worth of payments</th>
<th>Rate of return</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
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<td>14.12</td>
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<td>0.1445</td>
</tr>
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<td>0.1445</td>
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<td>0.1445</td>
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<td>0.1445</td>
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<td>6.52</td>
<td>19.93</td>
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<td>0.1445</td>
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</tr>
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</tbody>
</table>

**Note:** Investment = $100; real rate of interest = 5 percent; nominal rate of interest = 14.45 percent; inflation rate = 9 percent; expected life of plant is ten years.
### Table 5. Derivation of Economic Carrying Charge and Economic Depreciation, End of Year Example

<table>
<thead>
<tr>
<th>(1) Depreciation, Year no inflation</th>
<th>(2) Inflated depreciation</th>
<th>(3) Economic depreciation</th>
<th>(4) Asset value at end of year</th>
<th>(5) Dollar return</th>
<th>(6) Economic carrying charge payment</th>
<th>(7) Present worth of payments</th>
</tr>
</thead>
<tbody>
<tr>
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<td>9.92</td>
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<td>99.44</td>
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<td>2.41</td>
<td>97.04</td>
<td>14.37</td>
<td>16.77</td>
</tr>
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<td>100.00</td>
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</tr>
</tbody>
</table>

**Note:** Investment = $100; real rate of interest = 5 percent; expected life of plant is ten years; nominal rate of interest = cost of capital = 14.45 percent; and inflation rate is 9 percent.

### Table 5. Derivation of Economic Carrying Charge and Economic Depreciation, End of Year Example -- continued.

1. From column (2), Table I.
2. (1) times 1 + .09 per year.
3. Economic depreciation in any year is the change in the asset value due to inflation minus the inflation value of the real depreciation.
4. The asset value at the beginning of the year minus the economic depreciation shown in column (1). In real terms this column is identical to the asset value associated with the real depreciation shown in column (1).
5. 14.45 percent of the asset value at the beginning of the year (.1445 x (4) at t-1).
6. (3) + (5). This column is the end-of-year version of row (3) in Table 1.
7. (6) x (1 + .1445)\(^{-t}\). This column is the end-of-year version of row (2) in Table 1.
### Table 6. Economic Carrying Charge and Economic Depreciation as the Sum of Conventional Depreciation and a Deferred Account

<table>
<thead>
<tr>
<th>Year</th>
<th>Conventional depreciation, 9% inflation</th>
<th>Conventional asset value at end of year</th>
<th>Economic asset value at end of year</th>
<th>Economic carrying charge at end of year</th>
<th>Total dollars deferred at end of year</th>
<th>Annual charge in deferred account</th>
<th>Economic carrying charge payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
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<td>100.00</td>
<td>100.00</td>
<td>5.39</td>
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</tr>
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</tr>
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<td>82.52</td>
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<td>2.17</td>
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<td>100.00</td>
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<td>214.46</td>
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</table>

### Table 7. Economic Depreciation as the Annual Change in the Present Value of an Asset’s Future Income Stream

<table>
<thead>
<tr>
<th>Year</th>
<th>Economic depreciation</th>
<th>Economic asset value at end of year</th>
<th>Economic carrying charge at end of year</th>
<th>Present worth of payments at year 0</th>
<th>Sum of present worth of payments for years of life remaining</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>-.32</td>
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<td>25.80</td>
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<td>47.98</td>
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<td>100.00</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
the amount of the difference between the cash payment investors would have received under the conventional approach and the amount they now receive under the economic carrying charge approach.

In this case investors receive $5.39 less in cash, and the asset on which they are earning a return is worth $5.39 more at the same time. Because the amount the investor does not receive in cash is added back to the asset value (and rebase), where it continues to earn the going rate of return, the present value of the payments is the same under this approach as it is under the front-loaded approach.

It is quite possible that investors will require a risk premium when the repayment of capital is delayed, as it would be under economic depreciation. If there is some additional risk involved in the use of less front-loaded financing, it implies that the present costs of capital are imposing an implicit risk cost on the ratepayers involuntarily. The unfront-loaded debt financing merely makes the given amount of risk explicit and explicitly pays investors for bearing the risk. Any customer who is sufficiently risk-averse would be able to benefit by purchasing some of the debt and by explicitly being paid for bearing the risk; under the conventional system it would have been extracted without compensation by way of the front-loaded required payments from all customers.

Summary and Conclusions

Figures 5 and 6 illustrate the time pattern of rates (revenue requirement) faced by the ratepayer of a no-growth company with and without economic depreciation. It can be seen that revenue requirement and rates are highest when a new plant is added and subsequently decline until another new plant is needed, at which time the revenue requirement and the rates leap back to the highest level. The straight line in Figure 5 illustrates the rates and revenue requirement under a levelized real carrying charge and economic depreciation. In this case, the rates and the revenue requirements are constant. Whenever an old plant is replaced by a new plant, the first-year total payments on the new plant are exactly equal to the last-year payments on the old plant, so that the total revenue requirement is unchanged from year to year no matter what the vintage mixture of the plants.

The significance of this approach lies in rates not having to be increased when new similar plants are brought on line. Indeed, when the tax benefits are included in the analysis, the actual revenue requirement may decrease during the early years of a new plant edition, even in the absence of net system cost savings due to the addition of the new plant.

Figure 6 shows the comparison in nominal terms between

![Figure 5. Real Comparison of Revenue Requirement Over Time under Conventional (A) and Economic Carrying Charge (B) Approaches, No-Growth System](image)

![Figure 6. Nominal Comparison of Revenue Requirement Over Time under Conventional (A) and Economic Carrying Charge (B) Approaches, No-Growth System](image)
the conventional and economic depreciation approaches. In nominal dollars, assuming a significant rate of inflation, the discontinuity in revenue requirement caused by the conventional approach is greatly accentuated. The revenue requirements and the rates show very great sudden increases when new plants are brought on line.

One problem facing many companies is that the same inflation distortions arise both in the company's front-loaded charges of costs to customers and in the company's own front-loaded debt obligations to investors. Again, this is something entirely within the control of management. Some of the present difficult situations contain elements of self-fulfilling prophecy. Companies raise money by selling front-loaded debt instruments to investors and then claim that revenue recovery from customers must also be front-loaded in order to match the pattern of debt obligations. In both cases these time patterns are the result of management choices, or the result of management not examining or taking advantage of existing choices.

If a company wished to remove the inflation-caused front-loading of its conventional cost recovery approach, it could apply an economic carrying charge and have a cost recovery and revenue time path which would follow the change in marginal costs over time. Financing then could be structured so that the company's cash-flow obligations would have exactly the same time pattern as the anticipated income from the investment. Both time paths are flexible, and the existence of front-loading in one of them cannot be used as an excuse to continue front-loading of the other. For the equity investor, the proposed revenue stream, and indeed the method of economic depreciation, is simply another form of automatic reinvestment. For the bond holder, it is possible to construct a portfolio of zero coupon bonds which will have payout requirements exactly equal to the incoming cash flows resulting from economic depreciation. It is difficult to sympathize with companies that refuse to explore the potential of zero coupon bonds and the resulting flexibility of payout time paths in the face of cost obligations which are staggeringly front-loaded and of magnitudes which threaten the financial integrity of the entire utility.

The conclusion is that when one takes a different point of view, one can see an electric utility industry in a better financial state than it first appears to be, to the extent it has problems, many are fixable.

Notes


3. Note that setting \( \Delta = 0 \) gives the first-year cost of the plant.


5. If for tax or accounting reasons it is desirable to maintain the original depreciation schedule, the difference between the original and the desired depreciation pattern can be represented by a deferred income account to give the required results. This is illustrated in Table 6.


7. Stewart C. Myers, A. Lawrence Kolbe, and William B. Lye, 'Inflation and Rate of Return Regulation,' an MIT review draft paper dated April 1982.

New High Cost Plant

It is no secret that the electric utility industry is undergoing tremendous stress. Almost daily, newspapers carry stories about the current issues: excess capacity, anti-CWP legislation, rate shock, phase-lags, fuel adjustment clauses, incentive regulation, and even bankruptcy. Some say that if the 1970s were bad, wait until the 1980s are over.

I am not going to give a doom and gloom story about the electric utility industry. I will state, however, that the electric utility industry, its shareholders, its customers, and the people who regulate the industry face some significant challenges in the 1980s. I shall discuss one of these: the impact of new, high cost plant on established ratemaking principles.

"Rate shock" is a sudden, substantial increase in rates, unanticipated by the public. It may be experienced by a utility's customers when a major new facility enters commercial operation, but this is not the only type of rate shock. It is a recurrent phenomenon and has been dealt with, historically, in different fashions at different times. For example, during World War I, rapidly rising fuel prices produced substantial rate shocks. The response of regulatory commissions was the institution of the fuel clause, which became a regular feature of rates around 1918. In 1973-1974, the Arab oil embargo caused the rates of many oil-dependent utilities to rise by 50 percent within a short period. One regulatory response was to abolish the fuel clause, or at least in various fashions to levelize the rate fluctuations attributable to it. This scenario was repeated in 1979.

The most substantial contributing factor to the type of rate shock some utilities are experiencing today is the simultaneous entry into the rate base of (1) a large, expensive new generating plant and (2) the deferred carrying charges on the capital raised to finance the plant's construction. This sudden entry arises when a regulatory commission has not allowed current recovery of financing charges on construction capital, by allowing a cash return on construction work in progress (CWIP) in the rate base.

It is my belief that the best way to avoid most of this type of rate shock is to allow utilities to earn a cash return on all CWIP in their rate bases. This is in the long-term interests of ratepayers as well as utilities. When a commission has been pursuing a policy of short-term rate suppression, by either refusing to allow or allowing only partially a cash return on CWIP, the amount of truth often comes when the facility enters commercial operation. The rate consequences depend on individual circumstances. Fuel savings, for example, can offset or, in the most fortunate situations, even obviate the effect of the sudden large increase in the rate base. In other situations, however, a major increase is necessary to cover the additions to rate base.

Under traditional ratemaking techniques, at the time of commercial operation, the entire cost of the plant would be put into the rate base, and the utility would begin recovering a return on its investment plus expenses (operating expenses, depreciation, taxes, and so forth) associated with the plant. Under this technique, if the fuel savings are less than the capital-related revenue requirements, annual revenue requirements associated with a new plant are at their highest level in the early years of the plant's life. The annual capital charge associated with a plant decreases as the undepreciated book value of the plant decreases. This characteristic is often referred to as "front-end loading" of the revenue recovery. It has been suggested that front-end loaded rate increases give customers improper price signals about the true cost of supplying electric service. That conclusion has been reached on the assumption that front-end loaded rate increases result in pricing of service in excess of marginal cost during later years of the plant's life, after demand has grown and there is greater facility utilization. But sudden substantial increases in electric rates not only may be undesirable to ratepayers, but also may be politically impossible for the utility to implement. Even if it
were possible for utilities to raise rates substantially in an attempt to earn a full return on the underpriced investment, demand elasticities might preclude a utility from realizing full revenue recovery. Therein lies the dilemma.

In recognition of the adverse consequences of rate shock, various types of "phase-in," "trending," or "rate moderation" plans have begun to appear. Such plans began to be proposed in individual utility situations in 1982 and have so far appeared in fourteen states: California, Connecticut, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Missouri, New Mexico, New York, Pennsylvania, and South Carolina. There are five categories: (1) Some plans levelize rates by changing the timing of the recognition of the plant's cost in rates. Rate recognition begins before the plant goes on line and continues for a time afterward. There are two subtypes. "Trending" proposals begin rate base inclusion of a facility earlier than otherwise and end inclusion at a date later than the date commercial operation begins. Trending has been approved in Connecticut and is pending in with a very doubtful future, in Indiana. The second subtype is the "CWIP" schemes, recoup past allowances of a portion of CWIP in the rate base after a plant begins commercial operation. (2) Another plan is entry of the plant into the rate base in several stages, with all stages occurring after the plant has gone on line. (3) Some plans adjust the method of valuation. (4) Other plans defer the recovery of operating expenses. (5) There are plans which alter the method of depreciation.

At this point, I would like to describe the various phase-in proposals in greater detail and discuss some issues surrounding their implementation. Before doing so, let me emphasize that the views expressed in this paper are entirely my own and do not necessarily represent the views of the Edison Electric Institute, or any of its member companies. My survey and characterization of utilities' rate phase-in plans are inherently subjective; it is quite possible that some utilities or commissions may not agree with me in every detail. With that qualification, I will start my description with phase-in plans which levelize the effects of rate base inclusion.

Levelizing Plans

The two subtypes, trending and negative CWIP, have similar effects on revenue. The fundamental distinction between them is conceptual, the art of different rate-making philosophies.

Allowing a cash return on any CWIP in the rate base is actually a form of trending and certainly not a novel one. Trending, in the narrower sense in which I am using the term, is prospective in nature. It occurs when a commission first allows a cash return on some specific CWIP and provides simultaneously for a downward adjustment to the rate base for a period after the plant comes on line. This effectively extends and makes more level the "ramp" which a cash return on CWIP provides for costs associated with a plant.

Negative CWIP similarly levels the "ramp." However, it is a "give-back" sort of plan, retrospective in nature. The rationale is that because a commission has allowed a utility a cash return on CWIP in the past, it is appropriate to take cash away from a utility at some future date. The underlying thinking is that a cash return on CWIP is somehow an extraordinary, net-gain-proper regulatory policy; some proponents of negative CWIP often speak as though CWIP were a loan from customers. I do not agree. Utilities are peculiarly vulnerable to this retrospective decision making when they have been allowed to earn a cash return on only a small portion of their total CWIP. The amount of AWOC accumulated is great enough to require a substantial increase to put it all in the rate base. As I stated earlier, the sound way to avoid this would have been to allow a cash return on all CWIP.

In August 1983, United Illuminating Co. (UI) became the first utility in the country to have a rate base phase-in plan approved. It is a trending plan for UI's 17.5 percent interest in Seabrook No. 1. It arises out of Connecticut legislation on CWIP, approved in June 1983, which allows CWIP under very limited circumstances. The law requires deferral from inclusion in the rate base of an amount equal to the amount of CWIP previously in the rate base, after the plant goes on line, for a period equal to the period for which CWIP was included in the rate base. The Connecticut commission has just approved a comparable proposal for the Millstone 3 plant of Connecticut Light & Power Co.

A trending plan does not necessarily use CWIP. For example, in January 1983 the Indiana commission decided in principle to integrate the cost of Public Service Co. of Indiana's (PSI) two Marble Hill units gradually into rates by a "stair step" or trended route. This concept represented the commission's solution to the dilemma posed by its interpretation of Indiana statutes to preclude CWIP inclusion, on the one hand, and by its conviction that rates as set traditionally without CWIP do not merit federal constitutional minimum requirements, on the other hand.

In response to this order, PSI filed last July a "rate control plan." It proposed annual rate increases of 8 percent for six years, three years prior and three years subsequent to commercial operation of Marble Hill. The plan elicited considerable public criticism. The Indiana attorney general publicly characterized the plan as illegal and refused to
defend the commission against an unsuccessful attempt to enjoin the proceedings. In parte communications and press conferences expressed legislative displeasure, and the governor finally forced the commission to suspend the proceedings while a task force studied the situation. The latter's recommendations were so negative that they caused suspension of all work on Marble Hill. For all intents and purposes, the plan is dead.

Negative CWIP, unlike trending, has yet to be adopted by any commission. The concept originated with the Illinois commission's staff, which proposed such a plan in 1982 for Commonwealth Edison (CE) and Illinois Power (IP). CWIP previously included in the rate base for a plant would be removed from the rate base for corresponding periods after a plant came on line. AFUDC would be restored on excluded amounts; the rate base eventually would be increased by the amount of negative CWIP plus the restored AFUDC. The theoretical basis for the staff's position is the "capital investment recovery [Illinois model]." Staff justifies this as "more symmetrically passing back the benefits of lower costs realized through CWIP" to the customer who has paid rates based on CWIP. The commission did not adopt this plan, but it directed CE and IP to study it. CE, in its response, expressed reluctance to adopt a negative CWIP plan and suggested adjustments to depreciation as an alternative. IP, while not recommending any plan at this time, believes deferral of a portion of common equity return through an adjustment clause mechanism is the most promising alternative.

The negative CWIP concept has also been incorporated into recent legislation on CWIP in Illinois, which gives the commission authority to approve an offset.

In August 1982 the New York commission began an investigation of its own motion into rate-making principles for Long Island Lighting's Shoreham plant. At the commission's direction, LILCO submitted for consideration a "rate moderation plan," similar to the Illinois staff's proposal. Hearings on this and other proposals are under way before an administrative law judge.

Another negative CWIP plan has surfaced in Congress. A proposal of H.R. 6700, "Restructuring of Electric Industry" (1983), restricting the FERC's authority to include CWIP in the rate base would require the FERC to institute a negative CWIP plan if it found that such a plan was just and reasonable.

Deferred Entry Plans

Staggered entry phase-in plans have been approved by two state commissions, Illinois and New Mexico. Both are voluntary proposals by utilities.

Of these two, the Illinois case, which involved Iowa-Illinois Gas & Electric (IIGE), is especially interesting because it is the only rate base phase-in which has yet been fully litigated on its merits. The phase-in, which involves IIGE's part of the new coal-fired Louise plant, will be accomplished by an automatic adjustment clause. During a four-year deferral period, IIGE will defer part of the equity return, depreciation, and ICC amortization associated with Louise, giving its customers a credit to base rates by means of the adjustment clause. During a succeeding three-year amortization period, the deferred costs will be recouped by a charge adjustment.

The other proposal which has been accepted is for El Paso Electric's share of the Palo Verde No. 3 plant. The phase-in was embodied in a stipulation agreement approved by the New Mexico commission in September 1983. Half of El Paso's 200 Mw capacity at Palo Verde will be admitted to the rate base when it goes on line. The other half will be deferred, and AFUDC will continue to be accrued on it. The agreement calls the procedure a phase-in but leaves the timing of the latter phase(s) for future determination.

Three staggered-entry plans have been rejected by state commissions. In South Carolina, in February 1983, a proposal by the state's Consumer Advocate to delay entry of 50 percent of Duke Power's McGuire No. 2 unit into the rate base was rejected. This order is interesting because it probably should be interpreted to hold that rate base entry of a used and useful unit cannot be deferred beyond the point at which it becomes known and reasonable change to test year data. The two remaining rejections are based on policy grounds. In Idaho, the commission rejected a staff proposal to phase in the Kettle Falls and Colstrip No. 3 units of Washington Water Power Co. (WWP) over five years. The commission had made substantial downward adjustments to WWP's rate increase application, which made the plan "not necessary." It is interesting to note that Kettle Falls is a 42.5 Mw wood-waste plant; thus, it seems that small, renewable-resource powered plants are not immune to phase-in proposals. Colstrip, as the name indicates, is a large coal-fired plant.) The Kansas commission rejected a proposal to phase Sunflower Electric Cooperative's coal-fired Holcomb plant into the rate base. The reasons had to do with regulatory treatment of extreme excess capacity rather than with the phase-in concept itself. Other staggered entry phase-in proposals are listed below.

Detroit Edison Co.: a Michigan staff proposal for the Fermi No. 2 and the two Belle River units;

Iowa-Illinois Gas & Electric Co.: an Iowa application parallelizing the approved one in Illinois;

Iowa Power & Light Co.: also in Iowa, for IP&L's share of the Louise plant;

Kansas City Power & Light Co.: in Kansas and Missouri, for the Wolf Creek plant;
Individual circumstances. Two of the three plans of which EEI is aware depend on unique circumstances of this sort. I mentioned earlier EEI's proposed rate base phase-in of the Callaway plant, which UE filed in Illinois and Missouri on February 15, 1983. This plan also includes two adjustments to operating expenses. Under a settlement of a UE lawsuit against Westinghouse, UE is receiving cash and services over a thirty-year period ending in 2010. These payments will have aggregated around $116 million by Callaway's in-service date. UE proposes to amortize this credit balance over two years. UE will also amortize construction-related, accumulated deferred income taxes over three years.

Two Louisiana utilities, Louisiana Power & Light Co. (LPAL) and New Orleans Public Service Inc. (NOPSI), filed general rate cases with the Louisiana commission in January 1983. The filings, which sought to recoup the companies' costs associated with the Grand Gulf nuclear plant, included plans to defer operating expenses resulting from passage of purchased power costs for electricity from the new plant under a FERC wholesale rate. LPAL and NOPSI are both operating subsidiaries of Middle South Utilities, and the Grand Gulf plant is owned by a generating subsidiary of Middle South. The companies' plans proposed to defer for four years portions of the purchased power costs. After a break-even point is reached, accumulated deferrals would be recouped over five years. Due to a delay in the commercial operation date of Grand Gulf, the commission did not act on these plans in its recent rate case orders for LPAL and NOPSI. In effect, action has been deferred.

In August 1983, Pennsylvania Power and Light Co. (PP&L) received approval of a trended budget billing plan to moderate the effect on ratepayers of the Susquehanna No. 1 unit. This procedure will phase in the increase in rates resulting from the unit so that full recovery will occur by December 1984. All PP&L customers will be eligible for budget billing except temporary, seasonal, or speculative customers. It should be noted that PP&L proposes to treat Susquehanna No. 2 differently, by staggered entry, as I mentioned earlier.

Deferred Depreciation Plans

Two types of phase-in plans depart from traditional straight-line depreciation for ratemaking purposes. One extends the depreciable life of the plant from, say, thirty to forty years. However, this type of altered depreciation does not have a substantial effect on rate level. A more widely used method involves taking less depreciation during the early years and more in later years. As a result, the utility realizes a larger return on its investment in earlier years and a smaller return in later years than under traditional ratemaking procedures.
Depreciation proposals have been made in Illinois, Missouri, and Pennsylvania. All three are utility initiatives. I have already mentioned CVE’s plan in Illinois, which is a counterpart to the staff’s negative CWIP plan. Another, made in both Illinois and Missouri, is part of UE’s comprehensive rate moderation plan for the Callaway plant. It proposes substituting units-of-production depreciation for straight-line depreciation over the first three years of Callaway’s operation. UE estimates that its depreciation expense between 1985 and 1986 will decrease by about $49 million if this plan is adopted.

PP&L is the originator of the Pennsylvania proposal, which it advanced, along with its budget billing plan to ease the effect of Susquehanna No. 1 on its ratepayers. In August 1982 the Pennsylvania commission approved a mechanism allowing PP&L to utilize a sliding fund method to depreciate Susquehanna No. 1 for the first ten years of operation, then convert to straight-line for the remaining life. Under this concept, total capital costs for ratemaking purposes will be continued at the same amount, until undepreciated plant balance equals what it would have been under straight-line. Thereafter, depreciation will convert to what it would have been under straight-line, with depreciation expenses and return calculated in the usual manner.

Other Methods

In addition to the five already discussed, there are other approaches which can be used to supplement rate moderation plans. One approach involves proposed discounts from standard rates for industrial customers to improve or maintain the local economy and to prevent the loss of sales due to price elasticity. The discounts result in prices below the standard rates but above marginal costs.

In January 1984 rate case order for Public Service Co. of New Hampshire (PSNH), the commission allowed the adoption of a special industrial contract policy whereby all additional load above 300 MW for new and existing industrial customers will be discounted. This policy is intended to mitigate the short-term rate effect of Seabrook on the company’s sales and the state’s economy and to encourage additional sales which would not have occurred but for the existence of the discounts, which works to the benefit of all customers.

My department has found that there are at least eleven investor-owned electric utilities with approved or proposed rates offering discounts to new or existing customers that increase kilowatt-hour use, employment levels, or capital expenditures. Seven companies have received approval for experimental rates, which apply to large industrial customers, but several are available to commercial or irrigation customers. In some instances, discounts have been proposed exclusively for residential customers. At least twenty-three other companies were considering economic development or incentive rates, according to a survey conducted by the EEI Rate Research Committee in the summer of 1983. The survey is being updated.

As demand growth has slowed or even declined, a number of electric utilities have found that they have uncommitted capacity available in the short run. Any sales at prices above short-run variable costs for kilowatt-hours produced from uncommitted capacity provide a contribution to fixed costs. Quite clearly, available capacity is an incentive to increase sales.

Economic development is another reason to offer incentive rates. Every utility wants a strong economic base in its service territory. If high electric rates have been a barrier to industrial expansion, selective reductions may assist in the development of new industry.

Summary and Conclusions

To sum up, among companies with large construction programs relative to their existing assets, a majority is contemplating some form of rate moderation of capital costs by spreading the costs over a longer period (or over different periods) than under traditional ratemaking techniques. The spreading can be accomplished by collecting costs earlier than the in-service date or by deferring the collection of costs to later periods.

Utilities confronted cash shortages would most likely prefer a trending approach to provide cash prior to the in-service date. If cash revenue is not a critical issue, a utility could defer rate increases until after the in-service date. Any rate moderation plan eventually adopted should seek to balance the interests of all parties affected. This involves minilizing, to the extent practicable, the transfer of risk to the utility so that its financial health is not compromised. However, it is also desirable to minimize the rate effect on customers.

Finally, some utilities are attempting to mitigate the problem of rate shock by offering incentive rates. Their objectives are to attract new customers, increase existing customer usage, encourage area-wide economic development, and increase electricity market share.
This paper presents an actual case history of a South Dakota utility regarding construction of a baseload plant. When it came on line it substantially increased rates, placed the utility in an excess capacity situation, generated significant consumer response, and required the commission to develop a positive solution to the problem.

When the Coyote plant, a baseload coal-fired generating unit, came on line in May 1981, the South Dakota commission was put in the position of granting the largest rate increases to the participating electric utilities in the entire history of the commission. Even more disturbing, addition of the Coyote plant to the system of each of the participating South Dakota utilities created excess capacity on these systems. Even though the rates implemented when Coyote went on line reflected a disallowance of the common equity return on that portion of each utility's excess capacity, the rate increases were still extremely large.

In the case of Northwestern Public Service Company, whose electric operations are confined to South Dakota, the rate situation was the most acute. Northwestern's electric rates were the highest in the state, and the customer outcry was considerable. The fact that the company agreed to a restrictive rate increase moratorium, limiting the amount Northwestern could even request for four and one-half years, did not placate the ratepayers, who considered the company's current rates excessive. Against this background, the commission decided to investigate rate designs to see whether innovations could alleviate the burden faced by consumers.

Of course, many electric utilities across the nation are experiencing the twin problems of underutilized production capacity and low load factors. The South Dakota commission is taking an approach which we feel could be beneficial in other jurisdictions struggling with these difficulties.

If we lived in the best of all possible worlds, electric companies would experience high load factors, no underutilized production capacity, optimal (with respect to cost of production and efficiency) production plant mix, and clear and correct foresight as to demand and energy growth and fuel construction cost. Unfortunately, we do not live in such a world.

Load factors are an ever-present problem. Customer responses to seasonal changes in temperature may adversely affect load. Summer peaking systems produce the greatest extremes, and since there are very few alternative cooling sources, these systems are extremely difficult to control. Winter peaking systems also suffer fluctuations but appear to be easier to control. Part of the load factor problem is nonsynchronization of customer class peaks. If commercial and industrial peak coincidentally with residential, then there is the risk of overload; if different customer classes peak at different times, load can be decreased.

Consumption of electricity tends to change gradually over time, whereas production capacity is added or removed in large units and requires substantial load time to construct. Production plant additions are determined, to a large degree, on the basis of load forecasts. The matching of production capability to demand is a function of the validity of the forecasts. Over the past ten to fifteen years, most electric utilities, including those in South Dakota, have consistently overestimated their load growth. Since construction projects tend to be based on forecasts, when electric utilities overestimate load growth and build capacity to satisfy that load, they have created underutilized production capacity.

Excess production capacity has been a dilemma for both companies and regulatory commissions. On the one hand, in rate relief applications the company is faced with the possibility of having its excess capacity removed from the ratebase. The result could be harmful effects to the company's stockholders and to the company's ability to acquire external funds. On the other hand, if excess capacity remains in the ratebase, the company's ratepayers may suffer. In sum, underutilized production capacity has a detrimental effect on the company, its stockholders, and its ratepayers.

Given the current state of the electric utility industry in South Dakota, the commission has adopted several goals with respect to electric company regulation. First, we would...
like our electric companies to implement procedures which would enable their load factors to increase. Second, we would like for the companies to be able to control load growth effectively. Third, for those companies with excess production capacity, we would like to see economically sound procedures developed which will enable them to utilize that excess production capacity.

To achieve these objectives, we have considered various alternatives. One technique is load control procedures, which may have substantial benefits but also may have limitations. Load control procedures normally do not address systems with underutilized capacity. They may tend to shift load rather than actually control it. They may not stimulate usage in off-peak hours and, therefore, may not effectively increase load factor. Finally, we found that customers who could benefit the system most by the use of load control techniques may not participate in the program.

Another technique we have considered involves modification of a company's rate design. This is a possible way to control growth in peak demand and to stimulate usage. There are several problems. First, restrictive rates may not control peak demand, especially in summer peaking systems, and may cause needle-poking. Second, promotional rates designed for particular customer classes, such as large industrial users, may be considered unfair by other customers. Third, promotional rates across all customer classes may not only cause utilization of excess capacity, but also may force the utility into an unnecessary and costly construction program.

A third approach appears to be quite effective: a combination of load control and rate design with respect to marginal cost analysis. This seems beneficial in alleviating the problem of excess capacity and low load. In addition, it appears that there are beneficial economic externalities associated with this approach.

**Price Elasticity in Marginal Cost Analysis**

The procedure that we have found effective consists of seven steps.1 (1) A detailed analysis of the company's cost of service is made to ensure that costs were properly allocated to customer classes. (2) A customer class risk analysis verifies that returns to each reflected its risk. (3) A detailed econometric analysis determines the price elasticity of each customer class and for subclasses within certain customer classes. (4) An analysis is made of the marginal cost of producing a unit additional kilowatt-hour of energy. (5) A simulation shows the effect of various possible rate designs on the company's load forecast. (6) Rates are designed with respect to the results of the previous steps. The analysis assumes the traditional principles of rate design: (1) full recovery of the company's revenue requirements; (2) efficiency; (3) equity; and (4) practicality.

This procedure was used at Northwestern Public Service Company, a gas distribution and electric company providing electric service exclusively in South Dakota. Several extraordinary circumstances faced by Northwestern influenced the structuring of the company's rates. First, Northwestern has excess capacity. The company's 1982 load forecast estimated peak load to exceed 300 Mw in 1982. The actual peak load in 1982 was 290 Mw, and production capacity was 312 Mw, based upon a recent forecast. A 15 percent net reserve capacity obligation results in a total firm capacity obligation of approximately 240 Mw and excess capacity of approximately 70 Mw.

Second, as a result of a settlement agreement entered into by Northwestern in April 1981, the company is restricted in the amount of any rate increase to which it may be entitled in filings made prior to October 31, 1985. Thus, the potential exists for a large rate increase being requested by the company after the expiration of the settlement agreement.

Third, Northwestern's rates are currently quite high.2 The company had proposed new rates based on test-year sales. If the elasticity of demand of its customers for electricity is high, then total sales by the company could be reduced to the extent that its revenue generated was below its revenue requirement.

**Customer Class Risk Considerations**

Rates of return by customer class for electric utilities are normally not the same for all customer classes. The basic justification is that risk differences exist between classes. Unanticipated changes in consumption represent risk. Company sales will vary over time to some extent due to long-term growth and, to some extent, seasonal variation. To the extent that these changes are regular and predictable, they do not represent risk. Other factors, such as changes in customer base, changes in the economy, and changes in a plant's efficiency, could result in unanticipated changes in consumption of electricity and therefore contribute to risk.

In order to isolate the risk of each customer class, a time series analysis was conducted, that is, ordered observations of quantitative variables taken at successive points in time. Time, in terms of years, months, days, or hours, is simply a device that enables one to relate all phenomena to a set of common, stable reference points.

Two of the time series components, trend and seasonal, are regularly recurring changes. Isolation of these two components can be considered analogous to identifying expected
Customer class risks must be computed on a relative basis. The equation used is a form of the coefficient of variation, a measure of relative dispersion showing the scatter of the observation as a percentage of the average about which they are computed. In other words, the coefficient of variation takes a measure of dispersion, the standard deviation, and scales it by the average size of the observations, the mean, to obtain a relative comparison of dispersion.

The analysis indicated that the riskiest sales components of Northwestern are sales for resale, followed by sales to public authorities; the least risk are sales to residential and to commercial and industrial customers. The results of the customer class risk analysis were in accordance with the company's cost-of-service study.

**Econometric Models**

An econometric analysis was conducted to determine the price elasticity of demand in the consumer's budget classes. The basic idea of the economics of consumer demand is that the spending decisions of households and individuals are not merely the result of random impulses, but are governed by a more or less rational plan. Consumers are assumed to spend their money where they believe it will do them the most good, and thus every expenditure should be viewed as the result of competition for the consumer's income.

It follows from this view that an increase in income would enable the customer to spend more on every commodity. How much will be spent on each commodity will depend on the utility of that commodity to the individual. The utility of a good or service means the ability of that commodity to satisfy human wants. Another important implication is that an increase in the price of one product will generally lead to a decrease in the quantity purchased of that product, because the product is now less able to compete with other uses of the consumer's income.

The most important determinants of consumers' purchases of goods and services are income and prices. Income acts as a general constraint on consumer expenditures, and its influence is discernible in nearly every product. From the overwhelming majority of products as income rises, in contrast, the price of the commodity generally has an inverse effect on the level of consumption of the commodity being considered, and this effect has been demonstrated in the case of many commodities; that is, as price increases, the quantity demanded decreases. Also, in certain cases it has been established that the quantity bought of

**Utilizing Excess Capacity**

A particular commodity is influenced by the price of another commodity. Certain products, such as electric service, are bought not only by households but also by business firms and similar entities. The economic theory of the purchases of firms is similar to the purchase of commodities by individuals and households. Generally speaking, the purchases of business firms are related to a firm's production processes, this term being interpreted in the widest sense to include distribution, marketing, and finance. Businesses decide on the quantities they buy of all goods and services on the basis of the contribution these goods and services can make to net profit, which plays the same role in their decision as utility does in the case of households. In the case of firms, it is also true that an increase in the price of a product will generally lead to a reduction of the quantity bought since the price increase, everything else equal, directly reduces the firm's net profit. Ideally, one would measure the activity of business firms by the gross national product of the private sector, but this is not always available on the state basis. As a surrogate, aggregate personal income sometimes is used. This plays much the same role in the total purchases of business firms as it does in the total purchases of households. This is so because an increase in total income can be identified, at least approximately, with an increase in total output. An increase in the aggregate output of business firms will generally lead to an increase in total income, which in turn will generally lead to an increase in the quantity bought of all or most goods and services.

A convenient way of expressing the influence of prices and consumption is through the concept of price elasticity, which is defined as follows: The price elasticity of demand is approximately the percentage change in quantity demanded of a good or service associated with a one percent change in the relative price of the good concerned, income and all the remaining constant. The relative price is the price in relation to the price of all goods and services. Thus, if a price increase of one percent results in a 0.5 percent reduction in the quantity consumed, then the price elasticity is said to equal negative 0.5.

The principal way to estimate price elasticities of demand is through econometrics, the combined use of economic theory, statistical techniques, and empirical data. The estimation of price elasticities is one of the best developed branches of econometrics. An essential ingredient in the availability of data for periods during which income and prices have actually changed. In econometrics, the reason for unsatisfactory estimation results is usually a lack of independent variation in the underlying data. Since income, relative prices, and other variables affect the demand for
a particular product, it is not sufficient to look at various time series in isolation. Multiple regression analysis provides a means to disentangle the effects of the different variables.

Using economic theory, one hypothesizes which variables have a causal relationship to the quantity demanded. The variable specification must be suitable for estimation from actual data and must be relevant to the specific data set. Then the mathematical form of the model is selected. Many functional forms can be considered, but experience on balance favors the multiplicative, or log-log, form of isolating elasticity of demand. That is, the logarithms of the dependent variable are linearly related to the logarithms of explanatory variables. The additive form may be used for forecasting values. Once the variable specification and functional form are hypothesized, multiple regression analysis is used to estimate the elasticity coefficients. Statistical testing is then conducted to validate the model estimates.

Both multiplicative and additive econometric models were developed in the analysis. The multiplicative model's necessity to calculate the price elasticity of demand for the customer classes. Calculation of price elasticity of demand assumes that the values of all independent variables, except price, are constant. In the process of developing rates for the company, it was important to test the effect of any new rates on energy sales since price per kWh times the number of kWh sold equals total revenue. If the effect of a proposed rate structure is rapid growth in sales, then the company may be faced with undercapacity in the near future. If the effect of a proposed rate structure is a reduction in sales, then the company may not realize its revenue requirement.

The most likely price elasticity of the residential class was calculated to be .467. The 95 percent confidence interval for this price elasticity of demand for residential customers was -.8725 to -.0632. The econometric models calculate a point estimate, or most likely value, for each of the parameters of the model. Since the data used were only a sample of all possible observations, the calculated point estimates were only best-guess estimates of the actual values. The actual price elasticity most likely is not .467 for the residential class. The econometric modeling procedure takes this variability into account by providing a range wherein the true value may lie. The 95 percent confidence interval means that we are 95 percent sure the true price elasticity of demand for the residential class is between -.8725 and .0632. Conversely, there is a 5 percent chance the price elasticity of demand is less than .8725 or greater than .0632.

For the commercial and industrial class, the most likely price elasticity was calculated to be .0954. For this class, Utilizing Excess Capacity

Based upon the analysis, we can be at least 95 percent confident that the true price elasticity is between -.3.31 and zero.

Based upon the results of the econometric analysis, one can conclude that Northwestern's various customer classes do in fact react to price changes. All factors remaining constant, the company can expect the quantity demanded to be inversely related to changes in price.

Marginal Cost Analysis

Marginal cost is the cost of producing one extra unit of output. There are two important considerations in the marginal cost analysis. First, Northwestern currently has excess production capacity. Second, the rates proposed by the company were designed to generate its revenue requirement based on its pro forma level of kWh sales--725,746,560. At this level of output, under its proposed rates, the company would generate its revenue requirement. All costs of service are covered at this level of output. Since its cost of production has already been covered and it currently has excess capacity, if the company could sell one additional kWh the contribution to profit of that additional unit would be quite large. In this situation, the marginal cost would be the fuel cost associated with the next unit brought into production that would provide the additional kWh. It was determined that the additional cost would be approximately 1.5 cents.

Simulation Analysis

An analysis was then conducted to determine the effect of various rate structures on Northwestern's peak load and on its energy sales and revenue requirement. Load and energy sales forecasts were made on the basis of the company's actual customer mix. The econometric models were used to calculate a point estimate and 95 percent confidence limits based on the econometric analysis.

From the customer class load and energy sales forecasts, total energy sales forecasts for various usage scenarios were calculated. These ranged from worst case residential and worst case commercial and industrial to best case residential and best case commercial and industrial. These scenarios were compared to the company's total energy sales forecast. In all possible scenarios, by 1985 the company would be better off modifying its rate design to reflect price elasticities than it would be doing business as usual.
Peak load forecasts for the various usage scenarios were then calculated based upon the total energy sales forecast for the scenarios and relationships determined in the company’s load forecast. Excess capacity was then calculated for each load forecast scenario. The load forecast for 1994 estimates 35 Mw of excess capacity. Under the worst case both for residential and for commercial and industrial sales, by 1994 the company will only have 2 Mw of excess capacity. Under the best case for both residential and commercial and industrial sales, the company will experience a negative 5 Mw of excess capacity in 1991. In sum, if the best case situation occurs with respect to customer response to price changes, then the company could be in a negative firm capacity requirement situation by 1991. This, in turn, would require a costly construction program.

The final step of the simulation analysis was to calculate the company gain or loss based upon the various possible scenarios including the forecasts made and the test-year results. This stage of the analysis indicated that the company could expect to gain between $55,000 and $3 million above its business-as-usual revenue.

Load Control

Under best case conditions, the company will eliminate excess capacity by 1990; under worst case conditions, by 1994. Both these periods are substantially earlier than the company’s estimate. Rates based on the econometric analysis could, therefore, force the company to begin constructing additional capacity in the near future. Given this possibility, the load should be prepared to implement load control procedures no later than the end of 1984.

Since Northwestern has had no experience in load control techniques and has conducted no research into the various methods available, it was recommended that the company commences an immediate review of procedures which would be beneficial to the system. In the event it could identify those superior to others used by electric companies in South Dakota, the company should implement these load control procedures.

Rate Structure

Given the results of the econometric analysis, the simulation analysis, the company’s excess capacity, and its low marginal cost of production, with minor exceptions the proposed rate structure was designed to stimulate sales. The analysis suggested significant changes in the residential rate. Approximately 25 percent of Northwestern’s customers use less than 2000 kWh per month. This proportion is much higher than for the state as a whole. Given the elasticity of demand for small users, it was recommended that the rate be reduced from 8 cents per kWh to 7.2 cents per kWh. Considering the elasticity of demand for middle-sized residential users, the recommendation for this class was to extend the initial block from 500 kWh to 750 kWh with a minor overall rate reduction. The large user block was proposed to be maintained at one mill over its current level. In addition, certain heating rates have been proposed to stimulate the sale of energy for that purpose.

Optional rates were designed for commercial and industrial customer classifications to stimulate energy usage. By increasing energy usage by at least 10 percent over the previous year, a customer would receive, under the staff proposal, a 13 percent reduction in total cost. In the second year, a company would receive a strong incentive to increase energy usage by at least 10 percent over the previous year, they would receive a 20 percent reduction in rates. This option was considered to have a strong incentive on the company to reduce its additions; the company would be able to utilize some of its excess capacity and increase low marginal cost energy sales.

New customer incentive rates for commercial and industrial users were proposed. The marginal cost to the company of producing additional energy is quite low. One possible way of increasing energy sales is to add customers. Therefore, any new commercial and industrial customers locating in the company’s service area receive a flat reduction in all rates of 20 percent for five years.

Rate structures on Northwestern’s other groups were not proposed to be restructured. Elasticity of demand characteristics in existing rate structures of the other groups indicated that restructuring was not warranted at this time.

In light of the somewhat experimental nature of the rate design which resulted from this analysis, one additional feature was proposed. This was referred to as a windfall profit rider, a device which enables the company to recover any revenue shortfall by adding a surcharge to rates and to refund any windfall by a reduction of rates.

Summary

It was determined that the problems of excess capacity and low load factors can be mitigated by proper statistical and economic analysis and by rate design based on load control and price elasticity analysis. A rate design based on this analysis, in conjunction with marginal cost analysis, provides an opportunity for the company to utilize its excess capacity. It enables the company to recover its cost of service through the use of a safety net if worst-case customer reaction occurs. The approach signals the company’s customers that they will benefit by increased usage which, in turn, tends to stimulate usage. It was determined that uneconomic load growth could
be prevented by the use of load control techniques in conjunction with proper pricing as established by economic and statistical analysis. As a side effect of this procedure, it is anticipated that economic activity can be stimulated in Northwestern's service area by promoting new business growth in an efficient and orderly manner.

The South Dakota commission feels this overall proposal is consistent with the need to alleviate economic shock and to offset the effects of conservation, inflation, and load growth which has plagued the utilities and consumers over the last five years. It is intended to be a progressive positive step in efficient utilization of our base load generating plants for the short term and to be mutually beneficial to both the utility and its customers. It would appear at least to be a possible solution to excess capacity, especially where marginal costs exist.

Notes

1. The study and analysis were done by Thomas Fish Associates Company, Suite D, 4405 Roland Road, Independence, Missouri 64055.

2. Current residential rates are: first 500 kwh, per kwh, .081; next 500 kwh, per kwh, .0731; over 1,000 kwh—summer (5/1-9/30) .073, winter (10/1-4/31) .047; customer charge $5.00 per month.

I am impressed with the creative approach adopted by the South Dakota commission, as described by Commissioner Kenneth Stoffel. My main reaction is that it is disturbing that the commission had to think of the idea and that there appears to be opposition to it from the utility.

I have decided that Miles Olwell's paper should be retitled "Depreciation without Inflation" or something similar. A problem I see with his approach is that it presumes a neutrality on the part of the utility between present and anticipated revenues. It has been my experience that, just because the present values of two streams of revenues for a company are the same, it is not necessarily the case that the company will find the deferred compensation equally attractive.

The only point I can add to David Owens' paper is that he implicitly assumes that new plant will go into the ratebase at some time. This is not always the case. It is necessary to consider questions of prudence, for example, in reviewing the ratemaking treatment of construction expenditures.
COMMENTS

William R. Ahern

Only with a regulated industry can one have a discussion of how to make customers pay for excess cost plants. A simple-minded ratepayer might ask: "Why should I pay for something I don't need or want, and worse, why should I pay for a plant that was supposed to cost one-tenth of the final cost?" These are good questions. They raise the issue of when a plant is "used and useful" and of when ratepayers should pay for it at all. But that would be a subject for another panel. The papers by Miles Bidwell, David Owens, and Kenneth Stoffenahn start with the premise that ratepayers should pay for the excess capacity. The issue is how to make those payments as palatable as possible or, as Bidwell states, as efficient, equitable, and adequate as possible.

In a polite way, Owens resents that utilities and regulators would not have rate shock problems if only they had allowed construction work in progress (CWIP) to be put into rates. This minimizes financing costs and results in lower amounts that need to be put into rates when the plant operates. This is not the place to rehash this one. I would just say that I find it very hardy to be able to tell legislators their constituents are not paying for a plant that is not operating.

Owens presents a very useful tour of what states are doing to cope with rate shock problems. All the responses and proposals spread out the costs of a costly plant, with some proposals spreading them out more than others. It clearly is easier to stay close to front loading costs in the tradi-

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tional manner when the plant in question actually results in fuel savings that will save ratepayers money over the long run. Phasing in ratebase amounts and rate moderation can be used to mitigate public outcry, and the rate at which to spread out the introduction of costs into rates is actually a "finger to the wind" exercise that utilities commissions might make. The entire weight of inertia lies with front-loaded full ratebase. The financial community especially is portrayed as becoming completely unversed if the traditional rate making is left too far behind. So, to keep a sensitive finger to the wind, a public utilities commission can put some costs into rates and watch the audience response meter for different audiences—the ratepayers, the legislature, the financiers, and so forth. Then the commission can let some time pass and then try some more. This incremental "finger to the wind" approach may seem modified, but it can actually be a sophisticated and risk minimizing way to put costly, excess plant into rates.

If a commission wants to be theoretically correct regardless of the audience response meters, then it would do well to study Bidwell's paper closely. It is a clear and cogent argument for changing the arbitrary way costly plants are currently depreciated. His proposal would result in more equity and efficiency, no doubt about it. His point that the current front loading of costs places a risk premium on ratepayers is a good one, especially with respect to nuclear plants. We have seen a number of such plants already fail to stay in operation for a reasonable useful life. But if one of these large investments goes out of operation in ten or fifteen years, it has already been mostly depreciated, and investors have recovered their money. The ratepayers are left with the risk of plant failure. This seems entirely unfair and is another good reason for altering depreciation schedules and improving intertemporal equity, and risk.

Both Stoffenahn and Owens raise the adequacy of incentive or promotional pricing for coping with excess generating capacity. They are both sensitive to the short-run versus long-run problem when considering rate discounts and promotional pricing designed to increase demand and lower average costs for all ratepayers. It would be a disaster for South Dakota to attract new industry with promotional electricity rates only to see demand increase to the point at which a new and costly coal plant is needed and rates for everyone increase dramatically. The farmers would not be pleased. This is a difficult supplying act. Dealing with short-run excess generating capacity, Stoffenahn alludes to the goal of using the excess capacity soundly while trying at the same time to increase load factors and control load growth, all desirable goals. But what a complicated analytical task it seems to be to design rates and load control programs to optimize the system over time. Even with the help of
top consultants, those price elasticity studies seem suspicious. We are not the centralized French electricity utility working hand in hand with centralized industrial planning. Somehow, consumers' responses to rates have a way of getting away from us. Promotional pricing seems risky as it creates expectations which must eventually be dashed, that is, the promotional rates must expire when costs again go up. Regulatory systems have a difficult time being nimble and flexible once expectations are planted. If the South Dakota farmers were asked, I would guess they would first say they do not want to pay for excess capacity at all. Second, I would guess they would say they are willing to pay for it as long as they are guaranteed the benefits later, when it is actually needed. Banking excess capacity with its short-run costs also puts pressure on the regulatory commission to keep rates down. Stofferahn said at the conference that his commission had not adopted the consultants' recommendations; my guess would be that is still the case.

COMMMENTS

Glenn B. Thorsen

Phase-in and rate shock are not new phenomena. In 1972 Wisconsin Electric Power Company was considering a type of phase-in for its Point Beach Unit #2. This was not due to rate shock caused by the unit's cost but due to delay in receiving a full power license from the Atomic Energy Commission (AEC), which has since been replaced by the Nuclear Regulatory Commission (NRC). Wisconsin Electric originally proposed putting 20 percent of the plant cost into the ratebase because it only had a 20 percent power license. It proposed continuing interest during construction (IDC), now allowance for funds used during construction (AFUDC), on the remaining 80 percent. Wisconsin Electric pointed out to the Public Service Commission of Wisconsin that Consumers Power, Commonwealth Edison, and Consolidated Edison had taken similar action for similar problems they had previously experienced. As it turned out, Wisconsin Electric's full power license was granted by the AEC a short time after the above proposal was made, and the plant went into service.

Rate shock, of course, occurred for many utility customers and people heating homes with oil when the Arab oil embargo was imposed.

Phase-in has been taking place through CWIP in the ratebase or through return in some rate jurisdictions for years. The latter is the case in Wisconsin, where required return on the ratebase is adjusted for CWIP. In my opinion, CWIP in the ratebase is the best form of phase-in available and goes a long way in reducing one-time rate shock.
Miles Bidwell's paper presented the interesting proposition of economic depreciation and the change in an asset's value due to inflation less the inflated value of real depreciation. Bidwell's example used a ten-year life, and while ten years may be fine for illustrative purposes, generating plants which cause rate shock have 30- to 40-year lives. Using a 30-year life in Bidwell's example would result in the asset value at end of year exceeding the original cost of the asset for approximately half the asset's life. Thirty years is a long time. Many changes can and will take place in the industry over that period. I am concerned about delaying depreciation expense as Bidwell's method would do and then have a change take place at the state commission; the succeeding commission might not allow recovery of depreciation through rates that under present accounting methods would have been taken. At the opening session of this conference, Paul Levy, Chairman, Massachusetts Department of Public Utilities, indicated he felt that depreciation reserve deficiencies in the telephone industry should possibly be written off without rate recovery, so the concern I express is real.

It is my opinion that investors would perceive more risk under Bidwell's approach as compared to more conventional capital recovery methods. Other problems I see with this method could result from interim additions and retirements of substantial amounts for such things as acid rain and NRC mandated changes at nuclear plants. In addition, states looking for additional tax dollars could well look at increased book investment caused by inflation and Bidwell's approach to squeeze higher tax payment from utilities and, in turn, their customers.

I agree with David Owens's thoughts on inclusion of CIWP in the ratebase. However, total inclusion of CIWP may not be necessary in all cases. Financial need (but not financial need as the FERC once defined it) should also be considered. Owens gave a very good summary of the various phase-in programs currently proposed.

I agree with Kenneth Stoffershahn that the problem of excess capacity, if such is determined to exist, can be somewhat mitigated through pricing and load control. I do not have a formula for determining when excess capacity exists for individual companies or how to handle that excess capacity for ratemaking purposes. Many different approaches have been suggested. Some have actually been implemented. Optimal rates to stimulate energy usage have been suggested as have incentive rates for new commercial and industrial customers. In the case of Northwestern Public Service Company, incentive rates with a 20 percent discount for five years were suggested. This type of discount may or may not work. If electric rates of the utility are already much higher than those of another utility in competition for new load, and if energy costs are significant for potential new customers, a 20 percent discount may fail to attract the new customers.

Customers and potential customers must be fully apprised of the current situation with respect to incentive utility rates and fully informed about the rates terminating in the future so that their investment decisions take this into consideration.

In summary, utilities faced with large dollar plant additions coming on line should "get their house in order" well in advance of the estimated in-service date of the new plant. This is necessary so as not to affect any increases revenue requirements by the need also to increase rates for depreciation or write off deferred items or other large ticket items which could have been included in rates prior to the plant in-service date.
Part Eight:
THE FRENCH EXPERIENCE WITH NUCLEAR POWER

J. P. Bener

Having been kept out of the Manhattan Project, France's nuclear industry after World War II was far behind the U.S. and British industries. In fact, all nuclear expertise had to be built from nothing, with no outside help. For this reason, the French government in 1945 created the Commissariat à l'Energie Atomique (CEA), a government-owned organization in charge of developing the nuclear industry in France. In 1946, Electricité de France (EDF), a public utility in charge of generating and distributing electricity to the country, was created.

In 1947, the first French experimental nuclear reactor, ZOE, was built. In 1954, EDF began studying the possibility of generating electricity using natural uranium reactors of the type developed by the CEA to produce plutonium. In 1956, construction was begun on a series of commercial reactors of the UNGS type—gas cooled (CO₂), graphite-moderated, and using natural uranium. This type was chosen because France at that time did not have an industrial uranium enrichment facility.

In 1958, the CEA launched three plutonium-producing units in Marcoule. One of them, G3, which had an electricity generating capability of 40 Mw, became commercial in 1960 and still is operating. The EDF units launched in 1956 were built according to the schedule shown below.
A prototype 70 Mw reactor, moderated by heavy water and gas-cooled (CO₂), was started in July 1967. A projected 600 Mw unit was later canceled.

As early as 1953, the CEA started work on fast breeders projects, and EDF joined in those in 1960. This resulted in the construction of a 295 Mw demo plant, the Phenix LMfBR, which became operational in December 1973.

In 1960 EDF also became involved in light water reactor projects in conjunction with Belgium. Two pressurized water reactor plants were built—Sena-Chooz, 310 Mw PWR (4/67), and Semi-Thange, 870 Mw PWR (3/75). Due to the low cost of fossil fuel, it was decided in 1968 to halt the UNGG projects. However, to keep the nuclear program operating, it was decided in 1970 to launch an important light water reactor program (8,000 Mw in five years). This resulted in the purchase of a Westinghouse PWR building license by Framatome, the French vendor. EDF then started the construction of 900 Mw units (two in Fessenheim and four in Bugey).

In 1974, following the dramatic increase in fossil fuel prices, the French government decided to support and expand the EDF PWR program, which then was extended to the construction of 5,000 Mw per year. In 1975, a pending BWR project was canceled for economic and technical reasons; EDF wanted to standardize its plants and units and strengthen its expertise by concentrating on only one type of reactor.

A joint venture with Germany (RWE) and Italy (ENEL) led to the construction of a 1,200 Mw fast breeder (LMfBR), Creys-Malville, scheduled to be online in 1984.

In 1981, due to the recession and for political reasons (to satisfy elected officials who supported the anti-nuclear lobby), the French government decided to reduce the nuclear program for 1982 and 1983; only three units per year will be launched. This may be cut down to one or two units per year in the future, depending on the economic situation.

The Present Situation

At the end of 1983 the status of nuclear power plants in France was as follows:

<table>
<thead>
<tr>
<th>Operating units</th>
<th>Installed Mw</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 UNGG units</td>
<td>1,960 Mw</td>
</tr>
<tr>
<td>1 heavy water moderated/gas-cooled unit</td>
<td>70 Mw</td>
</tr>
<tr>
<td>1 LMfBR unit</td>
<td>233 Mw</td>
</tr>
<tr>
<td>28 PWR 900 Mw units</td>
<td>25,160 Mw</td>
</tr>
<tr>
<td><strong>Total operating Mw</strong></td>
<td><strong>29,433</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Units under construction</th>
<th>Installed Mw</th>
</tr>
</thead>
<tbody>
<tr>
<td>6 PWR 900 Mw units</td>
<td>5,320 Mw</td>
</tr>
<tr>
<td>17 PWR 1,300 Mw units</td>
<td>21,775 Mw</td>
</tr>
<tr>
<td>1LMfBR 1,200 Mw unit</td>
<td>1,200 Mw</td>
</tr>
<tr>
<td><strong>Total Mw under construction</strong></td>
<td><strong>28,295</strong></td>
</tr>
</tbody>
</table>

Projects on the 1984 program

| 2 PWR 1,300 units | 2,645 Mw |

By 1990, France will have a nuclear power generating capacity of about 58 Gw, which is the present capacity of the United States.

The following statistics for 1982 show the different methods for generating electricity and their percentages: 71 Twh (26.7%) generated by hydraulic plants; 91 Twh (34.6%) generated by fossil plants; and 103 Twh (38.7%) generated by nuclear plants. During the first quarter of 1983, 32 Twh were nuclear generated. By 1985, it is expected that 50 percent of French electricity will be nuclear; by 1990, it will increase to 70 percent. Appendix A gives a complete overview of the present French nuclear program.
Reasons for the Nuclear Option

In 1973, France's energy dependence rate was 75 percent; it will decrease to 54 percent by 1990. At that time, nuclear power will cover 30 percent of France's needs in energy and 70 percent of production of electricity. Energy independence is the major factor in the decision to expand nuclear power development, but economic considerations are also important. The costs given below per kwh of electricity generated by fossil and nuclear plants are specific to France, but their order of magnitude applies to other industrialized countries. These figures incorporate operating, capital, and fuel costs.

Based on 1983 French currency (one centime = 1/10 of a franc), corresponding costs are 34c/kwh (about 1.18¢ U.S./kwh) for nuclear plants. It would be irrelevant to compare the costs of fossil-fuel fired plants in France. Although fuel oil was the correct economic alternative in 1970, it is not economically feasible today due to the tremendous increase of this product on the French market. An "artificial" cost estimate would be approximately 40c/kwh, but, as previously stated, such a comparison is meaningless.

The role of fuel costs in these prices are as follows:
- 21.4 centimes (65 percent) for coal, and 5.5 centimes (25 percent) for nuclear fuel. Nuclear fuel accounts for only 25 percent of the total cost of electricity. As uranium itself accounts for 33 percent of the price of nuclear fuel for PWR reactors, it amounts to only 8 percent of the total price of electricity. Therefore, the nuclear option offers easy protection against a possible shortage in uranium supply. This remains a constant risk in the case of imported fuel. At this low cost, it is possible to build up a safety storage of natural uranium covering many years of operational needs.

A number of U.S. studies do not show the same significant difference in costs between fossil and nuclear electricity. This is due mainly to the fact that construction delays of nuclear units in the United States are about twice those experienced in France; this results in a considerable increase in investment costs.

There are also technological and ecological advantages of nuclear energy. The production of one kwh of nuclear electricity creates less pollution than the production of the same kwh by fossil plants. This takes into consideration the entire cycle from the coal mine, uranium mine, or oil drill to the actual produced electricity. Regardless of all that has been said or written derogatorily about nuclear waste and the hazard it represents, one thing is clear: Nuclear waste is less voluminous and more easily controlled than waste generated from other means of producing electricity.

Since the nuclear industry is subject to extensive precat-

Policy and Program of EDF

EDF, through a standardization policy resulting in contracts with vendors/manufacturers, has reduced industrial investment costs. For the construction of its fossil plants, EDF already had adopted a similar standardization policy. It consisted of launching, over a given period (seven to ten years), the construction of plants of the same power (100, 200, 250 Mw, 300 Mw, and so forth). A similar approach was used for nuclear power plants. Two levels of power (900 Mw from 1970 to 1982, 1,300 Mw after 1977) were chosen because they matched the stability requirements of the French network.

The Standardization Program

The main aspects of the standardization program are as follows. (1) With identical units, the only differences will result from site conditions (heat sink, contract services, protections, environment, cooling process, and so forth). The primary circuits and the turbine hall remain identical. (2) New and existing plants will be carried by all units belonging to similar series. (3) All units belonging to similar series will benefit from the same technical improvements, which are developed by increased experience from building and commissioning of similar units. (4) When possible, the same vendors will be used for all units or similar series.

Several main advantages result from this standardization program. Prior to operation, design and modification costs are lower than otherwise and industrial investments are optimized. Also, time is saved by reconducting design studies, improvement of manufacturing lines by the vendors, and construction and commissioning techniques due to rapid feedback.
During operation, plant availability is improved because defective equipment can be replaced immediately. There is immediate feedback on operating experience, and improvement of operating procedures is significant. Finally, a larger number of training simulators is significantly stronger, resulting in better training. All this leads to improved safety, and high-level planning for industrial products on a national basis helps avoid a shortage in basic material or equipment.

Site Identification and Construction

A long-term site identification policy that considered technical, social, and economic aspects was developed by EDF in conjunction with government authorities. The site-specific costs of a nuclear unit are essentially the average of the electricity transportation costs, building costs, and the costs of adapting the plant to the proposed site. In plant site selection there are two major considerations. The first involves effects on the environment due to disposal of waste water, radioactive/chemical wastes, and noise nuisance. These must be as low as possible. The second concerns the dimensions of the plant and the huge foreign labor force that must be gathered during the construction phase.

The issue of waste water disposal involves many studies of sea or river cooling, air cooling (the effect of cooling towers on the local area), wildlife, aquatic life, and so forth. The dispersion of radioactive wastes by surface waters also is studied. Architectural aspects also must be considered. For example, for coastal sites, areas with cliffs are preferred, as they make it easier to integrate the power plant into the landscape.

With all these parameters in mind, EDF drew up a list of 21 possible or potential sites. Draft projects for all of them were formulated, and some preliminary work was done (such as taking soil samples and studies of the substrates). Throughout these early stages, local government authorities are kept informed, and EDF issues a technical and economic feasibility report. If the government agrees with the report, a more in-depth project is developed. This takes into account local short- and medium-term needs and generates the necessary applications for all administrative authorizations required to build the power station. Essentially, two documents are issued: an intermediate safety and analysis report (ISAR) and an environmental impact report.

This is the method EDF has used for opening 21 sites in France. However, the process has not always been easy, and to keep the program on schedule and to obtain the needed authorizations in time, EDF has filled some sites with as many as four units (Gravelines has six sea water cooled units) despite antinuclear pressures.

The advantages of this method are lower building costs, better safety, more trained crews, time reduction in commissioning units, and improved work quality. The drawbacks are concentration of power in certain areas, significant organization requirements, and difficult management problems at such large sites. Nevertheless, the government strongly supported this method.

The Social Effects

EDF carefully studies the impact on the area or region of developing a huge construction site. Local government authorities are consulted about the additional facilities needed (housing, schools, communications, roads, and so forth), training of local construction personnel, and all vendors and companies involved with construction personnel. The vendors and companies involved are grouped into a consortium to coordinate all infrastructures (housing) and common activities (hiring and training of personnel).

From 40 to 60 percent of the civil labor force and 20 to 40 percent of the mechanics and electricians needed during the construction period are locally hired. In some cases, such as the Chinon B plant, these rates have reached 85 and 50 percent, respectively. This creates 600 to 800 jobs for a four-unit site. In planning for the postconstruction period, the government tries to maintain and develop this local employment by attracting to the area those industries which could use this manpower.

During construction, 36 percent of all salaries paid benefit local commercial activities. Construction of the plant also encourages the development of industries which might use the excess steam and heat generated at a later stage (such as greenhouses to grow vegetables in winter, aquaculture, and fish breeding).

Construction Experience

The original planning of a 900 Mw unit involves three phases. The first is civil work on the site, manufacture of equipment in the workshop, and beginning installation of this equipment. The estimated duration is 32 months. The second is installation of heavy equipment (that is, NSSS-turbine generator), estimated to require 12 months. The third is integrated commissioning tests before and after connection to the grid, leading to commercial operation. The estimated duration is 14 months. In sum, a total of 58 months (without float) is necessary to complete a 900 Mw unit. The site preparation time is not included in this estimate.
This schedule was not met for the completion of the first unit at each site; it was used more as a "motivation" schedule. At this point, the average time to complete a unit is 60 months, only two months above the theoretical schedule. The two-month gap is due essentially to unavoidable delays in the manufacture of heavy components.

The experience gained from one unit, especially on a four-unit site where the same personnel perform the same work four times before moving to another site, is highly beneficial. For example, the delay between Fessenheim units #1 and #2 was nine months, the same delay as between Bugy units #2 and #3. However, for more recent units such as Dampierre units #3 and #4, the delay was reduced to three months.

Presently, the average time needed to complete a PWR unit (900 Mw) in France is six years.

Operating Experience

The average operating time of the French units is higher than the average world time, as indicated below. By the end of 1983, EDF will have accumulated 78 reactor-years of experience.

<table>
<thead>
<tr>
<th>Year</th>
<th>French units</th>
<th>World avg.</th>
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</thead>
<tbody>
<tr>
<td>2d year</td>
<td>9,600 equivalent hours at full load</td>
<td>9,200</td>
</tr>
<tr>
<td>3d year</td>
<td>15,500</td>
<td>14,500</td>
</tr>
<tr>
<td>4th year</td>
<td>21,700</td>
<td>20,700</td>
</tr>
<tr>
<td>5th year</td>
<td>28,400</td>
<td>27,000</td>
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</table>

A tight liaison between the departments in charge of construction and those in charge of operation ensures that units under construction benefit from the experience of units already operating. For example, the backfitting work resulting from operating experience represents 100,000 engineer hours/year and only 2-3 percent of the total cost of the entire nuclear program. These costs would have been significantly higher in the absence of standardization. Quality of operation also is increased by the installation of training simulators in the operation areas and the improvement of maintenance procedures through the use of mocos and elaborate training programs.

These are the benefits of a standardization policy, and even the radiation exposure of personnel during outages is reduced significantly due to the experience accumulated.

The French nuclear program is expensive, but it already has paid off by increasing the safety and availability of nuclear plants. Keeping fossil-fuel fired plants out of operation for only a couple of hours already has resulted in a significant cut in generating costs.

To support this program, EDF will have hired 10,000 additional operations personnel between 1975 and 1985, personnel who have gone or will go through an extensive training program.

Prospects for the Future

The light water reactor (LWR) program, as well as the liquid metal-cooled fast breeder reactor (LMFBR) program, will continue to be developed. A new type of 1,300 Mw PWR reactor, the N4 type, presently is being developed. The first construction project should be approved in 1984 and will incorporate all experience learned from previous programs (reliability of components, technical progress in electronics and control systems, improved man/machine interface in the control room, and so forth). Commercial operation is expected between 1990 and 1995.

France now has more than twenty years of experience in the LMFBR field. Before the economic recession, this program seemed less urgent than PWR development. However, LMFBRs are the only answer to a future shortage of uranium, as they will produce much of the fuel remaining from PWRs (this type of reactor burns only .5 percent of the fissile uranium). What is left over is presently part of problematic nuclear wastes and could be reprocessed and used easily in fast breeders after the first load of plutonium is used.

As no other alternate source of energy has yet reached the industrial stage, the fast breeder is considered the future energy producer in France. As already mentioned, a 295 Mw demonstration plant has been operating since 1973, and a 1,200 Mw commercial unit will begin operating in 1984. The cost of electricity generated by LMFBR units should decrease to that of PWRs as soon as this option reaches the industrial stage at the end of this century. The construction of a fast breeder fuel reprocessing plant is another government-sponsored joint project between EDF and CEA.
### Nuclear PWR

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<th>Year</th>
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### French Nuclear Power

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Nuclear fast breeder

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MANAGING AND FINANCING NUCLEAR WASTE DISPOSAL

Howard Perry

One of the most significant actions of Congress in 1982 was passage of the Nuclear Waste Policy Act, establishing a national policy for the storage and disposal of high-level radioactive waste. In brief, the act requires the Department of Energy to establish a high-level nuclear waste repository and begin receiving nuclear waste for disposal by January 31, 1998. It also laid down a step-by-step process by which the president, Congress, affected individual states and Indian tribes, the U.S. Department of Energy (DOE), and other federal agencies must work together in the siting, construction, and operation of a geologic repository.

For almost four decades high-level radioactive wastes have been generated in the United States. These have been stored prior to disposal in both large tanks for reprocessing waste and water basins for spent fuel.

Many isolation concepts have been discussed over the years. The proposal to isolate nuclear waste in mined repositories deep underground was first advanced in 1957 by a committee of the National Academy of Sciences. Their recommendation was that rock salt be studied as having favorable characteristics for underground disposal.

A decade was spent evaluating bedded salt as a host rock. Based on that research, we initiated an accelerated program in 1970 to develop a repository in bedded salt at Lyons, Kansas. However, we were not ready either technically or politically for such a major step at that time. Consequently, this program was dropped, and a broader national program looking at additional rock types around the country was initiated.

The studies and exploration in these media—salt, basalt, tuff, and crystalline rock—have continued over the years. However, while the responsibility for the permanent disposal of this waste has rested with the federal government since the Atomic Energy Act of 1954, until recently major obstacles in the United States have impeded the successful disposal of nuclear waste. These have included fluctuations in national policy, unwillingness of states to host a repository, and uncertainty in annual funding for nuclear waste activities.

Recognizing these problems and the need to remove the waste management issue as an impediment to the future use of nuclear power, in December 1982 Congress passed legislation to bring to an end years of indecision on how to solve the problem.

The Nuclear Waste Policy Act of 1982, signed into law by President Reagan on January 7, 1983, provided a mandate and, more important, a set of rules for proceeding with the identification and selection of sites for a repository as well as interim storage facilities in the event they are needed.

The act also established a mechanism to ensure adequate funding for the program through payments by the users of nuclear power. As of April 7, 1983, DOE began charging all U.S. utilities with nuclear power reactors a fee of one milli-cent per kilowatt-hour of electricity generated by a civilian nuclear power reactor for disposal services. Based on this charge, revenue flows will approximate $300 million to $400 million a year. In addition, for existing spent fuel in inventory at reactor sites as of April 7, 1983, there is anticipated revenue amounting to approximately $2 billion. We believe the revenues from this fee will be adequate to cover all projected waste disposal costs.

DOE has the responsibility to provide for the permanent disposal of high-level radioactive waste such as spent nuclear fuel or reprocessed spent nuclear fuel. The act strengthened this responsibility and confirmed the nation's commitment to nuclear waste disposal and to the role of states and the public in the process leading to permanent disposal.

In 1982, while Congress was involved in the deliberations leading to passage of the act, the U.S. nuclear waste isolation technical program was proceeding. Before describing our current efforts I wish to highlight some earlier development activities.

Since 1980 the Climax Spent Fuel Test Program in Nevada has been testing the storage of spent fuel assemblies in a mined granite formation at the Nevada Test Site. This test is now concluded. It included the receipt, encapsulation, storage, and transfer of spent fuel and emplacement of eleven canisters of spent fuel with six electrical simulator canisters
in storage tunnels 420 meters (1,380 feet) below the surface. The heaters produce the temperature expected during the first five years of operation of a waste disposal site. Data from this program are being provided to the Nuclear Waste Test Objectives Project, which include acquisition of rock-stress and temperature distribution data; comparison of the effect of radioactive waste and electric generators; and the magnitude of displacement and stress effects from mining and from effects induced by thermal and radiation activity.

At the near-surface test facility in the Hanford Site in Washington, full-scale heating tests and a rock test are being performed. These are designed to study the response of a basalt rock mass to thermomechanical loading and to measure rock-mass properties. The heater tests are designed to establish a data base for basalt repository temperatures, stresses, and displacements in jointed basalt to verify mathematical models used to predict rock-mass response. The rock test is designed to determine the response of a block of jointed basalt as a function of mechanical and thermal loading expected in a repository environment.

Although not a part of the commercial nuclear waste program, our Savannah River plant has been selected as the first site to solidify DOE-generated high-level waste into a borosilicate glass form suitable for permanent disposal. The process, involving a liquid-fed ceramic melter, has been demonstrated on an engineering scale with simulated wastes and a small pilot scale with actual wastes in hot cells. A facility for this solidification, the Defense Waste Processing Facility, is more than one-third design complete, and construction began in late 1982.

With this as a frame of reference, I would like to focus on major objectives and requirements of the Nuclear Waste Policy Act and on the status of implementation of the act.

**Major Objectives of the Nuclear Waste Policy Act of 1987**

The major objectives of the act are to provide for the development of repositories for the disposal of high-level radioactive waste and spent nuclear fuel; to establish a program of research, development, and demonstration regarding the disposal of such waste and spent fuel, as well as regarding other related purposes;

To achieve these objectives, DOE will pursue four program goals. (1) Site, design, construct, and operate one or more engineered, monitored, retrievable storage facilities by January 31, 1996. (2) Develop and site an engineered, monitored, retrievable storage facility on a schedule that will permit its timely construction should the Congress so determine. (3) Assist utilities in providing adequate, safe, post-reactor storage of spent fuel until federal acceptance and standby ready to deploy limited federal government storage to utilities on an interim basis, if they pre-determined qualified by the Nuclear Regulatory Commission. (4) Manage the technical program and the funds collected for disposal and storage services in an effective and efficient manner.

**Contractual Agreement for Disposal Services**

DOE developed a standard contract for use as the formal agreement between DOE and utilities to dispose of spent fuel or high-level waste beginning in 1998. As set forth in the act, owners and generators of spent fuel or high-level waste had until 30 June, 1983, to execute the contract with DOE. That target, specified in the act, has been met. Seventy contracts have been signed with 56 different organizations, including 46 lead nuclear utilities covering 80 licensed nuclear plants, eight owners of industrial test reactors, and 16 nuclear fuel vendors. The contract sets forth the terms and conditions as well as financial procedures and a fee structure. Furthermore, the contract obligates DOE to begin receiving by 1986 nuclear waste for disposal. Pursuant to this contract, nuclear power plant owners have begun to pay DOE one mill per kilowatt-hour of electric power generated by nuclear power. This is roughly equivalent to $5.25 million per year per 1,000 Mw of plant. Within three years, we expect revenues from this fee to total more than $5.5 billion. In addition, utilities owe us about $2.66 billion for spent fuel generated prior to 1983. All told, we will have received perhaps $10 billion before we begin accepting waste for disposal.

**Site Selection Guidelines**

As a basis for the site selection process, the act required DOE to issue guidelines. These will be used for the recommendation of sites for repositories in geologic formations. The guidelines are based on criteria that DOE has used over the past several years, on regulations of the NRC, and on requirements of the Environmental Protection Agency. They were developed following extensive public hearings and consultation with affected and interested states and federal agencies. The review process was elaborate. DOE held public hearings around the country; met with states; coordinated with several federal agencies; and reviewed more than 2,000 written and oral comments.

While the act called for issuance of the guidelines within 180 days of enactment, we postponed issuance approxi- mately six months so that we could fully evaluate and address the concerns expressed. On November 22, 1983, DOE transmitted the guidelines to the NRC for review and concurrence. When that is received, DOE will issue the guidelines. These estab-
lish the performance requirements for a geologic repository system, define the technical and environmental qualifications that candidate sites must meet, and specify how DOE will carry out its site selection process.

Mission Plan

DOE has prepared a draft Mission Plan describing the program being conducted by DOE to fulfill the requirements of the act. As required by the act, DOE has submitted the draft Mission Plan to the states, the affected Indian tribes, the NRC, and other federal agencies for their comments and has made it available for public inspection. When finalized, the Mission Plan will be submitted to Congress. DOE is required to submit the Mission Plan to Congress not later than seventeen months after enactment of the act. The Mission Plan will present the Civilian Radioactive Waste Management Program's objectives, strategies, as well as key features of the repository program as required specifically by the act.

The First Repository

DOE has identified nine potentially acceptable repository sites in six states and has notified the governors and legislatures of these states. The six are: Louisiana, Texas, Utah, Mississippi, Nevada, and Washington. DOE has held public hearings in those states in the vicinity of the potentially acceptable site to solicit comments on its intent to nominate five or more sites and to receive recommendations on issues to be addressed in an environmental assessment and in any site characterization plan to be used if the site is approved by the president for site characterization. The six sites are in different rock formations; bedded salt formations in Utah and Texas; salt domes in Mississippi and Louisiana; basalt, which is solidified lava, at a federally owned site in Washington; and tuff, a compacted volcanic ash, found at the federally owned Nevada Test Site. The act requires DOE to recommend to the president at least three sites for detailed characterization by January 1985. Detailed site characterization will be based upon a Site Characterization Plan approved by NRC and includes construction of exploratory shafts and extensive testing and data collection. This exploration and testing at depth and on the surface will confirm rock conditions and characteristics.

Following site characterization, DOE will recommend to the president one of these sites for construction of the first repository. Subsequently, the Nuclear Waste Policy Act calls for the president to recommend to Congress the site for the first repository. At this point, the governor of the state in which the proposed site is located may veto the selection, in which case the veto stands unless overridden by both houses of Congress.

Once a site is approved, DOE will submit a construction application to the NRC. The commission has three to four years to approve the application; when DOE receives the construction license, construction will begin. The mandated target to begin accepting waste is 1998.

The Second Repository

The act also provides for the siting and licensing of a second repository. The schedule is for DOE to recommend to the president by July 1989 three sites for detailed site characterization.

As part of its efforts toward siting of a second repository, DOE is conducting studies of existing data on crystalline rock formations in seventeen states to determine potentially acceptable sites. These states are in the north central, northeastern, and southeastern United States. DOE has conducted no field studies in these states and will not do so until completion of literature surveys around the end of 1984. Potentially acceptable sites for the second repository are planned to be identified in early 1985.

Monitored Retrievable Storage

DOE believes the capability to deploy a monitored retrievable storage (MRS) facility would be a prudent addition to the overall nuclear waste strategy. Such a facility could serve as backup to the repository in the event of major delay in repository operation. DOE submitted a report to Congress in June 1983 indicating there are no research and development activities necessary to develop the MRS proposal. By mid-1985, DOE will submit a proposal, supporting plans, and environmental assessments and ask for authorization to develop one or more MRS facilities on a parallel schedule to the repository.

Interim Storage

The act clearly states that utilities have the primary responsibility for the interim storage of spent fuel. For those unable to provide adequate at-reactor storage capacity, DOE is authorized to provide interim storage for up to 3,900 metric tons of uranium of cumulative capacity to about 600 metric tons of capacity were
needed.

As required by the act, DOE will conduct cooperative programs to license and demonstrate dry storage technologies and to conduct a fuel consolidation demonstration. Three utilities have been selected to participate in these cooperative ventures. Agreements are being negotiated with the Virginia Electric and Power Company (VEPCO) in Richmond, Virginia, and the Carolina Power and Light Company (CPAL) in Raleigh, North Carolina, to participate in a demonstration of dry storage of spent fuel in specially designed metal casks and concrete storage modules. A third agreement is being negotiated with the Northeast Utilities Service Company (NUSCO) in Hartford, Connecticut, for participation in a demonstration of spent fuel rod consolidation techniques at a wet storage basin.

The sites selected for the dry storage program are located at VEPCO's Surry Power Station in Surry, Virginia, and at CPAL's H. B. Robinson Power Plant in Hartsville, South Carolina. The site selected for the rod consolidation demonstration is located at NUSCO's Millstone-2 Plant in Waterford, Connecticut.

These cooperative programs are aimed at establishing one or more spent fuel storage technologies which may be licensed by the NRC. Many utilities have already made maximum use of the available storage options. Dry storage and rod consolidation are alternative methods which could provide the needed additional on-site storage capacity in a cost-effective way.

International Cooperation

Safe, permanent disposal of nuclear waste is a global concern. International cooperation is necessary so that all countries requiring disposal may share the results of the development and demonstration of the technology in planning and executing their programs.

Based upon the Nuclear Waste Policy Act, on March 30, 1983, DOE and the NRC published a Joint Notice in the Federal Register announcing an offer by the United States to cooperate with and to provide technical assistance to non-nuclear weapons nations in the field of spent fuel storage and disposal. Responses have been received from Egypt, Brazil, the Netherlands, and Korea; other informal inquiries have been received. In addition, DOE is prepared to engage in information exchange and other forms of cooperation in connection with the disposal of high-level waste. For example, as an alternative to geologic disposal, we are currently studying subseabed disposal. DOE and other federal agencies are participating in international studies to determine the feasibility of subseabed disposal.

We anticipate that there will be continued strong interest among nations in collaborating in the field of nuclear waste management.

Summary

In summary, when nuclear waste is received for permanent disposal in 1998, it will have been preceded by a long and involved research and development program, extensive interactions among agencies of the federal government, and unprecedented in-depth involvement of states, Indian tribes, and the public. With the efforts currently under way and with the detailed program and institutional framework provided by the Nuclear Waste Policy Act, the complex problem of nuclear waste disposal can and will be solved, and in a collaborative manner.
The debate over acid rain goes beyond the survival of sport fish in some of our lakes. First, there is a concern about whether the effects we are now seeing may represent merely the tip of the iceberg. With additional surveys and monitoring of lakes and streams, we might find that the effects are more widespread than we realize. It is also possible that acid deposition is damaging forests and crops. However, we simply do not have enough data today to draw conclusions about these terrestrial effects. More monitoring and research is clearly needed, regardless of whether a control program is enacted.

A second concern running through the debate on acid deposition involves irreversibility or long-term effects. Are we causing damage to our national environment from which any recovery will be impossible? Is recovery possible? Would it require periods measured in decades? What mitigation options exist, if any, and how quickly could they work? Much concern, similarly laced with uncertainty, exists with regard to stressed forested areas at New England or Canadian latitudes, where recovery time is probably several decades.

Finally, there is concern regarding how fast the ecological time clock is running. How rapidly are the changes we see today in the aquatic environment taking place? Competing scientific hypotheses exist. One view maintains that this effect is cumulative; hence there could be substantial additional damage with added acidic deposition. Another suggests that any damage which might occur has occurred, and that the processes active at current acid deposition levels have effects over centuries rather than years or decades. We need to improve our monitoring in this regard and be alert to data indicating early action is required.

These concerns and the great uncertainty that exists about the science have led to a debate about whether additional controls on industrial and utility emissions—over and above those required under the Clean Air Act—should be imposed now, or whether we should wait until further facts are ascertained. Moreover, the issue of acid rain is extremely divisive, pitting different sections of the country, economic forces, and interest groups against one another. It is an especially difficult problem because, in contrast with most pollution control programs, the benefits of the cleanup will not always be enjoyed by those doing the cleaning up. Instead, the bulk of the benefits may be realized by communities several hundred miles away and by persons who have special affinities for the natural environment being protected, such as those who use and are concerned about particularly sensitive areas.

The administration is considering a wide range of policies. At one extreme is the option of accelerated research—a lake liming and restocking program, and other preparations for regulation in the future. At the other extreme, a full control program in the range of eight to ten million tons per year has been considered. Between these extremes are options such as a limited control program combined with further research. For example, controls could be required in a limited number of states. The goal would be to reduce acid rain in a sensitive regional area such as the Northeast and at the same time demonstrate the relationship between emission reductions and reductions in acid deposition. This would be less expensive and less disruptive than a full national control program. It would represent a substantial step toward control of the most serious known effects but would provide flexibility for mid-course corrections as we learn more.

Meanwhile, Congress is also considering several control proposals, ranging from more intensive research efforts to large-scale rollbacks of S02 emissions. This paper will focus on a subset of those proposals, bills which call for S02 reductions of almost 50 percent over an area involving

Note: The acid rain debate has moved rapidly since this paper was drafted. Unless otherwise noted, this paper presents information and analysis as of December 1983; no attempt has been made to follow subsequent developments.
The Allocation Formula

Most of the bills to date allocate an SO₂ reduction of eight to ten million tons among states using an "excess emissions" formula. It is based on 1980 average annual sulfur dioxide emissions from individual power plants. Each state would be assigned a certain percentage of its emissions above a specified rate of sulfur dioxide per million Btu. For example, if the goal is to reduce emissions by eight million tons below 1980 levels in thirty-one eastern states, an appropriate base emission rate would be 1.5 pounds of SO₂ per million Btu. Only the sulfur dioxide emissions at each power plant above the 1.5 pound annual average emission rate would be considered in the allocation scheme. Each state's percentage of the total "excess" emissions (those above the 1.5 pound rate) within the region would be multiplied by eight million tons to determine its sulfur dioxide reduction requirement. The requirement is then subtracted from the state's 1980 SO₂ emissions to determine its future target.

This scheme is relatively efficient in the sense that it approximates a least-cost solution to reducing SO₂ emissions. It is often argued, however, that the formula should be replaced with one that emphasizes reduction of large quantities of natural gas, will be hard-pressed to keep total emissions constant, much less reduce them, and many will have to contend with significant emission increases when they switch to coal as natural gas prices rise.

Moreover, most Sunbelt states are experiencing significant economic growth and will need to build many new plants in the future. The cost of producing electricity from new baseload coal and gas plants (gas is prohibitive) is increasing. These states will find it difficult to obtain emission reductions before the effect of their new units since their existing units are already clean. Many of these plants include exemptions or adjustments for some, but not all, of these states.

One assumption is that governors will allocate reductions among their states' utilities in an efficient manner (either directly or by facilitating intrastate trading of the rights). To the extent that the allocations to utilities are inefficient and trading mechanisms do not develop, the costs of controls will increase.

With usual assumptions about cost-minimizing behavior, a least-cost allocation would be induced if firms were required to internalize the cost of sulfur emissions through imposition of an SO₂ tax. An examination of that option found that, at the level of eight million tons, an SO₂ tax would produce a state-by-state emission pattern strikingly similar to the one associated with an excess emissions allocation (see Table 1). This finding provides additional evidence that the excess emissions formula is a relatively efficient mechanism for allocating a regional SO₂ reduction. The concept and operation...
Table 1. Regional Utility SO₂ Emissions, 1995, 10³ Tons

<table>
<thead>
<tr>
<th>Thirty-one eastern states</th>
<th>Excess emissions allocation</th>
<th>Modified SO₂ tax</th>
</tr>
</thead>
<tbody>
<tr>
<td>ME, NH, VT</td>
<td>59</td>
<td>52</td>
</tr>
<tr>
<td>MA, CT, RI</td>
<td>321</td>
<td>254</td>
</tr>
<tr>
<td>NY</td>
<td>523</td>
<td>366</td>
</tr>
<tr>
<td>PA</td>
<td>1,273</td>
<td>720</td>
</tr>
<tr>
<td>NJ</td>
<td>175</td>
<td>77</td>
</tr>
<tr>
<td>MD</td>
<td>337</td>
<td>150</td>
</tr>
<tr>
<td>VA</td>
<td>233</td>
<td>159</td>
</tr>
<tr>
<td>WV</td>
<td>1,027</td>
<td>491</td>
</tr>
<tr>
<td>NC, SC</td>
<td>730</td>
<td>550</td>
</tr>
<tr>
<td>GA</td>
<td>818</td>
<td>344</td>
</tr>
<tr>
<td>FL</td>
<td>944</td>
<td>489</td>
</tr>
<tr>
<td>OH</td>
<td>2,439</td>
<td>857</td>
</tr>
<tr>
<td>MI</td>
<td>654</td>
<td>367</td>
</tr>
<tr>
<td>IN</td>
<td>1,785</td>
<td>593</td>
</tr>
<tr>
<td>IL</td>
<td>950</td>
<td>479</td>
</tr>
<tr>
<td>WI</td>
<td>675</td>
<td>201</td>
</tr>
<tr>
<td>KY</td>
<td>870</td>
<td>428</td>
</tr>
<tr>
<td>TN</td>
<td>981</td>
<td>503</td>
</tr>
<tr>
<td>AL</td>
<td>425</td>
<td>214b</td>
</tr>
<tr>
<td>MS</td>
<td>276</td>
<td>120b</td>
</tr>
<tr>
<td>MN</td>
<td>389</td>
<td>125</td>
</tr>
<tr>
<td>IA</td>
<td>246</td>
<td>125</td>
</tr>
<tr>
<td>MO</td>
<td>1,272</td>
<td>404</td>
</tr>
<tr>
<td>AR</td>
<td>113</td>
<td>121b</td>
</tr>
<tr>
<td>LA</td>
<td>152</td>
<td>152</td>
</tr>
<tr>
<td>Total</td>
<td>17,465</td>
<td>8,389</td>
</tr>
</tbody>
</table>

Source: Adapted from Analysis of a Senate Emission Reduction Bill (S.3041), ICF, Inc., February 1983.

The tax was set at $360 per ton of SO₂ produced. The revenues collected were then used to provide a $320/ton subsidy to induce additional reductions.

These states choose to use a default option; all major sources in the state must limit their SO₂ emissions to less than 1.2 lbs/mmBtu of heat input.

The proposed acid rain tax will be discussed in greater detail in the revenue section of this paper.

### Allocating Costs through the Utility Ratemaking Process

Unless Congress provides for an alternative financing mechanism, the revenues to pay for acid rain controls will be raised through the utility ratemaking process. S.3041, the Stafford bill, relies on this approach. Congress or the EPA would give each state an emission target. The state would then allocate the required reductions among its utilities. Each utility would decide on an appropriate set of investments or expenditures to achieve the reduction and then ask the state public utility commission (PUC) to approve rate increases to offset the additional costs.

In most instances utilities would have to pay for controls and recover the costs later. The delay before a utility is reimbursed for a pollution control expenditure varies considerably by state. In the case of a capital expenditure, the length of the delay largely depends on whether the PUC allows utilities to charge ratepayers for the financing costs associated with construction work in progress (CWIP). Although CWIP is not generally allowed for new plants, it is frequently permitted for pollution control equipment (such as a scrubber retrofit, or upgrading an electro-static precipitator to handle low-sulfur coal). Unless CWIP is allowed, electricity consumers would begin paying for controls shortly after they are in place. The operating costs would be recovered annually, and the capital costs would typically be amortized over fifteen years.

If the utility were not eventually fully reimbursed for its acid rain control investments, then part of the cost burden would be shifted to the owners of the utility. This could occur in the short run, but ultimately the owners would have to receive competitive rates of return on capital or the firm would be unable to continue offering adequate service.

### Advantages

Since a national program for controlling acid rain siphons off investment and consumption from other sectors of the economy, it should be carried out as economically as possible. The ratemaking process can be one of the more efficient mechanisms available for funding such a program so long as the emission reductions themselves are allocated in a least-cost pattern. Even this requirement could be waived if trading (buying and selling of emission requirements) were allowed and fostered over a sufficiently broad region. The costs would be imposed on those utilities required to clean up their plants, and so long as utilities had the incentive to
to minimize costs, they would be in the best position to make economic choices. This approach is consistent with the polluter-pays principle underlying most existing environmental legislation.

Utilities would receive appropriate signals regarding the true costs of the electricity they produce or buy from different sources and adjust their generating patterns accordingly. Within each plant, each utility would search for the lowest cost SO2 reductions. Given the usual ratemaking process, lags in cost recovery and the reductions in sales associated with higher costs provide ample incentive for cost minimization. (The ability to pass fuel costs forward immediately through fuel clauses may bias utilities against efficient capital-intensive solutions, however, see below.) Ratepayers would also receive a better indication of the total costs—excluding the environmental effects—associated with their consumption of electricity and could adjust consumption of electricity accordingly.

Finally, the incremental administrative costs should be relatively low compared with other approaches. Since the ratemaking process relies on an established system, there would be no need to create a large bureaucracy.

**Disadvantages**

Most of the disadvantages of using the utility ratemaking process relate to the distribution of costs among consumers and the sometimes perverse behavior (in terms of efficiency) to which that distribution gives rise. Economic disruptions and equity concerns also may arise, depending on the size and speed of adjustments required.

Many of the programs currently under consideration would concentrate control costs on a relatively small group of utilities burning high-sulfur coal. If they pass these costs on through the normal ratemaking process, some consumers could face significant rate increases for the first few years after the requirements take effect. An increase of the magnitude implied can have harmful effects on a region's economy, especially since people have been and are being made based on existing electricity rates and patterns. While long-run efficient use of resources requires that these adjustments take place, their speed may add overall costs not compensated for by the efficiency gains achieved.

The effects on personal and regional income distribution may also run counter to broader national policy and may require troublesome and costly compensatory measures. Utilities could protect especially hard-hit low income consumers with some form of assistance, for example, but that would require implementing an even greater burden on higher income consumers and industry. Furthermore, many of the utilities that would pay the most for controls serve regions which are already

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**Acid Rain**

struggling--largely because their major industries were hard-hit by the recent recession and, perhaps, by longer term adjustments to new industrial patterns. If their condition does not improve between now and the mid-1990s, when the costs of SO2 controls would be most severe, double-digit electricity rate hikes could further hasten their decline relative to the rest of the country. Again, such regional readjustments may be necessary and inevitable, but accelerating the speed of adjustment may add unnecessarily to the overall social cost.

The reason these distressed regions have most of the country's highest SO2 emitting plants is that they also have most of the country's highest sulfur coal. To the extent utilities choose to reduce their emissions by switching from local coals to lower sulfur fuels from outside the region, their economies will suffer a second blow. (Our analyses indicate that in most cases such fuel switching is sometimes cheaper for a utility than scrubbing; fuel switching costs $250 to $500 per ton of SO2 removed, compared with $400 to $1500/ton for scrubbing.)

This threat to high-sulfur coal regions could be exacerbated by the fact that the current ratemaking system may tend to direct utilities toward minimizing capital expenditures instead of minimizing costs per kilowatt-hour. Many analysts argue that at present, for a number of reasons, utilities do not receive a rate of return commensurate with the risks they incur on capital expenditures. Therefore, they choose options with relatively high operating and maintenance costs. It is suggested that many utilities have been reluctant to construct coal-burning units, despite the fact that the fuel savings would more than offset the increased capital costs. Similar considerations could cause a utility to fuel-switch rather than install a flue-gas desulfurization system, even if the costs per kWh for scrubbing were cheaper. The effect of the failure to provide utilities with a return appropriate to the cost of capital is exacerbated by the fuel cost adjustment clauses referred to earlier.

Utilities are generally not permitted to recover their costs from ratepayers until they have made an expenditure. Therefore, they must initially enter the capital markets to raise funds to pay for acid rain controls. Some utilities with large current indebtedness, excess generating capacity, and poor prospects for future growth will be hard-pressed to raise the funds required for a control program. Unless some form of state and federal assistance (or up-front payments from ratepayers) is provided, these utilities could face severe capital constraints, even though in the long run they receive an ample rate of return.

Finally the ratemaking system would tend to front-load pollution control costs into the early years of the payback period. Although a utility must spend its own money or borrow
funds to build a project, once it comes on line the utility is permitted to recover its investment rapidly. In the case of acid rain controls these processes could make the first year’s rate increases as much as 50 percent or more. The long-term average costs of the program, adding stress to the consumers and the regions affected. Ratemaking reforms such as allowing CAFR would smooth rates over time but would not eliminate this problem.

**Alternatives to the Ratemaking Process**

Although alternatives to the ratemaking process are generally less efficient, these options may be preferred for two basic reasons. First, on the revenue side, most of the alternatives spread the costs over a broader segment of the population, reducing the chances of saddling any one group of consumers with double-digit rate hikes. A short-run efficiency argument can be made that it is less disruptive (and therefore less socially costly) to require a number of small adjustments rather than a few large ones. Second, the expenditure options provide opportunities to target some of the funds toward goals that many have high social priority, for example, subsidizing hard-hit ratepayers or mitigating adverse effects on high-sulfur coal regions.

There are two types of alternatives, revenue options and expenditure options.

**Revenue Options**

Revenue options entail raising part of the funds for controls based on fuel use, electricity production, the nation’s tax base, or a combination of these sources. Supplemental revenues could still be raised through the normal ratemaking process.

**Generation Tax**. The concept of a generation tax on all nonnuclear electricity production continues a recent trend in environmental legislation; both the Superfund and nuclear waste storage programs rely on forms of generation taxes to subsidize clean-up efforts. The most likely scenario for implementing a generation tax is that EPA or Treasury would administer a trust fund derived from tax or fee revenues. H.R. 3400, the Waxman-Sikorski bill, includes a provision for a one mill/kwh tax. (Expenditure options are discussed in the next section of this paper.) The money would be collected by utilities as a kilowatt-hour surcharge and periodically sent to the fund. All electricity produced by combustion of fossil fuels and by hydropower would be taxed. The logic of this choice can be questioned; there is little more reason to tax gas-fired generation than to tax nuclear generation for sulfur emissions (NOx is a different matter). The tax on hydro production, which entails no emissions, is even more difficult to justify. At the same time, if hydropower is included in the tax base, there is little logic in excluding nuclear power. Alternatively, the tax could be imposed on all electricity generation or only on coal-fired production.

**Revenue Flows**. The taxes proposed thus far fall into the range of one to three mills (a mill equals one-tenth of a cent) per kilowatt-hour. A typical residential customer uses about 500 kwh per month. A one-mill per kwh tax would increase the monthly bill by about $0.60 if all electricity used is covered.

The percentage increase in rates associated with a one-mill fossil-fuel tax would be from 1-3 percent. To the extent that the tax revenues did not fully subsidize the costs of the acid rain controls in a particular state, electricity users would bear additional rate increases beyond those produced by the tax.

A generation tax can produce massive amounts of revenue. A useful rule of thumb is that in 1985 a one-mill per fossil-fuel kwh tax would raise roughly $1.2 billion per year in the 31-state acid rain control region. If the tax is imposed on a 48-state basis, the 1985 revenues would increase to $1.75 billion. The rate could be set in either real or nominal terms.

**Implications**. A generation tax is an effective means for spreading the costs of control over a larger base. Since the base is so broad, the effect on individual regions or states would be relatively small. Therefore, it should not significantly affect competition between electricity and other energy sources or otherwise be disruptive. For example, it is unlikely that many residential or industrial users would switch from electricity to oil or gas heaters because of a generation tax. The tax is relatively easy to collect, roughly equivalent to a sales tax on electricity. Since the tax is based on output rather than input, it should not change the relative prices of fossil fuels.

At the margin, with a fossil-fuel tax, some utilities might choose to use their nuclear and hydro plants more intensively to avoid the surcharge, but this effect is not likely to be significant. Nuclear plants are already baseload capacis and hydro capacity is limited in the amount of energy it can produce as a function of available water. Moreover, a one-mill differential is relatively small compared to the other factors involved in dispatching decisions.

Perhaps the most serious criticism of a generation tax concerns equity: It does not give credit for current and historical clean-up efforts. Those consumers who have already paid for scrubbers or switched to or continued to use costly low-sulfur fuels would pay just as much as ratepayers of utilities with relatively uncontrolled units. The criticism is less telling to the extent that revenues are used to subsidize, rather than fully fund, the costs of controls.
Another response to this criticism might be to meld the generation tax within an emissions fee approach to create a system of graduated fees based on emission rates. For example, power plants with emission rates lower than 1.5 lbs./MWh could pay a smaller fee per kWh than those plants with higher emission rates. This approach would also provide an incentive for utilities to operate their cleaner units somewhat more intensively than under current practices. It bears the disadvantage of creating an artificial discontinuity at the emission rate(s) selected which would lead to distortions in decisions. Moreover, the gradations selected would be difficult to justify on either environmental or economic grounds.

Btu Tax. A Btu tax is similar to a generation tax, except that it taps a broader base. For example, it could be levied on all fossil-fuel consumption by utility boilers, industrial boilers, and process heat applications. For simplicity in administration it could be limited to those units above a given level of consumption. Under this approach, utilities and their ratepayers would only have to pay about two-thirds as much as they would under a generation tax. The tax would either be a surcharge on fuel purchases or calculated from fuel consumption. (It would be far easier to administer a surcharge on fuel purchases than to estimate consumption.) Again, EPA or Treasury would collect the tax.

Revenue Flows. A tax of 6.13 cents/10^8 Btu would be roughly equivalent to a one-cent per kWh generation tax. The key difference is, as noted earlier, that about 35 percent of the revenues would be provided by the industrial sector. A 5.06/10^8 Btu tax is relatively small compared to the projected 1985 (delivered) prices of fossil fuels.11

<table>
<thead>
<tr>
<th>Fuel</th>
<th>$/10^8 Btu</th>
<th>% increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1.75-3.00</td>
<td>2-3</td>
</tr>
<tr>
<td>Natural gas</td>
<td>3.50-5.50</td>
<td>1-2</td>
</tr>
<tr>
<td>Residual oil</td>
<td>3.50-5.50</td>
<td>1-2</td>
</tr>
<tr>
<td>Distillate</td>
<td>6.00-6.50</td>
<td>1</td>
</tr>
</tbody>
</table>

Implications. A Btu tax could raise almost $2 billion annually without increasing fuel prices by more than 3 percent. To the extent an incentive is created, it would be to favor more efficient energy use. The fewer Btu's consumed, the smaller the tax bite.

A Btu tax could be criticized for not providing credit for current pollution control efforts. On this score it rates even lower than a generation tax. On this score it does not provide credit, but also further penalizes sources that have incurred energy penalties by installing such equipment as wet scrubbers or scrubbers to control emissions.

Emissions Fee. Economists have frequently argued that an emissions fee is an efficient mechanism for dealing with pollution problems. Whereas a generation or Btu tax imposes equal costs on all electricity or fossil-fuel users, an SO2 tax would impose a heavier burden on those sources which are relatively large SO2 emitters than on sources which have done a better job of controlling or limiting their emissions. Therefore, this approach results in electricity prices better reflecting the full cost—including the environmental effects—of production.

An emissions fee linked to acid deposition controls could take the form of a tax placed on each ton of SO2 produced by utilities and industry. The emissions from each source would either be monitored or, with far greater administrative simplicity and little loss in precision, calculated using data on fuel inputs and the appropriate emission factors for that source. The funds would be collected by EPA or the Treasury.

An SO2 tax differs from Btu or generation taxes in that it is not intended simply to raise revenues that would then be disbursed for some purpose related to acid deposition control. Instead, it would both directly address the SO2 loadings problem by changing sources' behavior and raise revenue for further control efforts.

Ideally, the tax would be set somewhat lower than the marginal cost of control for the last ton of emission reduction required. Sources that could reduce their emissions relatively cheaply would do so to avoid paying the tax. Other sources facing relatively large control costs would generally choose to pay the tax. (In the case of utilities, public pressure could cause them to pay the additional amount required to reduce their own emissions, which have some local benefits, rather than send the money to Washington.)

The revenues collected by an emissions fee could be used to fund the remaining required reductions. EPA, acting on its own or through each state, would use the revenue to purchase the additional reductions (presumably from the most cost-effective bidders).

An SO2 tax does not necessarily have to be the mechanism for both raising revenues and allocating the desired level of emissions reductions. It could be used, on a smaller scale, to raise the revenues required for subsidizing ratepayers or protecting miners [see below].

Revenue Flows. A $120/ton SO2 tax, imposed on major sources, would raise roughly as much money as a one-cent per kWh generation tax. It would also induce a few sources to reduce their emissions (to avoid paying the tax). A major criticism of an SO2 tax is that it concentrates the burden on those areas that will also be expected to incur the costs
of controls and in that way mirrors the effects of the normal remaking process discussed above. Yet, these areas will receive many of the benefits from the tax when the revenues are disbursed.

Table 2 compares the state-by-state effects of a one-mill generation tax and an SO2 tax designed to raise equivalent revenue.

**Implications.** EPA's Office of Policy Analysis recently requested ICF to assess the economic and environmental effects of meeting the eight-million-ton rollback called for in S.3041 using an SO2 tax. The tax was set at $360/ton. That tax rate was not adequate to induce the full rollback. However, through a model, the revenues collected were then used to provide a $220/ton tax credit for additional sources willing to reduce their emissions. This approach enables the rollback to be accomplished at about the same cost as using the allocation formula in the bill. In addition, the rate increases are somewhat more evenly spread over the 31 states than would occur under the allocation formula. The coal market effects are almost identical: roughly a 100-million-ton shift in production from northern Appalachia and the Midwest to central Appalachia and the West.12

An SO2 tax would present some administrative difficulties. Although environmental authorities can generally estimate a plant's maximum emissions rate, they would have difficulty determining precisely its total emissions without a continuous emission monitor. (Very few utility plants, much less industrial sources, have continuous emission monitors [CEMs].) They would probably have to use a self-reporting process comparable to the income tax system based on fuel used and calculated emissions factors. Thus, it would be necessary to invest in either a massive CEM installation effort or an emission auditing program.

The SO2 tax imposes costs in a pattern similar to, but not as focused, as an excess emissions allocation system coupled with the normal remaking process (such as the Stafford bill). The costs are concentrated on a handful of states, and some individual utility systems would still have to pass through large expenditures to their ratepayers. The equity consequences are of significance. High-sulfur coal regions will assert that it is inequitable to impose such a large share of the control costs on them. Users of gas and oil could respond that no special efforts were made to cushion their OPEC-induced price increases in the 1970s. Those effects on rates were far more severe than the potential costs of acid rain controls. For example, many electricity consumers in the Northeast experienced oil-driven rate increases exceeding 50 percent.

An SO2 tax used to allocate the reduction would prevent sources from having to pay exorbitant costs per ton of SO2 removed, since they would choose to pay the fee rather than
### Table 2. State Shares under Alternative Financing Mechanisms -- continued.

<table>
<thead>
<tr>
<th>State</th>
<th>Fossil-fuel generation tax ( ^b ) 1 mill/kwh</th>
<th>SO(_2) emission tax ( ^b ) $0.05/lb SO(_2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(millions of 1982 dollars)</td>
<td>(millions of 1982 dollars)</td>
<td></td>
</tr>
<tr>
<td>Alabama</td>
<td>33</td>
<td>66.4</td>
</tr>
<tr>
<td>Mississippi</td>
<td>19</td>
<td>17.6</td>
</tr>
<tr>
<td>Minnesota</td>
<td>13</td>
<td>20.1</td>
</tr>
<tr>
<td>Iowa</td>
<td>27</td>
<td>24.9</td>
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<tr>
<td>Missouri</td>
<td>58</td>
<td>2.1</td>
</tr>
<tr>
<td>Arkansas</td>
<td>16</td>
<td>17.4</td>
</tr>
<tr>
<td>Louisiana</td>
<td>32</td>
<td>8.4</td>
</tr>
<tr>
<td>North Dakota</td>
<td>24</td>
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<td>Oregon</td>
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\( ^a \) Based on projected 1985 electricity demand.

\( ^b \) Assumes 5 percent drop in SO\(_2\) boiler emissions because of the tax.
make the investment. Alternatively, the goal of minimizing wasteful investment in costly reductions could also be achieved by allowing emissions trading.

Sulfur-in-Fuel Tax. A sulfur-in-fuel tax would be comparable to an SO2 tax with one important distinction: it would be based on sulfur input instead of SO2 output. The tax would be imposed on the sulfur content of fossil-fuel purchases. It would probably need to be based on potential SO2 emissions/m\text{Btu} in order to standardize between liquid and solid fuels.

As would be the case in other emission-based charges, some sources would shift to lower sulfur fuels to avoid the tax, while others would pay it. Again, the revenues could then be used to pay for additional emission controls. Unless some type of credit is provided, however, this approach would be doubly unfair to sources with scrubbers. They would still have to pay the tax, despite their large investment in pollution control, and the scrubbers thereby reduce SO2 emissions.

With the credit, itself hard to administer, the effects of the sulfur-in-fuel tax would be virtually identical to those of an SO2 tax. Without the credit, it is unlikely that any scrubber retrofits would occur. The credit could be designed to leave sources indifferent between scrubbing and fuel switching, or could be generous enough to encourage scrubbing.

It would be easier to implement a sulfur-in-fuel tax than a tax on SO2 output. Sulfur content of fuels can be determined far more readily than SO2 output from emission sources. Administrative ease would be offset, however, by the lack of incentives to reduce postcombustion emissions.

Transferable Emission Permits. The issuance of transferable emission permits would be an efficient alternative to an emissions tax. Under this proposal, permits allowing discharge of a specified quantity of SO2 would be sold or given to utilities. Permits would be freely transferable. The geographic area for which permits were effective could be restricted as a means of controlling emissions.

High-emission electricity suppliers or suppliers for whom the cost of emissions reduction is relatively high would retain permits initially allocated and purchase additional permits as needed from low-emission suppliers or suppliers for whom the cost of emissions reduction is relatively low. Assuming unrestricted market transfers, the resulting allocation of permits should minimize the cost of reducing emissions to the sum allowed by the permits issued. Unlike an emission tax, there would be no uncertainty as to aggregate emission levels, since total emissions could not exceed the sum of the permits. The administrative obstacles to implementing the program would be similar to those associated with an SO2 tax. Most notably, a source-by-source monitoring or auditing program would have to be established.

Direct Federal Budget Outlays. All or part of the costs of acid rain controls could be paid for directly out of the federal budget. This approach would spread the costs over a large base without requiring additional bureaucratic resources to raise the revenues. It would neither provide credit for current clean-up efforts nor change relative energy prices. A major result would be to increase taxes or the federal deficit. This approach would explicitly state that acid deposition is a national issue akin to providing defense or recreational amenities such as the national park system.

Table 3 summarizes the implications of alternative revenue sources.

Expenditure Alternatives

If one or more of the options described in the previous section should be enacted, funds could be made available to alleviate the economic hardships caused by efforts to control the adverse effects of acid rain. These are referred to as expenditure alternatives.

Subsidize Ratepayers. One possibility would be to tax credits to subsidize ratepayers (mostly in the Midwest) who would otherwise have to pay more than some maximum acceptable amount for controls.

The most likely procedure would be for each utility to calculate its costs for acid rain controls per kw produced. Ratepayers would then receive an annual statement indicating how much of their payments for the past year were spent for acid rain controls. A new tax credit—for all or part of these expenditures—would then be added to the personal income tax form (1040). These credits. This approach would largely preserve utilities' incentives to meet their emission reduction targets at least cost, particularly if ratepayers do not receive full credit for their expenditures. The control program itself would still be implemented through the normal ratemaking process. However, relying on that process has all the implications noted earlier, including the fact that utilities would be required to raise the funds for controls before being reimbursed. Similarly, ratepayers would need to spend the money for controls "up front" and be reimbursed later.

A program to provide tax credits for acid rain controls would be very difficult to administer. Determining a utility's control costs is more art than science. The calculations depend on assumptions such as what type of coal the source would have used in the absence of an acid rain control effort and what it would have cost; what portion of a new plant should be allocated to displacing dirty sources and what portion is intended to meet new load growth. Each utility's cost estimate would have to be carefully audited, requiring hundreds—if not thousands—of lawyers, accountants, and engineers.
### Table 3. Implications of Alternative Revenue Sources

<table>
<thead>
<tr>
<th>Administrative problems</th>
<th>Cont. Sharing</th>
<th>Polluter</th>
<th>Revenue Source</th>
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<td>difficult</td>
<td>moderate</td>
<td>Utility retaking process</td>
</tr>
<tr>
<td>difficult</td>
<td></td>
<td>difficult</td>
<td>1. Rebate of tax (or transfer of permits) on sulfur-removal equipment (scrubbers and baghouses)</td>
</tr>
<tr>
<td>not difficult</td>
<td>not difficult</td>
<td>moderate</td>
<td>Generation tax</td>
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<tr>
<td>not difficult</td>
<td></td>
<td>moderate</td>
<td>Federal budget outlays</td>
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</table>

**Acid Rain**

A somewhat less complicated approach would be to determine the tax credit through requiring each utility to take its allocated reduction in SO₂ and multiply it by a national or state average cost per ton of SO₂ removed, and divide that product by the number of kw-h produced. This formula would penalize customers of utilities forced to implement costly reductions and more generously reimburse those ratepayers whose utilities could reduce emissions at relatively low cost.

The program would be even easier to implement if it were limited to offsetting rate effects from scrubber investments. This approach would have two further implications. It would encourage (perhaps inefficient) scrubbing, since ratepayers would not receive tax credits for other investments, and it would still provide assistance for those ratepayers hardest hit by control costs, since they would tend to be customers of utilities which build scrubbers.

**Direct Payments to States.** Some states which use large quantities of high-sulfur coal will be particularly hard-hit by acid rain controls. It may be deemed equitable, particularly if SO₂ controls are imposed on a limited number of states, to compensate them partially. In this case, the subsidies would be directed at states instead of individuals. Payments would be similar to block grant revenue sharing; state officials would be responsible for distributing the money. The funds might be used to subsidize utility control choices (cool cleaning, fuel switching, or scrubbing), compensate dislocated workers, mitigate adverse effects on specially affected communities, or reimburse certain classes of ratepayers. The basic principle is that the federal government should not limit the ability of states to respond to their individual needs.

The most likely scenario is that funds would be paid out over a number of years according to a formula based on the total estimated costs of controls for all states involved in the rollback. States would then receive payments in proportion to the reduction in emissions they must achieve. The alternative—payments based on actual expenditures—would complicate administration and eliminate the incentive for states to seek least-cost emission control strategies.

This approach creates a mechanism for addressing the dislocations produced by acid rain controls, yet preserves the incentives for minimizing the costs of the program. The drawbacks are that some people will be skeptical of states' abilities to balance equity and efficiency considerations in allocating the funds.

**The Effects on High-Sulfur Coal Regions**

Given the nature of the acid rain problem, economies producing and/or using high-sulfur coal may suffer seriously
from acid rain controls. The revenues raised by one or a combination of the alternatives discussed above could be used to offset some of the equity and dislocation consequences of the control strategy. The resulting impact would depend largely on how broadly the concept of "adverse effects" is defined.

The narrowest interpretation is that some currently employed high-sulfur coal miners would lose their jobs as a result of fuel switching. (Total mining employment would not change, but it would be redistributed toward low-sulfur coal regions.) The problem could also be viewed from a regional economic perspective: if mining activity drops below current levels, it will erode the region’s economic base and affect ancillary activities. An expansion of the condition would be to hold all parties harmless by offsetting the job losses to high-sulfur coal producing firms and associated enterprises and workers. Another interpretation would use projected levels of mining (and regional employment) as a baseline. In the latter case, the adverse effects would be defined to include not only job (and other) losses relative to current employment levels, but also losses relative to what, for example, 1995 production levels would have been in the absence of controls.

If the objective is solely to protect those high-sulfur coal miners who are currently employed and then lose their jobs as a result of an acid rain control program, adjustment assistance is called for. However, if the goal is broader than aiding displaced miners, that is, enabling high-sulfur coal producing regions to maintain current or projected levels of economic activity, miner adjustment assistance alone would not be adequate.

Another option would be to avoid dislocation altogether by encouraging continued use of higher-sulfur coal. For example, utilities might be provided subsidies for scrubbing so that it becomes an economical alternative to fuel switching. Understanding the implications of each of these options must start with a view of the employment effects of an acid deposition control program.

Potential Employment Effects

ICF estimates that, assuming intrastate trading, utilities will install eight additional gigawatts of scrubbing capacity to meet the eight-million-ton rollback called for in the reduction emissions by less than the projected levels without acid rain controls. Compared to 1980 employment levels the job losses would be about 20,000.14 These effects would probably occur over two years. A rough estimate of total effects would be 2.5 additional jobs lost for each coal miner’s job lost. These projections are gross; they do not include other job losses in other regions by low-sulfur coal mining and related enterprises or by the normal processes of adjustment within an economy.

These estimates represent reductions in prospective, not current, employment levels, that is, the ability of the region to provide employment for new miners. The number of currently employed miners who would lose their jobs is considerably smaller, by the time acid rain controls would be implemented, many presently employed miners would have left their jobs as a result of normal turnover and retirements, and they simply would not be replaced. In addition, some miners who lose jobs in high-sulfur coal regions will be able to find new ones in low-sulfur regions. However, past experience indicates that only a small proportion of unemployed high-sulfur coal miners will be able to take advantage of these openings elsewhere; many of the jobs will go to local residents who are currently unemployed.

Although jobs are lost in high-sulfur coal regions, new ones are created in low-sulfur coal regions (predominantly the West and central Appalachia). Wet coal miner employment, even after taking productivity differences into account, should be about the same after the switches occur. However, it can be argued that the costs of disruptions associated with losing a job and reducing the size of a community are far more significant than the benefits of creating a new position elsewhere. In part this is because of the social costs of disruption. From an economic point of view, some of the capital investment in production facilities, infrastructure (streets, schools, sewer systems), and property, residences in declining regions becomes useless, and new investment must be generated in burgeoning communities. Such expansion drains capital with alternative uses and lowers overall national wealth compared to maintaining previous patterns of production.

Miner Assistance Programs

One way to assist miners would be to allocate money to each affected state and allow it to choose how to use it. The harm brought to its mining communities. The adjustment assistance could be in the form of payments to individuals or communities heavily dependent on the mining industry. The first-year costs could range from $200 million to well over $1 billion, depending on the extent to which displaced miners are compensated and the extent of aid granted to adversely affected communities. Costs would decline as current miners reach retirement age and community aid is phased out.
from acid rain controls. The revenues raised by one or a combination of the alternatives discussed above could be used to offset some of the equity and dislocation consequences of the control strategy chosen. The approach selected would depend largely on how broadly the concept of "adverse effects" is defined.

The narrowest interpretation is that some currently employed high-sulfur coal miners would lose their jobs as a result of fuel switching. [Tota mining employment would not change, but it would be redistributed toward low-sulfur coal regions.] The problem could also be viewed from a regional economic perspective. If mining activity drops below current levels, it will erode the region's economic base and affect ancillary activities. An expansion of the condition would be to hold all parties harmless by offsetting the losses to high-sulfur coal producing firms and associated enterprises and workers. Finally, the most expensive interpretation would use projected levels of mining (and regional employment) as a baseline. In the latter case, the adverse effects would be defined to include not only job (and other) losses relative to current employment levels, but also losses relative to what, for example, 1995 production levels would have been in the absence of controls to fuel switching. If the objective is solely to protect those high-sulfur coal miners who are currently employed and then lose their jobs as a result of an acid rain control program, adjustment assistance is called for. However, if the goal is broader than aiding displaced miners, that is, enabling high-sulfur coal producing regions to maintain current or projected levels of economic activity--miner adjustment assistance alone would not be adequate.

Another option would be to avoid dislocation altogether by encouraging continued use of high-sulfur coal. For example, utilities might be provided subsidies for scrubbing so that it becomes an economical alternative to fuelswitching. Understanding the implications of each of these options must start with a view of the employment effects of an acid deposition control program.

Potential Employment Effects

ICF estimates that, assuming interstate trading, utilities will install eight additional gigawatts of scrubbing capacity to meet the eight-million-ton rollback called for in S. 3041,13 however, since that amount of scrubbing would reduce emissions by less than two million tons, most of the reductions would be achieved by fuel switching. The reductions in miner employment in northern Appalachia and midwestern high-sulfur-coal regions--compared to the projected 1995 levels without acid rain controls--could exceed 40,000 jobs. Compared to 1980 employment levels the job losses would be about 20,000.14 These effects would probably occur over two years. A rough estimate of total effects would be 2.5 additional jobs lost for each coal miner's job lost. These projections are gross; they do not include other jobs created in other regions by low-sulfur coal mining and related enterprises or by the normal processes of adjustment within an economy.

These estimates represent reductions in prospective, not current, employment levels, that is, the ability of the region to provide employment for new miners. The number of currently employed miners who would lose their jobs is considerably smaller; by the time acid rain controls would be implemented, many presently employed miners would have left their jobs as a result of normal turnover and retirements, and they simply would not be replaced. In addition, some miners who lose jobs in high-sulfur coal regions will be able to find new ones in low-sulfur regions. However, past experience indicates that only a small proportion of unemployed high-sulfur coal miners will be able to take advantage of these openings elsewhere; many of the jobs will go to local residents who are currently unemployed.

Although jobs are lost in high-sulfur coal regions, new ones are created in low-sulfur coal regions (predominantly the West and central Appalachia). Net coal miner employment, even after taking productivity differences into account, should be about the same after the switches occur. However, it can be argued that the costs of disruptions associated with losing a job and reducing the size of a community are far more significant than the benefits of creating a new position elsewhere. In part this is because of the human costs of disruption. From an economic point of view, some of the capital investment in production facilities, infrastructure (streets, schools, sewer systems), and private residences in declining regions becomes useless, and new investment must be generated in burgeoning communities. Such expansion drains capital with alternative uses and lowers overall national wealth compared to maintaining previous patterns of production.

Miner Assistance Programs

One way to assist miners would be to allocate money to each affected state and allow it to choose how to cushion the harm brought to its mining communities. The adjustment assistance could be in the form of payments to individuals or communities heavily dependent on the mining industry. The first-year costs could range from $200 million to well over $1 billion, depending on the extent to which displaced miners are compensated and the extent of aid granted to adversely affected communities.15 Costs would decline as current miners reach retirement age and community aid is phased out.
This approach presents three problems. First, compensation, retraining, and relocation assistance is difficult to implement. It would be hard to identify exactly which miners lost their jobs as a result of acid rain controls. Moreover, retraining and relocation programs have only had mixed success in the past. Adding high-sulfur coal mines would be particularly difficult, since they generally live in regions where relatively few new jobs are being created, and the new jobs in low-sulfur regions will occur where, at least at present, substantial employment already exists.

Second, communities in high-sulfur coal regions would still be likely to experience significant "secondary" job losses. Past efforts to rebuild the economic base of regions which have suffered similar blows have only rarely been successful.

Third, such assistance would not help high-sulfur coal companies, which would still experience large losses in the value of their coal reserves.

Protecting High-Sulfur Coal by Scrubbing

If an acid rain control program is implemented, it would not be the first time environmental regulations have threatened the jobs of high-sulfur coal miners. For example, many new power plants were meeting the 1971 New Source Performance Standard for utility boilers (a 1.2 lb. SO2/mmtu limit) by burning low-sulfur coal. In 1977, however, Congress directed EPA to revise the standard so that all coal-fired boilers must achieve a percentage reduction in the SO2 content of their fuel. The effect was to require all new plants to meet the standard by scrubbing. The result has been to drive new plants in the East toward using high-sulfur coal (because it is generally cheaper than low-sulfur coal, and either one would have to be scrubbed). Similarly, an acid rain control program might protect high-sulfur coal markets by requiring or inducing existing power plants to scrub instead of switch fuel.

The costs of fuel switching range from $250 to $500 per ton removed. Scrubbing high-sulfur coal generally costs $400 to $500 per ton removed. The overlap is indicative of the fact that those plants lacking easy access to low-sulfur coal (through existing rail or barge links) or those fortunate enough to be burning low cost high-sulfur coal (for example, a mine-mouth plant) are likely to give scrubbing serious consideration.

As noted before, for an eight-million-ton rollback similar to the one called for in S.3341, utilities would choose to scrub about 6GW of capacity, providing about two million tons of emission reduction. Another 30 GW of capacity could be scrubbed at relatively low additional cost as compared to the least-cost alternative. These plants have adequate space to retrofit a scrubber, but it is estimated that it still would be slightly less expensive to switch to low-sulfur coal.

Scrubbing 30 GW would enable most high-sulfur coal states to continue producing at close to current levels. The additional cost, on an annualized basis, would be about $200 million—adding less than 10 percent to the least-cost price tag for an eight-million-ton rollback. The net costs are relatively small because the increased capital expense of the scrubbers is almost completely offset by the decline in low-sulfur coal prices (resulting from decreased demand). However, these additional costs are real resource costs; they represent diversions of capital from other, more productive, uses. By contrast, direct payments to miners would simply be redistributive in nature. The cost of inducing additional scrubbing beyond the first 30 GW increases rapidly.

It would require 50 GW of scrubbing (beyond the 8 GW in the least-cost scenario) to ensure that in 1990 high-sulfur coal states would be producing at least as much coal as they were in 1980. (This level of scrubbing would also allow for some growth in production.) The annualized cost in 1995 would be roughly $700 million, depending on how the scrubbing inducement was structured. Again, these are real resource costs that lower the potential output of other goods and services.

Approaches for convincing utilities to scrub rather than switch fuel include: subsidies for scrubbing designated power plants, optimal capital subsidies, and federal loans or tax credits.

Subsidies for Designated Plants. The Woman/Sikorsky bill (H.R. 3400) designates fifty of the nation's dirtiest plants (about 60 GW) and requires them to retrofit scrubbers by 1990. Ninety percent of the scrubbers' capital costs would then be reimbursed from a fund created by a generation tax. The tax would be one mill/kwh (1¢/kwh) imposed on all fossil-fuel generated power in 1984 states for about ten years beginning in 1985. The highest 50 emitters might be thought to be fairly cost-effective targets for scrubbing. However, some of the plants designated in H.R. 3400 turn out to be poor candidates for retrofit. For example, a few of the units are old and may not have sufficient remaining lives to justify the new investment. Others have space constraints that make it difficult to install a scrubber. Finally, some are already using or have ready access to low-sulfur coal, so the incremental cost (in terms of $/ton of SO2 removed) of scrubbing is quite high.

Although the H.R. 3400 list poses some problems, conceptually it is feasible to designate plants for which scrubbing would be relatively cost effective. To do so would substitute government judgment based on engineering and cost data for
the decisions of utilities presented with economic incentives such as those described below, with obvious potential for error due to lack of full information.

**Optimal Capital Subsidies.** Another approach would be economic incentives for utilities who choose scrubbing. Capital subsidies are one alternative. States or utilities would not be required to achieve their allocated reductions through scrubbing, but to the extent they chose to do so, the capital costs of scrubbers would be subsidized. If the capital subsidy were 100 percent, calculations based on ICF analyses suggest that states would inadvertently choose to meet 5.304 Pg targets by scrubbing about 80 Gw of capacity. This outcome would protect current and projected coal production in all high-sulfur coal states. The required subsidy ($38 billion) could be raised by a 1.2 mill/kwh (real) generation tax imposed from 1985 to 1995 in the 31-state region. The remaining costs of the rollback (roughly equivalent to the capital cost subsidy) could be paid by ratepayers.

Based on the same analysis, a 15 percent capital subsidy would result in states choosing to scrub considerably less capacity, about 40 Gw. Only one state producing high-sulfur coal—Illinois—would be likely to suffer serious production declines with a 15 percent subsidy. In this scenario, by 1995, Illinois coal production would be less than 50 percent of 1980 levels. However, we project that after 1995 this decline will be reversed, and Illinois would experience rapid growth in coal production.

A capital subsidy would not apply to the annual operating and maintenance costs of the scrubbers, which would be almost as large as the annualized capital costs. Therefore it moderate, but does not eliminate, the relatively large rate increases likely to be experienced in some areas. It would, however, avoid problems of utilities in mobilizing capital. Thus, this approach combines a polluter-pays principle with cost sharing.

**Tax Credits for Scrubbers.** It might also be possible to induce utilities to scrub rather than switch fuel by increasing the tax credits available for scrubbing. In effect, this is similar to the capital subsidies. The major difference is that payments would be made through an existing mechanism—the federal tax system—instead of from a trust fund. This mechanism could be made either with or without the revenue alternative discussed above. If the tax credit approach were used, the generation tax would flow directly to the Treasury to offset these tax expenditures.

Another important difference is that the credit probably could not be claimed until after the scrubber was built. The utility would still have to raise the money in the capital markets. Finally, some utilities would not be able to take advantage of the credit. They already have more credits then they can use as a result of large capital investment programs and relatively small incomes. Thus, tax credits would have differential effects among utilities unless provision was made for the "sale" of excess credits, as in the Economic Recovery Tax Act of 1981.

**Interest-Free Loans for Scrubbers.** A key to some utilities' reluctance to scrub is the risk and uncertainty associated with raising capital to finance the construction costs of flue-gas desulfurization equipment. Interest-free loans would enable utilities to pay for scrubbers without having to obtain funds from the capital markets. From the utility's perspective, the scrubber would become an operating cost (similar to fuel switching) instead of a capital investment.

If the loan repayment were made in equal installments, the front-loading effect on first-year rates would be avoided. A potential problem is that adding the loan liability to a utility's books could limit its ability to raise money for other capital investments.

The effect of the loans on the Treasury would vary widely, depending on how the program is structured. There would have to be a multibillion-dollar front-end expenditure, but the negative effect on the national debt of the initial payments would be partially offset by the repayments in the later years. If the goal were to prevent any drain on the Treasury, the initial capital (and forgone interest) would have to be raised by one of the revenue options discussed earlier.

**Issues Generated by Subsidized Scrubbing.**

The concept of subsidized scrubbing raises a series of difficult design issues, a few of which are discussed below.

How could disbursements be structured to encourage utilities to minimize costs of expenditures for control technologies? If utilities are reimbursed for capital expenditures alone, they are likely to invest in expensive systems that minimize reliability penalties and operation and maintenance (O&M) costs, even though life-cycle costs would be larger and resources would thus be wasted. One alternative would be to establish a fixed payment per kw of scrubber capacity installed. However, determining a standard payment for retrofitting scrubbers would be difficult; the costs could vary greatly, depending on the layout of the plant. For example, a 1981 analysis of the potential for retrofitting scrubbers on large power plants estimated that the costs per kw of capacity scrubbed could vary by as much as 80 percent.

This differential, incidentally, suggests the social gains to be had from establishing economic incentives that lead those utilities who can scrub at lowest cost to do so while others switch.

Another possibility would be to use a matching formula...
so that capital costs would be shared with utilities. The subsidy could also be provided in the form of a subsidized loan instead of a grant. This option would impose financial discipline on utilities, while pushing rate increases for heavily affected areas into later years. Both of these proposals would reduce—but not eliminate—the incentive for "gold plating."

Alternatively, the funds could be allocated to each state based on estimates of their total capital (or capital and O&M) requirement for their share of total loading reductions. Each state would then be responsible for parceling out the money to its utilities. Ideally, state energy offices or RUCs, which are often familiar with utilities' plants, would participate in the allocation decisions.

An approach that largely avoids this bias would be to provide the dollars per annual ton of SO2 removed by scrubbing (the total revenues in the fund divided by the number of annual tons of SO2 to be removed by scrubbing). Although the actual costs per ton of SO2 removed would vary greatly, the pattern of over- and underpayments would be more defendable than those associated with flat payments per kw of capacity. Utilities that build very cost-effective scrubbers might recoup their full costs. A $150/ton removed subsidy for scrubbing would be roughly comparable to a 75 percent capital subsidy. Based on our analyses, if the subsidy were increased to $250/ton it would prevent about as many coal-mining job switches as a 100 percent capital subsidy.

How can utilities be assured that public utility commissions will not simply pass on the benefits of disbursements to ratepayers without mitigating the control cost burden to shareholders? Utilities will undoubtedly be concerned that their commissions may use the disbursements as a rationale for reducing utility shareholders' ratiable returns on other investments. There is probably no constitutional means for the federal government to prevent this outcome, but it can be argued that this problem is unlikely to develop. If the scrubbers' capital costs are fully paid from the fund, there is no need for them ever to appear in the ratebase—or be considered at rate hearings. Moreover, while pass-through may occur in the short run, PUCs are obligated in the long run to provide a rate of return commensurate with the overall cost of capital or face dissipation of that service.

Even if PUCs do divert some of the funds to ratepayers, utilities would still be better off than if they had to raise the revenues for control equipment themselves. The rate increases required for utility-financed controls would probably make PUCs even more determined to limit allowable rates of return. In addition, utilities would be saddled with large amounts of long-term debt.

How could the tax revenues promote the use of innovative control technologies? The Congressional Research Service is examining sliding-scale capital subsidies to promote the use of innovative control technologies. For example, utilities might receive a 75 percent capital subsidy for building a proven flue-gas desulfurization system and a 20 percent subsidy if they instead opt for a lime stone injection multi-stage burner (LIMB) or other advanced technology. Table 4 summarizes the expenditure options discussed above.

Summary and Conclusions

Ideally, if an acid rain control program is enacted, the financing component will be developed in two steps. First, a decision will be made as to how the costs should be allocated among groups and which adverse effects should be mitigated. This process is political. It requires difficult judgments regarding equity among regions, economic interests, and individuals.

The second step involves development of financing mechanisms which reflect those allocation decisions. This paper has provided an overview of the provisions that could be used.

1) If the goal is to adhere to the polluter-pays principle, either an SO2 tax or the normal ratemaking process coupled with an efficient allocation formula should be employed. These options, if efficiently implemented, enable SO2 reductions to be obtained at least cost.

2) Although alternative financing schemes are generally less efficient, these options may be preferred for two reasons. One type, revenue alternatives, spreads the costs over a broader segment of the population, reducing the chances of imposing large rate hikes on any one group of consumers. The other type, expenditure options, provides opportunity to target some of the funds toward goals that may have high social priority; for example, subsidizing hard-hit ratepayers or mitigating adverse effects on high-sulfur coal regions.

3) The revenue options entail raising part of the funds for controls based on emissions, electricity production, fuel use, the nation's tax base, or a combination of these. Costs would be spread among utility ratepayers, fossil fuel users, or U.S. taxpayers. Part of the control cost funds could still be raised through the normal ratemaking process; these revenues would supplement those funds.

4) The funds raised from these revenue options could then be used to mitigate the economic hardships caused by
### Table 4. Acid Rain Control Expenditure Options

<table>
<thead>
<tr>
<th>Option</th>
<th>Intent</th>
<th>Implications</th>
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<tr>
<td><strong>Subsidizing ratepayers</strong></td>
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<td></td>
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<tr>
<td>Subsidize ratepayers through tax credits</td>
<td>Protect individual consumers from large rate increases</td>
<td>Shift costs to Treasury, unless coupled with a revenue proposal</td>
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<tr>
<td>Compensate states</td>
<td>Prevent a few states from bearing costs of national problem; cover various social costs</td>
<td>States may choose to use funds for purposes other than acid rain controls; preserves incentives for least-cost controls</td>
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<tr>
<td>Protect high-sulfur coal regions</td>
<td>Provide standard S/ton of S02 removed subsidy for scrubbing</td>
<td>Incentive to switch to higher sulfur coal before scrubbing; some utilities will inevitably be overpaid and others not fully reimbursed; difficult to administer</td>
</tr>
<tr>
<td>Provide compensation for displaced miners and mining communities (can be couched with other programs)</td>
<td>Provide compensation and retraining/relocation assistance; deal with direct human cost of program</td>
<td>Does not reimburse high-sulfur coal companies for losses; retraining/relocation program are very difficult to design and implement; community assistance difficult, unlikely to bring long-term solution</td>
</tr>
</tbody>
</table>

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### Table 4. Acid Rain Control Expenditure Options — continued.

<table>
<thead>
<tr>
<th>Option</th>
<th>Intent</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Provide capital subsidy for scrubbing — full/partial</td>
<td>Require utilities choosing to install controls to pay only O&amp;M, not capital, costs</td>
<td>Locks plants into a control technology, leads to higher life-cycle costs</td>
</tr>
<tr>
<td>Impose scrubbing on designated power plants and subsidize capital costs</td>
<td>Women/Sikorski approach— clean up highest emitting power plants</td>
<td>Difficult to target most cost-effective plants to scrub; inefficient in that it leads to higher national control costs</td>
</tr>
</tbody>
</table>
efforts to control acid rain. Hard-hit ratepayers could be subsidized through tax credits, or heavily affected states could be compensated by grants from the fund, analogous to revenue sharing. In both cases it would be exceedingly difficult to determine eligibility and appropriate distribution formulas.

(5) The revenues could also be used to mitigate potential adverse effects in high-sulfur coal regions. These responses would be transfer payments and would not significantly distort investment incentives. It would be relatively inexpensive to compensate individual miners who lose their jobs as a result of controls (although determining eligibility would be costly). Coal industry aid to communities which rely on high-sulfur coal production for a large part of their economic base would be very costly. High-sulfur coal reserve owners are likely to request compensation for the reduced value of their reserves.

(6) One way to address all of these concerns would be to subsidize scrubbing so that high-sulfur coal production could be maintained—at least at 1980 levels. This approach could add from $200-$700 million per year to the costs of acid rain controls. These are real resource costs that they divert capital from other, more productive, uses.

Finally, designers of acid rain control legislation should consider two additional points. First, any credible proposal would have to provide sources with ten to fifteen years of lead time before significant emission reductions are required. The adjustments made between now and the target date (for example, development of new control technologies and shifts in new mine development patterns) are likely to moderate the potential adverse effect of the SO2 rollbacks. Second, acid rain controls would become a significant pollution control program. Therefore, the effects of SO2 rollbacks on other media (such as sludge disposal issues) should be carefully considered. In addition, the potential contribution of controls to other environmental goals such as attainment of the National Ambient Air Quality Standards for SO2 and particulates and protection of visibility should also be taken into account.

Notes
1. The term "acid rain" is misleading; more than half of the acidity in eastern North America results from dry deposition.
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50 states are covered would not significantly affect the comparisons in this paper.

9. The amount of revenue produced over time would increase. The rate of increase would depend on factors such as the growth in electricity demand, nuclear power development, and the availability of hydropower.


11. Based on ICF projections as of July 1983.

12. Ibid.

13. It is often argued that although eight Sw of scrubbing coupled with large-scale fuel switching may be a least-cost approach to meeting 5.0 D4, considerably more scrubbing is likely to occur. Some state governors in high-sulfur coal producing regions may resist that their utilities scrub instead of fuel switch in order to preserve local high-sulfur coal employment.

14. ICF, Inc., Analysis of a Senate Bill.

15. EPA's Office of Policy Analysis sponsored two studies which examine previous efforts to compensate displaced miners. They are: Mathematics, Inc., A Discussion of Alternative Policies to Aid Unemployed Coal Mine Workers, April 1981, and Urban Institute,Assisting Coal Miners Dislocated by Sulfur Emissions Restrictions, Issues and Options, April 1981.


17. The estimates of subsidized scrubbing effects are based on ICF analyses prepared for EPA's Office of Policy Analysis.


19. Memo prepared by Larry Parker, Congressional Research Service.

The paper on acid rain will be discussed first, and the nuclear papers will be discussed together.  

Acid Rain

Milton Russell and Stephen Brenner offer a good description of the many funding alternatives available to us in the field of acid rain control, and their discussion of advantages and disadvantages of each is most helpful. But there is a great danger of being taken in by the assumptions which are implicit, but hidden, in this paper.

Let me enumerate and then discuss just a few of these unstated but implied assumptions. (1) The paper assumes that there is a known, demonstrated, acid rain problem, that it is caused by electric generating plants in the Midwest, and we must do something about it now. (2) The paper assumes that the capital cost can be paid for at an average cost of one mil/kwh and totally ignores the operating costs. (3) The paper assumes we know where the problem is coming from. (4) The paper assumes that scrubbers and fuel switching are the only ways sulfur dioxide can be reduced and practically rules out fuel switching if it displaces any coal miners. (5) The paper assumes that the cost is independent of when the work is done. (6) And more . . . Warren Brownley suggests that since we will never have all the facts, we might as well decide now with very little knowledge.

With such a litany of implied assumptions--most of which
are incorrect in my opinion—and with only limited space available, I hardly know where to begin.

Let me start with an often-stated assumption: "There is concern about whether the effects of acid rain are more widespread than we realize." True, but we could also find that throwing billions of dollars at the problem will not solve it. Or we could find that emerging technologies will provide better solutions. Or that as nuclear plants come on line we will use the older fossil-fired plants less, or that many of our older coal-fired plants will be retired by the 1990s. The "tip of the iceberg" play is nothing more than a scare tactic designed to drive the country headlong into a massive, expensive program.

As I said, this paper does a very good job of explaining and discussing the various ways in which the capital cost only of an all-scrubber, do-it-now program might be financed.

Let us take a look at how much of the costs that would cover. A recent study by Temple, Barker & Sloan, commissioned by the Edison Electric Institute, concluded that the one mill/kwh figure is realistic in covering the capital costs—perhaps 25 percent low. But what of the operating costs? The cost of disposing of the ash? The cost of additional generating capacity to make up for the power used in operating the facilities? Temple, Barker & Sloan concluded that these costs could bring the total to $5 mill/kwh. And where is that money to come from? Presumably the ratepayers in the Midwest. A good point is made by the report where it states: "Since a national program for controlling acid rain signifies off investments from other sectors of the economy, it should be carried out as cost-effectively as possible."

Any control program, the need for which cannot be scientifically or economically justified, is going to have its greatest impact on the industrial Midwest, which is currently emerging from the 1980s. This expenditure may be mandated without any guarantee that the reduction in emissions will remedy the perceived problem. I can find very little evidence that any real thought has been given to cost-effectiveness in any of the alternatives. Moreover, the cost-benefit ratio has been given almost no study. But this is not surprising, since no one knows what the benefits will be of any of the proposals for how to spend several billion dollars.

The paper assumes that 1980 is the right base year and that 1.5 pounds/million BTU is an acceptable level below which no control is needed. Why should standards be selected so as to maximize burden on one section of the country, while the presumed beneficiaries are asked to make no contribution?

The paper assumes we know where the acid rain in New England and the Adirondacks comes from and that the emitter should pay. The "polluter pays" principle sounds good, but it is completely inexplicable—we do not know what emissions cause what—so we do not know who is the polluter.

Some would define pollution in terms of SO2 and NOx per square mile. On this basis, New York and New England should be paying most since they have the highest densities per square mile. And what of recent emissions increases in those areas compared with decreases in the Midwest?

The paper assumes there are only two ways to go—scrubbers or low sulfur coal. It suggests that Ohio and surrounding states become a "guinea pig" to see if a very expensive clean-up effort will make any difference. This is a terrible burden to put on the companies and ratepayees in one or two states.

After admitting that fuel switching is the least costly and that it would be "cheap at any price" compared to scrubbers, the paper goes on to point out that switching costs of buying miners unemployed in one region are so great that the alternative of low sulfur coal should be rejected out of hand. Again, this glosses over any effort to identify the true benefits and to measure them against the costs.

Now to the very key assumption that scrubbers are the best (or only acceptable) solution from a technological point of view: Scrubbers cannot be applied cost-effectively to older plants; a Skorski-type unit locks us into using an inefficient technology on old plants nearing retirement. The Temple, Barker & Sloan study I referred to earlier states that it would not be economic to retrofit scrubbers on pre-1960 units. Applying this to the company I represent leads to the conclusion that it would not be cost-effective to retrofit scrubbers on 12 of the 16 units from that one company on the Skorski "top 50" list.

Several new technologies, including fluidized bed combustion and coal gasification, are nearing commercial demonstration and could be used to repower these older units, accomplishing the same emission reduction as a scrubber, while extending the service life and improving the efficiency of a generating unit nearing the end of its economic life. Why is not an effort to develop these technologies more cost-effective than trying to retrofit scrubbers on units which will be 30 to 40 years old by the 1990s?

In summary, I think the Russell and Brenner paper is a good summary of the various alternatives of financing the capital cost of an all-scrubber, do-it-now program. But it completely avoids the broader questions of whether such a program is the right way to go, and it makes a very large number of very questionable assumptions about this vital subject.

Nuclear

I cannot resist a semifeasable statement which, regrettably, contains a considerable portion of truth. We
all know that the nuclear industry is in deep trouble. It seems sometimes that acid rain and other environmental and regulatory action toward the fossil-fuel industry constitute the one great hope that will bring nuclear back. Yet, the fossil people are having their troubles, too. Perhaps the failure or slowness to solve the nuclear waste and other problems in the nuclear industry will prove to be the savior of the fossil-fueled energy business!

Jean-Paul Beere's paper might lead one to feel that, perhaps, the French have found the way out of the dilemma, and we can solve our problems their way. But alas! I am afraid the French system will not work in the United States—for largely political reasons. We have gradually evolved the concepts of "core process" and "rights of the individual" to mean that almost anyone, regardless of competence, breadth of understanding, or motivation, can thwart the efforts of the nuclear power people for months or years, and at a cost now measured in the billions.

Beere told us that the French built a unit in half the time it takes in the United States. It is sad to note that the United States has cancelled its liquid metal breeder program at Clinch River, while the French have already built and operated a 1000 MW breeder and expect to open a 1200 MW breeder next year.

I agree with Beere that nuclear power is cheaper, less polluting, and safer than any other form of power generation and that the waste is easier to handle, because of the smaller volume.

Many of the lessons learned in France do not apply in the United States, but a close study of standardization has numerous appeals. Although we could not standardize on a single vendor, we should at least consider one reactor concept per vendor. But our biggest problem is constantly changing regulatory requirements that do not even permit us to build one plant like its identical twin! Constant changes are killing us economically.

What is the payback time for a breeder that produces usable power? This is the ultimate question. Some time last year I heard someone say that the power would begin rolling off a breeder plant in Florida in 1983. That is beginning to look a little bit far away.

Turning now to the paper on nuclear waste disposal, I agree wholeheartedly with Howard Perry that one of the most significant actions of Congress in 1982 was passage of the Nuclear Waste Policy Act. The consensus among the portion of the electric utility industry involved in nuclear power is generally positive toward the act. We have some reservations about this provision or that implementation step, but on the whole we are glad that the law was enacted and that the Department of Energy is proceeding to make it work.

Most of us, including, as I understand, Perry, have felt for years that accomplishment of nuclear waste disposal is less a technical problem than it is an organizational and institutional problem—and a public acceptance problem. The engineering solutions are known and available. The programs that Perry has described are aimed at choosing among them. We applaud those efforts and encourage that they be carried out with completeness and also with expedience. If anyone is asking for the industry's advice on implementation of the program, it is this: Get on with the job.

I am a little bit chagrined to see that the law, signed into effect in January 1982, prescribes that DOE will first accept nuclear waste for disposal by January 1988. Fifteen years later. I do not fully understand why, following 25 years of research on the subject, it will take another fifteen years to achieve results. Surely, it is not for technical reasons.

I am, perhaps, more chagrined to see that one of the very first of the interim deadlines leading to the establishment of repositories, the issuance of Site Selection Guidelines, has been slipped from six months into the program to twelve or perhaps even fifteen months into it. More important, the selection of the first repository site has slipped from the March 1983 target date to December 1990, or more than three years according to the draft DOE Mission Plan issued in December 1983. I sincerely hope that this elongation of the schedule is not a precursor of future activity. I recognize that DOE's failure to meet that deadline is a result of their commitment to doing a superlative job. But, we must get on with the job. Part of doing a superlative job is getting it done in a timely manner, particularly when the consequences of delay could be paralyzing to a vitally needed industry.

Some utilities have major problems of this nature today, and many others will follow shortly. It would be unconscionable, but it could happen, for a nuclear unit to be shut down because there is no place to put the partially spent nuclear fuel in its core. As Perry said, DOE is working with several utilities to develop and license on-site facilities and is authorized to provide away-from-reactor federal interim storage. Again, technology is not the problem and my excoriation to DOE is: "Let's get it done."

Many feel that a Monitored Retrievable Storage facility for nuclear waste is desirable. In fact, retrievable is a key word and nuclear waste is a misnomer. When spent nuclear fuel is removed from a reactor, there is a very substantial amount of valuable energy still remaining in it; it is hardly waste. To make that energy available for use, the spent fuel should be reprocessed—separated into a volume of reusable nuclear fuel and a smaller volume of actual waste. Presently, there are no operating reprocessing facilities in this country, and there are no plans to establish any. But someday that may change, and in an environment that values highly the conservation of energy resources, we should not foreclose our options. A storage option which allows retrieval of spent nuclear fuel is clearly a prudent conservation action.
In summary, I am heartened by the actions of Congress and President Reagan in establishing the new law and national policy. But the jury is still out on implementing it. The scientists and engineers have done their job and stand ready to do more. Responsibility now lies with the government—-the executive branch must execute. The whole nuclear industry would like to see the program put in place as soon as possible, even in advance of the fifteen-year deadline established by statute as the outside limit. We can if we will. Let us get on with it.

COMMENTS

Warren H. Donnelly

Jean-Paul Emer, Howard Perry, and Milton Russell and Stephen Bronner addressed three topics: foreign nuclear power development, nuclear waste disposal, and the problem of social cost. What do these have to do with the workings and interests of state public utility commissions and their staff? The relevance as seen by this commentator will now be discussed.

The fate of nuclear power for some utilities in the United States is becoming bleaker. In early April 1984, Frank Zarb called for a presidential commission to cure the ills of nuclear power and to develop "an acceptable framework for nuclear development—-or dismantle it." For him, "federal intervention in the nuclear power sector is essential to bring some order out of this mess." The Niagara Mohawk Power Corporation has announced that the cost of its Nine Mile Point nuclear plant has jumped 21.4 percent in little more than a year. The Long Island Lighting Company's auditors noted in its annual report that Lilo could be found in default of $600 million in loans if the company did not resume its payments for Nine-Mile Point, at a time when Lilo already was struggling with the immense cost overrun of Shoreham. Public Service of New Hampshire is facing strong opposition

Note: The following views are those of the author and do not represent those of the Congressional Research Service.
to start-up of Seabrook—in part because of fears for a great increase in rates as its great capital cost is factored into the ratebase. Barry S. Zitter, Consumer Counsel for the State of Connecticut, writing in Public Utilities Fortnightly, recently observed there is no painless solution to the nuclear dilemma. Three parties inevitably have to pick up the costs of nuclear power: some combination of taxpayers, ratepayers, and utility investors. He would have the federal government finance any nuclear unit under construction which is more than half completed.  

So nuclear power, its costs, and its fate are matters of current substantial concern to many public utility commissions, which brings us back to the papers under consideration. At first glance it might seem they are an odd lot: two on aspects of nuclear power and one on acid rain. Yet this assortment proves stimulative of thought. Russell and Brenner in treating regulations for acid rain and the financing of their implementation had things to say which are directly pertinent to the nuclear problem. They reminded us that whether or not we like it, decisions by public utility commissions must be made without all the scientific information needed for a completely rational decision, and in the presence of uncertainties, in the case of nuclear power, uncertainties abound about its long-term future, the effects of further charges in government policy, the performance of the plants, their safety, the meshing of future needs for spent fuel disposal with provision of facilities to do so—too many. They anticipated Zitter's point that the costs of regulatory decisions inevitably have to be paid by someone, with the only variable being the distribution among ratepayers, taxpayers, and investors.  

Brenner presented an optimistic picture of nuclear power in France, which seems to have few of the trials and tribulations so evident in the United States. His account conjured up visions of greener nuclear power in la belle France. Just think of it. Nuclear power plants built close to schedule and budgets, reliably producing more electricity per kilowatt-hour of generating capacity than comparable plants in other countries, and at costs which French accounting firms find to be less than others sources. Not only that, but industrial rationalization has achieved its ultimate goal as one utility—Electricite de France—produces and distributes all of the electricity under central rate making. Government policy offers an attractive discount to attract new industrial users as France pushes a policy of electrification and nuclear power, which it hopes will give it a substantial competitive advantage in international industrial trade.  

Brenner's explanation for this happy state of French affairs saw virtue in France's strong, active government commitment to nuclear power; its single supplier of nuclear plant and equipment—Electricite de France; and EDF's strong policy of standardization in nuclear power plants. But we must live in our own pasture, and is that of France really so verdant? To recall an old saw, which still has teeth: "it all depends." Think for a moment of what the French approach would mean for public utility regulation here. How would 50 state public utility commissioners like to try to regulate a single, monolithic, government-owned electrical utility? Indeed, would there be any state commissions? How would the economic ideals of this country square with the idea of a single U.S. supplier of nuclear plant and equipment—a single Westinghouse or General Electric? How would state regulators respond to a centrally imposed policy to go nuclear for reasons unrelated to economics, namely, to increase national energy security and decrease imports of oil? The implicit answers to these questions may not solve admitted U.S. problems with the economic regulation of nuclear power, but they do show that the French system is no model for us and our circumstances. And that French greener pasture upon closer examination has some rocks in it. Brenner did not say what is to be done with the spent fuel from EDF's nuclear power plants. Presumably, the French plan to use it as a source of plutonium for their continued development and demonstration of breeder reactors and perhaps as a supplementary nuclear fuel for conventional nuclear power plants. Indeed, the French already have the foundation for a commercial reprocessing industry. Many in the United States think the French are fooling themselves with their present price for reprocessing services, that the true cost will be much higher and uneconomic. There is also the question of who pays what part of the total cost. Apparently, the French would have the utilities pay all of the cost of reprocessing as a waste management cost. This would mean that the recovered plutonium would virtually be a free byproduct which could be priced to compete with enriched uranium whether for domestic use or for export. Imagine, for example, the regulatory problems if we were argued that the price of the plutonium should reflect the cost of reprocessing. What splendid economic controversies would blow over how to apportion the costs of reprocessing between the charge to the utilities that supply the spent fuel and the price charged to buyers of the recovered plutonium. Despite trustful French optimism, there remains a real possibility that, like the ill-fated Concorde project, France may succeed technically but fail economically with commercial production and use of plutonium for fuel. If so, this would leave EDF in the future saddled with high costs of capital sunk into uncompetitive reactors. Of course, the French might succeed and attain world leadership. Moreover, the French seem far more relaxed than many in the United States about fears that
commercialization of plutonium would spur the spread of nuclear weapons and explosives, perhaps even into the hands of terrorists.

Perry's silence on French provisions for long-term disposition of spent fuel, if the reprocessing option fails, brings us to Perry's remarks on spent fuel disposition in the United States. Perry described in optimistic terms the good works intended by the Department of Energy as it takes up its responsibility to site and build a repository for spent fuel. He gave a good summary of the Nuclear Waste Policy Act and outlined the many steps that will have to be accomplished if DOE indeed is to be ready to accept spent fuel by 1998. This is only 14 years away, scarcely more time than it now takes our combined industrial-financial-regulatory-judicial system to start and finish a large nuclear power plant. During this time some twenty major decisions will have to be made, favorably, by various federal agencies, only one of which has any responsibility for opening the storage site on time. Also during these few years, improved technologies will have to be demonstrated, sites selected and confirmed for demonstration, public fears and active opposition allayed, and state governments persuaded not to use their veto powers despite the great force of NIMBY (Not In My Back Yard). From the standpoint of predictability, the process that is supposed to produce this national waste storage repository is fraught with uncertainties. Clearly, the highest caliber of management and political acumen is needed if this undertaking is to arrive safely and on time at its intended destination. In the meanwhile, the one million per kilowatt-hour fee on nuclear generation will pour millions of dollars into the federal treasury, a fee that must be added to the costs of generating nuclear power.

What does all of this mean to the regulators? It means long-term uncertainty as to ultimate costs of spent fuel disposal, until there is nuclear power. Certainly, it would be nice to have this federal facility available on schedule. However, if it is delayed, the sky probably will not fall or even slip very much. The new manufacturers are advertising the availability of costs for the dry, surface storage of older spent fuel. By the 1990s the economics and safety of this mode of storage should be well demonstrated and perhaps here. If the federal repository falls behind schedule, the utilities could store more spent fuel on site by using this technology, assuming NRC approval. So if worse should come to worst and the repository were not available, the state commissions would face comparatively minor rate increases to cover the capital and operating costs of this supplementary storage method. Yet, both they and the NRC could expect intense pressure from nuclear opponents not to permit such supplementary on-site storage.

One matter that Perry did not cover which could prove to be the Achilles' heel for central waste storage is the possibility of successful legislation or litigation to block the transport of spent fuel from utility sites to the repository. Looking ahead, in spring 1984 there are few signs that the order of nuclear opponents is likely soon to cool. They can be expected to try to stop the movement of spent fuel, and the past history of interventions would give them some hope of success. Yet, many justices of the Supreme Court may be replaced because of age during the next few years, perhaps leading to a more conservative court if the Reagan administration remains in office; such a court presumably would be less likely to support such interventions, and thus reduce the prospects of success for those opposed to central waste storage. Neither did Perry touch upon the question of where the utilities will dispose of the radioactive junk and debris from the future decommissioning of nuclear power plants. That matter merits the attention of a future panel.
activity, what should be their attitude? Passivity and after-the-fact response, or anticipatory? Should regulators simply accept new technological advances as they occur in power generation and distribution, in pipeline operations, in telephone service? Or can they and should they try to look out along the trendlines to see what the effects of technological change may be upon the public? Should they try in advance to influence these trends into better directions? A heady and controversial thought is it not? Still, if the technologies which the commissions regulate change, sometimes drastically, why should the regulatory regime itself escape corresponding change?

So the ultimate meaning of these three papers is another reminder that change and uncertainties are inevitable, must be lived with, and will tend to reshape the work of the regulatory agencies. Look to the future. You might like it, especially if you can help shape it.

Notes


Part Nine:
Natural Gas: Changing Market Boundaries, New Entry, and Interfuel Rivalry
The natural gas industry is currently confronted with a surplus supply of natural gas. This surplus relates to deliverability rather than reserves. The incentive prices under the Natural Gas Policy Act (NGPA) and the availability of markets initially stimulated a high level of well drilling activity. Unfortunately, this activity was directed primarily toward developmental wells with the consequence that we were unable to produce existing reserves more rapidly than find new reserves. Data prepared by the Energy Information Administration (EIA) for 1982 indicate that we barely replaced production despite a depressed market for natural gas.\(^1\) It is currently estimated that our surplus deliverability may range from 3-4 Tcf.

Reduced demand for natural gas has also contributed to the surplus supply. This reduction resulted from a number of different factors, including conservation on the part of consumers, a general slowdown in the economy, improved technology, and fuel switching. The American Gas Association (A.G.A.) has reported that industrial sales during 1982 were 17 percent below the 1981 level, and residential and commercial consumption remained about constant due largely to load additions. Absent these additions, residential and commercial consumption also would have declined in 1982. It may be noted that residential and commercial consumption declined the first eight months of 1983, and industrial consumption declined more than 20 percent during the same period as compared with 1982 experience.\(^2\) This decline in industrial...
consumption occurred at the same time that some economic recovery was taking place. Rising gas prices and the availability of low priced alternate fuels, particularly residual fuel oil, have contributed to the drop in industrial demand for natural gas.

As a consequence of the energy shortage in the early and mid 1970s, industrial and power plant loads undertook to develop the capability to use alternate fuels. The A.D.A. has estimated that approximately 21 percent of all gas used in the United States is consumed in facilities with dual-fuel capability. Declining world oil prices and an abundant supply of fuel oil, particularly residual fuel oil, have made fuel oil competitive in many markets. At the same time that oil prices have been dropping, natural gas prices have continued to rise due to several factors: (1) automatic escalations provided under the NGPA, (2) contractual provisions negotiated shortly after enactment of the NGPA, (3) the amount of incentive-priced and deregulated gas that has become available, and (4) depletion of lower priced supplies. Today, many pipelines and distributors find it difficult to compete with residual fuel oil. Consequently, the pipelines have sought to implement programs to retain and regain markets that can use residual fuel oil. Certain of these companies have also proposed programs that would result in gas-for-gas competition, and some would use gas pricing as a means of improving the marketability of the end products. It is possible to gain some understanding of what is occurring in the marketplace by reviewing these different programs. They can be grouped into four major categories: (1) changes in remaking, particularly rate design; (2) special discount rates; (3) industrial sales programs; and (4) special producer sales programs.

Remaking

Remaking as practiced by the FERC has three fundamental objectives. (1) Enable pipeline companies to recover costs and earn a reasonable return on investment. (2) Equitably apportion costs among the different services provided. (3) Design rates that will achieve the FERC's policy goals and objectives. Consequently, the commission's remaking methodologies have varied with the conditions and circumstances that prevailed at the particular time. Some of the more important factors that have influenced remaking have been capacity constraints, supply constraints, and the marketability of natural gas for particular purposes.

When there were capacity constraints in the 1960s, the commission employed the fixed-variable approach to send signals to those that would impose additional capacity requirements as to the true cost of that capacity. When the commission became concerned that certain loads were receiving a free ride, it employed the Seaboard methodology of remaking, which shifted 50 percent of the fixed transmission and storage costs to the commodity charge to assure that all natural gas users bore some of the capacity costs. When the Seaboard methodology was employed to send signals that discounts were going to be less for those high load factor consumers of natural gas. Throughout this period the commission recognized the important contribution that industrial consumers make to the efficient operation of the pipeline systems.

Recently, pipelines and distributors began to experience difficulties in marketing natural gas, particularly to those end-users with alternate fuel capability. Consequently, the pipelines proposed changes in their remaking methodologies. These generally took the form of reduced costs included in the commodity charges of their two-part rates. The proposals have varied among companies, but essentially they have reflected the recovery of average purchased gas costs, fuel costs, a portion of return of and on equity, and associated income taxes in the commodity charges. These proposals have been characterized as modified fixed-variable approaches.

The FERC has recognized the changing competitive situation in the marketplace and has accepted changes in remaking methodology. In a series of orders issued February 15, 1986, three pipeline companies were permitted to develop their rates using the Seaboard methodology in lieu of the United States methodology. A rate settlement involving Northern Natural Gas Company was accepted which embodied a modified fixed-variable approach. On November 4, 1983, the commission approved, based upon a formal hearing record, a modified fixed-variable remaking methodology for Natural Gas Pipeline Company of America.

These changes in remaking methodology have the effect of reducing the pipeline companies' commodity charges, which improves the competitiveness of natural gas in the marketplace, assuming the distributor customers employ similar techniques. However, as purchased gas costs have continued to rise, the weighted average cost of gas to some pipelines has tended to be at or near the cost of alternate fuels. This has made it difficult for the pipelines and their distributor customers to compete for industrial and power plant loads with alternate fuel capability. This has given rise to suggestions that gas supplies might be segregated in order to make gas more competitive. However, these suggestions present difficult problems: Less price sensitive consumers would be required to assume the burden of higher priced gas supplies and could be required to assume a greater share of capacity costs.
The major question remains to be answered: Would all consumers benefit from discriminatory pricing being made available to the more price-sensitive loads? While the commission has not specifically addressed these suggestions, it has expressed a willingness to do so.

Special Discount Rates

Marketing difficulties have caused certain pipelines to seek to implement special discount rates in order to retain or regain loads. These proposals have not limited their applicability to loads with residual fuel oil capability. Rather, they have tended to be directed toward any market with alternate fuel capability, regardless of the type of alternate. In certain instances the proposals have been designed to reduce the cost of the end product, thereby making it more competitive. The pipelines have attempted to demonstrate a net benefit to all customers and consumers by showing take-or-pay relief and fixed-cost contributions as the result of sales that would not otherwise be made.

The commission granted temporary authority to three pipeline companies to reduce their sales prices subject to certain conditions: (1) the sales were limited to terms of six months; (2) there must be stated rates that would recover at a minimum the average cost of purchased gas plus any out-of-pocket costs; (3) the service would be available for uses where residual fuel oil was the alternative; (4) the final determination of the appropriate rates was to be made in pending rate cases; and (5) any undercollections between the rates charged and the rates determined in the rate proceedings could be imposed upon the stockholders. One company, Columbia, ultimately declined to accept the temporary certificate, but both Michigan Wisconsin and Northern made discount rate proposals received commission authority to continue such sales pending disposition of its permanent certificate. Three other companies proposed discount rates but withdrew the proposals in the face of opposition from their customers.

The certificate applications of Columbia, Michigan Wisconsin, and Northern were set for hearing by orders issued December 23, 1962. The orders indicated that the proposals raised both short- and long-term policy concerns and instructed that the proceedings specifically address such matters as: (1) the effect upon these customers unable to take advantage of the program because of their market characteristics; (2) the extent to which such prices would affect gas acquisition practices; (3) whether these sales convey proper market signals. The commission was concerned that these sales could increase the cost of gas to all customers depending upon whether it was necessary to purchase high priced supplies in order to make the sales. Also, they could result in the depletion of lower priced attached supplies, which would ultimately drive up the costs to all customers. If the special discount rates enabled gas to be sold and tough decisions were avoided on ways to make field prices more responsive to the market, then the commission could be responsible for delaying the solution to market-ordering problems.

The FERC has not finally resolved its approach toward special discount rates. Certainly, rates that favor price-sensitive consumers must be evaluated in the context of their effect on other less price-sensitive consumers. It is not a given that discriminatory rates are always bad. If those rates can be shown to contribute a net benefit to the pipeline system and all customers, then they should be seriously considered. The difficulty is showing a net benefit, and that has been the main purpose of the proceedings involving the permanent certificates.

Industrial Sales Programs

As competition has become more intense, the pipelines have found it necessary to develop new and sometimes innovative approaches in order to market gas. These have been given impetus by increased take-or-pay exposure and declining sales. The pipelines suddenly found that their earnings were being eroded by declining sales; yet, if they held to increase their rates, they would experience further declines. The difference in price between natural gas and alternate fuels had become so narrow in some markets that virtually any increase in gas price triggered a negative demand response.

The first pipeline to attempt a response to this situation was Transcontinental Gas Pipe Line Corporation (Transco). It was experiencing declining sales, rising costs (particularly purchased gas costs), and rapidly increasing take-or-pay exposure. It had previously marketed-out under its higher priced contracts and found that the authority to do so. During settlement negotiations on its general rate cases in Docket Nos. RP83-11 and RP83-30, a proposal evolved whereby Transco would take certain steps. (1) Supply and demand would be balanced by a pro rata reduction in purchases from all suppliers regardless of pricing category and take-or-pay obligations. (2) Monthly posted prices would be established to enable its customers to compete with alternate fuels. (3) The supplies released by Transco could be sold directly to its distributor customers for eligible end-users, and Transco would act as agent for the distributors. (4) The volumes sold under the program would be transported by Transco at the applicable commodity charge exclusive of gas costs and fuel. (5) The volumes sold would be considered gas purchased under take-or-pay obligations. This part of the proposal...
was identified as its Industrial Sales Program (ISP). Transco also proposed to implement a transportation program, or CCP, whereby it would transport gas purchased directly by its distributor customers if the liquids could not otherwise be served under the ISP or other Transco rate schedules. The entire proposal was tendered to the FERC as part of the rate settlement and was accepted by letter order issued April 28, 1983.

The necessary certificate authority for the ISP was issued on June 27, 1983. In the meantime, Transco had implemented the program where abandonment authority was not required. During May 1983, roughly 160,000 dekatherms per day were delivered under the ISP, and in June the volumes increased to 190,000 dekatherms per day. In July 1983, Transco filed for the necessary certificate authority to implement the CCP, and authorization was granted on September 29, 1983. The Transco program was experimental and expired on October 31, 1983. By order issued November 30, 1983, the commission permitted the program to continue through March 31, 1984.

The Transco program was designed to achieve several objectives: (1) bring supply and demand into balance. (2) Maintain the historical level of throughput on its pipeline system. (3) Keep natural gas prices competitive with the prices of alternate fuels. (4) Enable its producer-suppliers to market gas. (5) Relieve it of take-or-pay exposure. (6) Enable it to compete with other sources of gas supply.

Other pipelines have proposed similar programs. Columbia, Panhandle, Tennessee, Trunkline, and United have proposed programs based upon their particular circumstances. The Columbia program has been approved with some modifications; the Panhandle, Trunkline, and United programs have been set for hearing before the commission. Each of the programs involves transportation by the pipeline and the commission has taken certain actions to facilitate transportation of natural gas. By orders issued July 20, 1983, blanket permits were implemented permitting transportation on behalf of interstate pipelines, intrastate pipelines, local distribution companies, Hishaw pipelines, and end-users. The commission also included an incentive allowance to encourage the transportation for end-users. It is expected that these procedures will make it easier to move gas into the marketplace at competitive prices.

Special Producer Sales Programs

As natural gas sales have declined, producers have begun to look at unconventional markets. Many of them have participated in the pipelines' industrial sales programs, and others have expressed a willingness to do so. In June 1983, Tenneco Oil Company along with four of its affiliated producers proposed a spot market sales program identified as Tennenex. DEG gas produced from new leases, new reservoirs on old leases, and wells qualifying under Section 109 would be available to any willing purchaser. The prices would be determined monthly on the basis of competitive bids, but in no event would they exceed the applicable maximum lawful prices (MLPs). The Section 109 gas would only apply to gas reserved for the producer's own use. The program would extend through December 31, 1984.

The Tennenex proposal generated extensive opposition from inter- and intrastate pipelines, local distribution companies, and even some producers. At an informal conference Tenneco attempted to respond to this opposition by offering five conditions which it would find acceptable. (1) Transportation of the Tennenex volumes would not disrupt transportation of pipeline system supplies. (2) Prices would not exceed the lower of the MLP or the contract price for released gas. (3) The purchaser must certify that existing purchase contracts do not prohibit purchase of Tennenex gas. (4) Tennenex volumes would only displace alternate fuels or other nontraditional sources of supply. (5) Uncommitted gas would be limited to 25 percent of total volumes sold under Tennenex.

By order issued November 10, 1983, the commission conditionally approved the Tennenex proposal. It was encouraged that a producer was willing to respond to market conditions by offering to sell gas at competitive prices. It also felt that this competition might ultimately have the effect of driving some prices generally. Nevertheless, the commission had some concerns that Tennenex might be disruptive in the natural gas market. Consequently, it imposed certain conditions. (1) The Tennenex gas could only compete for marginal markets. (2) Only released gas from new leases and from new reservoirs on old leases was eligible for sale. (3) No gas could be released by a jurisdictional pipeline unless the weighted average cost of the released gas was equal to or greater than the pipeline's weighted average transportation cost of gas. (4) Any gas sold had to be in the same proportion of pricing categories as the released gas. (5) Any gas sold should operate to reduce take-or-pay obligations. (6) Any pipeline transporting the gas should recognize it for minimum bill purposes. (7) Pipelines should charge their fully allocated costs for transporting the gas.

The commission also imposed monthly reporting requirements and provided for monthly conferences to evaluate whether its purposes and objectives were being met. It reserved the right to make changes or even terminate the program if circumstances warranted. The commission was concerned that the program not result in market raiding to the detriment of those customers and consumers unable to participate.
Conclusion

Natural gas prices have risen to the point at which the market is no longer able to absorb further increases. This is particularly true for these market sectors which can use alternate fuels such as residual fuel oil and coal. But it is also true for those sectors less able to substitute alternate fuels for natural gas. Demand by residential and commercial consumers has proven to be more inelastic than anticipated. The pipelines have attempted to respond by stabilizing their costs of purchased gas, and some have implemented cut-back programs designed to reduce their purchased gas costs. Others have delayed or even forgone rate increases to avoid loss of additional loads. While changes in ratemaking and special discount rates have been proposed, there is general recognition that there are limits to the costs which can be shifted to less price-sensitive consumers. The industrial sales programs also have had as an objective the stabilizing of purchased gas costs that would be borne by system supply customers, and there has been an expressed desire that the price signals emanating from the programs will lead to more market-responsive prices for all classes of consumers.

For those consumers who can use residual fuel oil, there is no longer a price differential between natural gas and residual oil. Consequently, the choice of a fuel depends largely upon the economics, as affected by relative efficiencies, storage capabilities, delivery frequencies, and air quality constraints. Through various programs, the pipelines are attempting to respond to the competitive situation, and the commission has generally looked favorably upon these efforts so long as they are not detrimental to other consumers.

Perhaps the most difficult aspect of the competitive situation is gas-for-gas competition. Many of the pipeline proposals and the Tennessee plan would permit competition with other gas suppliers. From a theoretical viewpoint this type of competition should result in lower prices to those end-users able to avail themselves of the competition and should result in more efficient use of pipeline and producer resources. Yet, it has the potential for shifting costs to other categories of end-users and could jeopardize the economic viability of certain pipelines and distributor operations. As a regulatory agency the FERC must be concerned with both the benefits and detriments. Its concerns must extend beyond the segment it regulates because its actions will affect producers, distributors, intrastate pipelines, and end-users. Thus far, the commission has permitted competition for the so-called marginal markets. However, this is a matter of continuing consideration by the commission, and the final word has not yet been spoken. Whether and to what extent the commission permits an expansion of gas-for-gas competition depends on its perception of how the public interest can best be served.

Notes


7. 25 FERC 61,176.

8. Ibid., p. 16.


11. By order issued December 20, 1983, the FERC approved with some modifications the proposed SMP of Tennessee Gas Pipeline Company which had been identified as Temper. An order on rehearing was issued on March 23, 1984, and by letter dated April 23, 1984, Tennessee declined to accept the certificate authorization.

By order issued March 19, 1984, the FERC approved with some modifications the proposed SMP of Panhandle Eastern Pipe Line Company and Trunkline Gas Company which had been identified as PanMark Gas Company. Requests for rehearing had not been addressed on their merits by the end of April 1984.

On January 16, 1984, FERC issued a Notice of Inquiry to obtain comments and suggestions as to changes that
might be appropriate in its approach toward Special
Marketing Programs. The comments as well as the public
hearing record are currently under consideration by
the commission.

12. Order Nos. 319 and 234-B; Order on Rehearing issued
November 3, 1983.

REGULATORY IMPLICATIONS OF
CHANGING NATURAL GAS PRICE ELASTICITIES:
AN EMPIRICAL STUDY

Virginia K. Sheffield

This report presents a summary of an econometric study
and estimation of the relationship between yearly per customer
usage of natural gas in Iowa and the factors affecting that
usage. The empirical results are based on ongoing analyses
of such relationships by the staff of the Rates Research
and Policy Division, Iowa State Commerce Commission. The
purpose of the report is threefold. (1) Estimate, in total
and by customer classification, regression coefficients that
can be used to predict the extent to which natural gas usage
per customer in Iowa is expected to be affected by changes
in real retail and real wellhead prices of natural gas. (2)
Provide an understanding and empirical estimate of the degree
of influence various factors such as changes in income,
weather, and other prices have on the demand for natural
gas by customer classification. (3) Ascertain what implica-
tions the empirical findings hold for natural gas pricing
policies of gas companies and for regulatory bodies.

A major focus of the study is on the effect of gas price
changes, that is, real price changes at the retail and wellhead
level, on the annual per customer consumption of natural
gas by general customer classification. The estimation of
the gas price effects separate from other influences neces-
sarily requires the simultaneous estimation of the consumption
effects of other factors, such as income changes, changes
in the prices of related goods, and changes in weather condi-
...
tions. For the purposes of this study, per customer usage data have been classified by general type of customer: residential, commercial, industrial, and total. The remaining classification, "other," was not used because this residual classification has generally been phased out and now includes few customers and volumes.

The theoretical model applied is the classical economic theory of derived demand: Consumers maximize utility subject to a budget constraint, while prices and income facing the consumer are assumed to be fixed at that point in time. The decision of the consumer then is what quantity or what mix of different goods and services to purchase. However, that decision will always be a function of relative prices, of real income (the budget constraint), and of individual tastes and preferences. Thus, demand is a derived function:

\[ q_j = f \left( a_1, a_2, \ldots, a_n, \frac{P_j}{P}, \frac{P_j}{I}, \alpha_j \right) \]

where

- \( q_j \) = quantity of the jth good demanded;
- \( a_j \) = price of the jth good;
- \( g \) = the indexed price of all goods;
- \( P \) = income; and
- \( \alpha_j \) = the jth preference factor.

The total demand across the economy for any single good is the summation of individuals' demand for that good.

Viewing the theoretical model, it is evident that demand is responsive to four types of factors: (1) changes in the price of the good or service under study (own-price effects); (2) changes in the price of related goods and services (cross-price effects); (3) changes in income (income effects); and (4) changes in tastes and preferences, including technological changes. The first effect is referred to as a change in the quantity demanded, that is, movement along the demand curve which describes the relationship of price and quantity. The other three are referred to as changes in demand and cause movement or shifts of the demand curve in relation to the axis. Each effect is measurable in terms of elasticity, that is, the percentage change in the quantity of natural gas demanded gives a percentage change in one of the influencing factors.

Until recently, the prevailing belief of those acquainted with the natural gas industry and market has been that the relative price elasticity is negative and small in value, between -1 and zero. Thus, the real price of gas increases by a certain percentage, the demand for gas decreases, but by a smaller percentage. This own-price elasticity for the residential market and for other small-scale users has generally been presumed to be so small as to be insignificant in the consideration of consumption responses to changes in gas prices and pricing policies. Large users are generally thought to have more fuel switching options and more incentive to invest in conservation strategies than do residential and other small users simply because of their absolute size and volume of energy use. That is, the economies of scale for investing in alternate fuel capability and energy efficien-
cy devices or conservation measures are assumed to be better given large volume natural gas use; thus, the own-price response for some commercial and most industrial customers is presumed to be relatively more elastic. The belief in the insufficiency of price influences on the demand of the residential sector of the market has been used to support pricing policies that shift or place the burden of costs on the residential class for fear of a significant consumption response due to a price increase in the industrial, large-volume market.

The study was conducted to challenge the belief of minimal demand reaction on the part of residential customers to changes in natural gas prices and in related factors. The results stand as a warning to the industry that further price increases or disproportionate shifts of costs to this customer group could substantially reduce aggregate demand and cause revenue losses just as surely as in the large industrial usage case. Given that the financial condition of many gas companies is critical, such losses could mean disaster. The following analysis of the empirical data is presented in evidence of the degree of market response shown by residential as well as commercial, industrial, and all natural gas customers.

The Data Base

The data are pooled cross-sectional, time series, calendar year data for 1969-1982 collected for each of the eight major Iowa natural gas distribution utilities (Interstate Power Co., Iowa Electric Light & Power Co., Iowa-Illinois Gas & Electric Co., Iowa Power & Light Co., Iowa Public Service Co., Iowa Southern Utilities, North Central Public Service Co., and Peoples Natural Gas). Those eight, served by one or more of three pipelines (Northern Natural, Natural Gas, and Michigan-Wisconsin), account for approximately 97 percent of all Iowa sales and customers of natural gas distribution utilities. All price and income data have been adjusted to real [1987 base] terms, deflated by the Consumer Price...
Index--Wage Earners (CPI-W). In the case of oil prices and conservation measure prices, the appropriate federal price index for the good was used.

Retail price and consumption data were available from IG-1 and IE-1 reports filed annually by the utilities with the ISCC. These include (1) annual retail natural gas revenues and Mcf and retail electricity revenues and kwh by utility for each major customer class (residential, commercial, industrial, and other, which includes electric generating plant usage); (2) number of retail natural gas customers and electric customers by year, by utility, and by customer class; (3) annual retail real natural gas and electric prices by utility, by customer class, determined as average prices by dividing gas or electric revenues by sales in each class Mcf and kwh, respectively, and dividing the CPI-W; and (4) annual average gas and electric use per customer by utility, by customer class, determined as average use in Mcf and kwh by number of class retail gas customers and electric customers, respectively.

Average wellhead prices of natural gas by utility, by customer class, were somewhat more difficult to obtain; nearly all Iowa distribution (retail) utilities purchase gas from more than one transmission (pipeline) utility. Therefore, for each customer class for each distribution utility, the percentage of natural gas originating from each pipeline was determined. Average yearly wellhead purchase prices were then generated from each transmission utility, deflated by the CPI-W, and weighted by the above percentages to obtain a weighted real wellhead price of gas for each retail customer class, for each utility, for each year.

Annual per capita personal income by county were taken from the Survey of Current Business (Bureau of Economic Analysis, U.S. Department of Commerce) and deflated to real terms by the CPI-W. The per capita personal income for a given utility thus reflected weighted averages of the income figures by the counties in its service territory. Since detailed county income data were not available for 1981, the statewide annual percentage change in per capita income was applied uniformly across all utility service areas.

Yearly heating degree days (HDD) from temperature readings at eighteen weather stations around the state were used, weighted by individual utility sales in each region, to compute a representative measure of HDD for each utility. Yearly real fuel oil prices are reflected by the Bureau of Labor Statistics index of #2 heating oil prices. The price of installing conservation measures is represented by the component index, major housing maintenance and repairs, of the CPI-W. Since most residential conservation measures involve plumbing, electrical, or other construction services and supplies, the index is believed to be an acceptable proxy for an actual price history of specific residential conserva-

Changes in Usage, Prices, and Income between 1970 and 1982

Over the period 1970-1982, considerable change occurred in per customer natural gas usage in Iowa as well as in the economic variables which may be affecting that usage. As a base year for comparison, 1970 was selected to minimize the effect of the HDD differential between 1969 and 1982 and because 1969 data are not complete for all distribution companies.

The experience of Iowa Electric Light & Power Company, as an example, is instructive. As can be seen in Table 1, over the period both real retail and wellhead gas prices rose while both total and per customer gas consumption fell for all customer classes. The experience of other Iowa utilities was similar. For Iowa gas utilities as a whole, the comparison between 1970 and 1982 is shown in Table 2. It is of interest that during that same period heating oil prices increased dramatically, by more than 500 percent, while general prices reflected by the CPI-W increased 1.5 times, energy conservation measure prices (heating repair and maintenance) increased slightly more than two times, and real income grew at a modest 12 percent statewide. As a further comparison, shown in Table 3, Iowa average actual and real gas prices are compared with the U.S. figures by customer class, for 1980 and 1981. While retail prices in Iowa remained slightly below the national average, the percentage increase in price from 1980 to 1981 was greater in Iowa than nationally.

In summary, considerable change occurred after 1969 in the market for natural gas and in the markets for gas substitutes, in particular #2 fuel oil and energy conservation measures. The next task of the study is to identify why natural gas usage per customer has changed.

Customer Usage Response to Changes in Real Retail Price

Comparison of the 1970 and 1982 data clearly shows that, with very similar weather conditions, natural gas usage per customer has fallen across all classes of customers, while retail prices have increased rather dramatically. During the same period, relatively small increases in real per capita income and real electric prices were experienced, while the real prices of the substitute goods, #2 heating oil and conservation measures, quantified by the federal price indices, increased many times. This section reports the empirical estimates of annual per customer demand for natural gas as a function of real
### Table 1. Iowa Electric Light and Power Co., 1970 Compared to 1982, Real 1967 Dollars

<table>
<thead>
<tr>
<th>Variable</th>
<th>1970</th>
<th>1982</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas, residential</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>13,508,899</td>
<td>12,996,438</td>
<td>- 1.79%</td>
</tr>
<tr>
<td>Customers</td>
<td>81,856</td>
<td>103,034</td>
<td>25.87</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>165.0</td>
<td>126.1</td>
<td>-23.58</td>
</tr>
<tr>
<td>Real retail price/Mcf</td>
<td>$0.054</td>
<td>$1.603</td>
<td>96.93</td>
</tr>
<tr>
<td>Real wellhead price/Mcf</td>
<td>$0.141</td>
<td>$0.805</td>
<td>476.92</td>
</tr>
<tr>
<td>Gas, commercial</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>8,504,842</td>
<td>8,286,646</td>
<td>- 2.57</td>
</tr>
<tr>
<td>Customers</td>
<td>11,502</td>
<td>16,098</td>
<td>39.96</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>795.4</td>
<td>514.8</td>
<td>-32.38</td>
</tr>
<tr>
<td>Real retail price/Mcf</td>
<td>$0.564</td>
<td>$1,455</td>
<td>154.16</td>
</tr>
<tr>
<td>Real wellhead price/Mcf</td>
<td>$0.142</td>
<td>$0.807</td>
<td>468.31</td>
</tr>
<tr>
<td>Gas, industrial</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>22,591,688</td>
<td>12,428,011</td>
<td>- 44.99</td>
</tr>
<tr>
<td>Customers</td>
<td>264</td>
<td>442</td>
<td>61.42</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>85,575</td>
<td>28,115</td>
<td>-66.35</td>
</tr>
<tr>
<td>Real retail price/Mcf</td>
<td>$0.297</td>
<td>$1,233</td>
<td>315.15</td>
</tr>
<tr>
<td>Real wellhead price/Mcf</td>
<td>$0.146</td>
<td>$0.876</td>
<td>500.00</td>
</tr>
<tr>
<td>Gas, other</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>9,337,152</td>
<td>182,348</td>
<td>- 96.05</td>
</tr>
<tr>
<td>Customers</td>
<td>10</td>
<td>9</td>
<td>-10.02</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>933,715</td>
<td>22,794</td>
<td>-91.56</td>
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<tr>
<td>Real retail price/Mcf</td>
<td>$0.267</td>
<td>$1,428</td>
<td>476.14</td>
</tr>
<tr>
<td>Real wellhead price/Mcf</td>
<td>$0.146</td>
<td>$0.876</td>
<td>500.00</td>
</tr>
<tr>
<td>Gas, total</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>53,942,581</td>
<td>33,093,443</td>
<td>- 37.17</td>
</tr>
<tr>
<td>Customers</td>
<td>93,632</td>
<td>129,582</td>
<td>37.71</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>576.1</td>
<td>263.4</td>
<td>-51.80</td>
</tr>
<tr>
<td>Real retail price/Mcf</td>
<td>$0.046</td>
<td>$1.430</td>
<td>210.87</td>
</tr>
<tr>
<td>Real wellhead price/Mcf</td>
<td>$0.144</td>
<td>$0.832</td>
<td>477.70</td>
</tr>
<tr>
<td>Real electric price</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Residential/kwh</td>
<td>$0.0206</td>
<td>$0.0234</td>
<td>13.59</td>
</tr>
<tr>
<td>Commercial/kwh</td>
<td>$0.0239</td>
<td>$0.0248</td>
<td>13.24</td>
</tr>
<tr>
<td>Industrial/kwh</td>
<td>$0.0118</td>
<td>$0.0170</td>
<td>44.07</td>
</tr>
<tr>
<td>Other/kwh</td>
<td>$0.0256</td>
<td>$0.0248</td>
<td>-3.13</td>
</tr>
<tr>
<td>Total/kwh</td>
<td>$0.0185</td>
<td>$0.0216</td>
<td>16.76</td>
</tr>
</tbody>
</table>

### Table 1. Iowa Electric Light and Power Co., 1970 Compared to 1982, Real 1967 Dollars -- continued.

<table>
<thead>
<tr>
<th>Variable</th>
<th>1970</th>
<th>1982</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. 2 heating oil price index</td>
<td>106.5</td>
<td>670.7</td>
<td>529.77</td>
</tr>
<tr>
<td>Energy conservation price proxy</td>
<td>141.5</td>
<td>331.5</td>
<td>134.28</td>
</tr>
<tr>
<td>Consumer Price Index--W</td>
<td>116.3</td>
<td>258.6</td>
<td>124.15</td>
</tr>
<tr>
<td>Real income per capita</td>
<td>$3,206.36</td>
<td>$3,718.98</td>
<td>15.99</td>
</tr>
<tr>
<td>Yearly HDO</td>
<td>6,964</td>
<td>7,111</td>
<td>2.11</td>
</tr>
<tr>
<td>Yearly HDO (1969-1982 average)</td>
<td>6,906</td>
<td>6,906</td>
<td></td>
</tr>
</tbody>
</table>

Retail gas prices, real per capita income, real heating oil prices, real electric prices, real energy conservation measure prices, and weather conditions (HDO) demand--annual per customer usage was estimated for the three major customer classes, residential, commercial, and industrial, as well as for total usage per customer.

To reduce problems of heteroscedasticity with the aggregate data set, estimates were made using separate customer classes. In the case of the commercial, industrial, and total models, dummy variables, taking the value zero or one, indicating the individual utilities were used. These were not used in the reported residential models for two reasons. First, in contrast to the other three classifications, residential annual gas usage tends to be homogeneous across all eight utilities. For example, the mean annual residential customer usage for the individual utilities ranges from 139 Mcf/year to 155 Mcf/year, while the group mean is 147 Mcf/year. Second, the simpler residential model without the utility dummy variables has a lower mean-square error than the one with the dummies, indicating that, although R2, the percentage of explained variance, improves due to the addition of more independent variables, addition of variables simultaneously decreases the precision of the equation in terms of appropriate model specification. In addition, the partial regression coefficients of the residential model including the utility dummies supports the exclusion of the dummies, since only three of the seven coefficients were significant at the .05 level.

An additional dummy variable was used to distinguish between two sets of data years. A variable accounting for the difference between data prior to 1982 and for 1982 was used (1) to capture the shift from real price increases in
<table>
<thead>
<tr>
<th>Variable</th>
<th>1970</th>
<th>1982</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas, residential</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>88,375,773</td>
<td>80,478,606</td>
<td>-9.44%</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>164.6</td>
<td>125.3</td>
<td>-21.86%</td>
</tr>
<tr>
<td>Retail price/Mcf</td>
<td>$0.0829</td>
<td>$0.1619</td>
<td>95.90%</td>
</tr>
<tr>
<td>Wellhead price/Mcf</td>
<td>$0.1435</td>
<td>$0.6686</td>
<td>367.13%</td>
</tr>
<tr>
<td>Gas, commercial</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>52,956,785</td>
<td>51,397,465</td>
<td>-1.02%</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>842.4</td>
<td>675.9</td>
<td>-19.76%</td>
</tr>
<tr>
<td>Retail price/Mcf</td>
<td>$0.5892</td>
<td>$1.4942</td>
<td>151.68%</td>
</tr>
<tr>
<td>Wellhead price/Mcf</td>
<td>$0.1442</td>
<td>$0.6633</td>
<td>366.90%</td>
</tr>
<tr>
<td>Gas, Industrial</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>134,649,607</td>
<td>84,082,425</td>
<td>-37.55%</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>92,925.9</td>
<td>55,536.6</td>
<td>-40.64%</td>
</tr>
<tr>
<td>Retail price/Mcf</td>
<td>$0.3131</td>
<td>$1.2777</td>
<td>307.39%</td>
</tr>
<tr>
<td>Wellhead price/Mcf</td>
<td>$0.1471</td>
<td>$0.6911</td>
<td>370.07%</td>
</tr>
<tr>
<td>Gas, other</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>47,525,729</td>
<td>1,538,220</td>
<td>-96.76%</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>3,168,381.9</td>
<td>109,873.3</td>
<td>-96.53%</td>
</tr>
<tr>
<td>Retail price/Mcf</td>
<td>$0.2425</td>
<td>$1.2977</td>
<td>436.95%</td>
</tr>
<tr>
<td>Wellhead price/Mcf</td>
<td>$0.1414</td>
<td>$0.6514</td>
<td>390.07%</td>
</tr>
<tr>
<td>Gas, total</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sales (Mcf)</td>
<td>323,547,094</td>
<td>217,496,722</td>
<td>-32.78%</td>
</tr>
<tr>
<td>Usage per customer (Mcf)</td>
<td>530.0</td>
<td>302.2</td>
<td>-42.83%</td>
</tr>
<tr>
<td>Retail price/Mcf</td>
<td>$0.4883</td>
<td>$1.4554</td>
<td>190.14%</td>
</tr>
<tr>
<td>Wellhead price/Mcf</td>
<td>$0.1444</td>
<td>$0.6800</td>
<td>372.22%</td>
</tr>
<tr>
<td>No. 2 heating oil price index</td>
<td>106.5</td>
<td>670.7</td>
<td>529.77%</td>
</tr>
<tr>
<td>Consumer Price Index-M</td>
<td>116.3</td>
<td>288.6</td>
<td>148.15%</td>
</tr>
<tr>
<td>Real income per capita</td>
<td>$3,225.28</td>
<td>$3,668.07</td>
<td>11.87%</td>
</tr>
<tr>
<td>Yearly HDD</td>
<td>7.062</td>
<td>7.156</td>
<td>1.33%</td>
</tr>
<tr>
<td>Energy conservation price proxy</td>
<td>141.5</td>
<td>331.5</td>
<td>134.28%</td>
</tr>
</tbody>
</table>

Table 3. Average Prices per Mcf 1980 and 1981, 1967 Real Prices in Parentheses

<table>
<thead>
<tr>
<th></th>
<th>1980</th>
<th>1981</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S. residential</td>
<td>$3.61</td>
<td>4.18</td>
<td>15.79%</td>
</tr>
<tr>
<td></td>
<td>(1.46)</td>
<td>(1.54)</td>
<td>(5.48)</td>
</tr>
<tr>
<td>Iowa residential</td>
<td>3.20</td>
<td>3.92</td>
<td>22.50%</td>
</tr>
<tr>
<td></td>
<td>(1.30)</td>
<td>(1.44)</td>
<td>(10.77)</td>
</tr>
<tr>
<td>U.S. commercial</td>
<td>3.34</td>
<td>3.91</td>
<td>17.07%</td>
</tr>
<tr>
<td></td>
<td>(1.35)</td>
<td>(1.44)</td>
<td>(6.67)</td>
</tr>
<tr>
<td>Iowa commercial</td>
<td>2.85</td>
<td>3.53</td>
<td>23.86%</td>
</tr>
<tr>
<td></td>
<td>(1.15)</td>
<td>(1.30)</td>
<td>(13.04)</td>
</tr>
<tr>
<td>U.S. industrial</td>
<td>2.81</td>
<td>3.22</td>
<td>14.59%</td>
</tr>
<tr>
<td></td>
<td>(1.14)</td>
<td>(1.18)</td>
<td>(3.51)</td>
</tr>
<tr>
<td>Iowa industrial</td>
<td>2.51</td>
<td>3.10</td>
<td>23.51%</td>
</tr>
<tr>
<td></td>
<td>(1.02)</td>
<td>(1.14)</td>
<td>(11.76)</td>
</tr>
<tr>
<td>U.S. all sectors</td>
<td>3.13</td>
<td>3.66</td>
<td>16.93%</td>
</tr>
<tr>
<td></td>
<td>(1.27)</td>
<td>(1.34)</td>
<td>(5.51)</td>
</tr>
<tr>
<td>Iowa all sectors</td>
<td>2.81</td>
<td>3.46</td>
<td>22.78%</td>
</tr>
<tr>
<td></td>
<td>(1.14)</td>
<td>(1.27)</td>
<td>(11.40)</td>
</tr>
<tr>
<td>U.S. average pipeline rates</td>
<td>2.41</td>
<td>2.88</td>
<td>19.50%</td>
</tr>
<tr>
<td></td>
<td>(0.98)</td>
<td>(1.06)</td>
<td>(8.16)</td>
</tr>
<tr>
<td>Iowa average pipeline rates</td>
<td>2.48</td>
<td>2.80</td>
<td>12.90%</td>
</tr>
<tr>
<td></td>
<td>(1.00)</td>
<td>(1.03)</td>
<td>(3.00)</td>
</tr>
</tbody>
</table>


#2 heating oil to a real price decrease in 1982 and (2) to acknowledge the change from general real growth in per capita income through 1981 to a substantial real income drop in 1982. In developing the results, several data year spans were examined and evaluated. The use of 1974-1982 was chosen because the period encompasses the first real public concern about the energy crisis in the mid-1970s and the post-1977 NGPA gas legislation period. Since the data are pooled time series covering eight utilities and nine years, the data set contains 72 observations.
HDD is not included in the model for the industrial class since a large portion of gas use within the class is held to be nonheat sensitive and many firms by rate classification are interruptible. The effect of the substitute good price, the index of #2 heating oil, was not significant in the residential and commercial models. Perhaps the lack of a significant relationship indicates generally minimal dual-fuel capabilities among such users. An alternate measure of the price of a natural gas substitute for residential consumers is an index of the price of conservation measures such as insulation, weatherization, or more efficient technologies. To attempt to determine the influence, the price index for the element of the CPI-W for major housing maintenance and repairs is used as a proxy. This includes supplies and labor costs for plumbing, which would be consistent with installation of solar water heating or a new furnace. It should be a fair approximation of the direct measurement of the real price of many home energy conservation alternatives.

The basic structural specification used in the estimation of natural gas demand was of the Cobb-Douglas form:

\[ Q = A_1 P_{g1} A_2 P_{g2} A_3 P_{g4} A_4 P_{g4} A_5 A_6 Y A_7 P_c A_8 P_c D_1 D_2 D_3 D_4 D_5 D_6 D_7 D_8 U_1. \]

where:
- \( Q \) = annual usage per customer, per class, per utility;
- \( P_{g1} \) = real average retail gas price;
- \( P_{g2} \) = real per capita personal income;
- \( P_{g4} \) = real price index #2 heating oil;
- HDD = yearly heating degree days;
- \( P_c \) = price of conservation measures;
- \( D_1 \) = dummy variables reflecting the j (1 through 8) utilities;
- \( A_1 \) = intercept/multiplicative constant;
- \( A_2 \) = price elasticity for gas;
- \( A_3 \) = income elasticity;
- \( A_4 \) = price elasticity for #2 heating oil;
- \( A_5 \) = HDD elasticity;
- \( A_6 \) = price elasticity of conservation measures;
- \( A_7 \) = coefficient on the jth dummy variable (\( A_7 = 1, J = 8 \))
-\( A_8 \) = INT; \( A_8 = P_{g4} A_9 = I_{ATT} \); \( A_{10} = P_{g4} A_{11} = I_{SUB}; A_{12} = NCENT; I_1 \) is the basic model);
- \( D_2 \) = dummy variable reflecting year;
- \( A_9 \) = coefficient on the year dummy; and
- \( U_1 \) = stochastic error term.

The results of the least-squares regression analysis using logarithmic transformations of the above model are reported in Table 4. Several points are worthy of discussion. First, since the estimations were made using log-linear forms, the coefficients on the price, income, and HDD terms can be interpreted as elasticities. That is, for example, given \( A_2 = -0.88 \), as a 10 percent increase in real retail gas price occurs, the quantity of gas demanded by residential customers would be expected to fall by 8.88 percent on an annual basis, all else being equal. Second, and perhaps more important, in comparison with results based on 1974-1981 data, the price coefficients (own-price elasticities), increased in absolute value for all customer classes with the inclusion of 1982 data. As an example, in the residential model the own-price elasticity increased by 10 percent. Similarly, for the models including an estimate of the income elasticity, the income coefficients (\( A_8 \)) increased. These may indicate that, over time, the demand for natural gas with respect to own-price (natural gas price) and income changes has become relatively more elastic. Therefore, customer usage of gas has become more responsive to changes in gas price and income.

The third notable point is that the coefficient \( A_6 \), the cross-price elasticity on the residential conservation measure is positive, significant at the .01 level, and has the added effect of improving both \( R^2 \) and the partial coefficients on the other variables in the equation. Due to the high interrelationship of the real price of natural gas and the real price of conservation measures, the estimate of the relationship was made, and the residuals were used in the demand model in lieu of the conservation price index. The \( A_6 \) coefficient of .41 means that conservation is a substitute for natural gas, and the demand for gas will fall if the real price of conservation falls. Because of the use of the residuals, the effect of gas price interrelating to conservation price has been controlled, and the \( A_6 \) coefficient is a "pure" price effect showing substitution net of the effect on the budget constraint due to prices changing.
### Table 4. Variable Coefficients, Retail Price Model Regressions, 1974-1982

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A_1$</td>
<td>-2.697</td>
<td>-2.701</td>
<td>8.505</td>
<td>.641</td>
</tr>
<tr>
<td></td>
<td>(.039)</td>
<td>(.168)</td>
<td>(.001)</td>
<td>(.044)</td>
</tr>
<tr>
<td>$A_2$</td>
<td>-.488</td>
<td>-.375</td>
<td>-.655</td>
<td>-.677</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.001)</td>
<td>(.001)</td>
<td>(.001)</td>
</tr>
<tr>
<td>$A_3$</td>
<td>.676</td>
<td>.457</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.128)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_4$</td>
<td></td>
<td></td>
<td>.310</td>
<td>.179</td>
</tr>
<tr>
<td></td>
<td>(.022)</td>
<td>(.139)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_5$</td>
<td>.240</td>
<td>.594</td>
<td></td>
<td>.612</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.053)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_6$</td>
<td>.056</td>
<td>.293</td>
<td></td>
<td>.022</td>
</tr>
<tr>
<td></td>
<td>(.104)</td>
<td>(.754)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_7$</td>
<td>.220</td>
<td>1.998</td>
<td></td>
<td>.533</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.001)</td>
<td></td>
<td>(.001)</td>
</tr>
<tr>
<td>$A_8$</td>
<td>.237</td>
<td>.372</td>
<td></td>
<td>.077</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.247)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_9$</td>
<td>.440</td>
<td>1.354</td>
<td></td>
<td>.081</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.232)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_{10}$</td>
<td>.518</td>
<td>.752</td>
<td></td>
<td>.122</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.084)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$A_{11}$</td>
<td>.310</td>
<td>-.168</td>
<td>-.068</td>
<td>.137</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.412)</td>
<td>(.001)</td>
<td>(.034)</td>
</tr>
<tr>
<td>$A_{12}$</td>
<td>.821</td>
<td>4.327</td>
<td>1.430</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.001)</td>
<td>(.001)</td>
<td></td>
</tr>
<tr>
<td>$A_y$</td>
<td>.086</td>
<td>.078</td>
<td>-.166</td>
<td>.137</td>
</tr>
<tr>
<td></td>
<td>(.004)</td>
<td>(.053)</td>
<td>(.050)</td>
<td>(.034)</td>
</tr>
<tr>
<td>$A_C$</td>
<td>.408</td>
<td>.954</td>
<td>.983</td>
<td>.948</td>
</tr>
<tr>
<td></td>
<td>(.001)</td>
<td>(.001)</td>
<td>(.001)</td>
<td>(.001)</td>
</tr>
</tbody>
</table>

Note: Figures in parentheses are significance levels.

---

**Gas Price Elasticities**

**Relationship of Real Retail and Wellhead Prices**

To estimate the expected effect of changes in real wellhead prices on annual per customer natural gas usage in Iowa, it is necessary and useful to establish the association between real retail and real wellhead prices. A relationship is logically expected in that retail prices, in at least some part, reflect the prices paid for gas at the wellhead, particularly since pipelines’ PPA mechanisms allow pass-through of purchased gas costs.

Figure 1 presents historic data by class. It shows that as real wellhead prices increased, real retail prices also increased, but at a less than proportionate rate. The plots of the data indicate that the relationship of retail and wellhead prices is nonlinear. Thus, the exponential form, $\text{Real Retail Price} = C_y \cdot \text{Real Wellhead Price}^{C_x}$, was used to estimate the empirical relationship. The logarithmic transformation, $\ln(\text{Real Retail Price}) = \ln(C_y) + C_x \cdot \ln(\text{Real Wellhead Price}) + u$, was made to estimate the coefficients using least-squares linear regression methods. The results based on the pooled time series data for 1969-1982 for the eight major gas utilities are in Table 5.

![Figure I. Plot of Real Retail Gas Prices versus Real Wellhead Gas Prices](image)

The $C_y$ coefficient, that is, the exponent on real wellhead prices, indicates, for example, in the case of residential
Table 5. Relationship of Real Retail and Real Wellhead Prices

<table>
<thead>
<tr>
<th>Classification</th>
<th>Model</th>
<th>( R^2 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>Real Retail Price = 1.567 ( {\text{Real WH Price}} {0.333} )</td>
<td>.88</td>
</tr>
<tr>
<td></td>
<td>Commercial</td>
<td>Real Retail Price = 1.325 ( {\text{Real WH Price}} {0.405} )</td>
</tr>
<tr>
<td></td>
<td>Industrial</td>
<td>Real Retail Price = 1.479 ( {\text{Real WH Price}} {0.765} )</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>Real Retail Price = 1.527 ( {\text{Real WH Price}} {0.573} )</td>
</tr>
</tbody>
</table>

Note: All coefficients significant at the .01 level.

gas prices, that for each one percent change in real wellhead price, a .333 percent increase in residential real retail price occurs. No significant differences among the utilities or over the estimates based on 1969-1981 data were observed, except that the fit of the equations improves slightly with the addition of the 1982 data. Since the estimates are based on data from 1969-1982, caution should be used in projecting these price relationships considerably beyond that range of experience.

In summary, there is evidence that since 1969 the proportion of real retail prices represented by real wellhead prices has grown significantly. The exponential relationship is apparent in an examination of the plot of the data and can be statistically supported and readily estimated through the use of simple log-linear models.

Customer Usage Response to Changes in Wellhead Prices

As stated above, establishing the connection between real wellhead and real retail prices is both necessary and useful. Such a relationship provides the theoretical bridge to move from the estimation of retail gas demand based on real retail gas prices to the estimation of retail gas demand based on wholesale supply or \'cost\' prices. That is, if retail usage is a function of real retail prices, and if real retail prices are a function of real wellhead prices, then retail usage must also be a function of real wellhead prices. The relationship is useful because it affords two estimates, one indirect and one direct, of the demand response to changes in wellhead prices.

The estimation of usage response can be made indirectly, derived from the direct estimation of gas usage as a function of real wellhead price. Let:

\[ R = b_1 h + b_2 \text{ and } \mathbf{q} = \mathbf{a} h + b_3, \]

where:

- \( R \) = real retail price;
- \( h \) = real wellhead price;
- \( \mathbf{q} \) = quantity demanded;
- \( b_1 \) = factor reflecting other variables; and
- \( b_3 \) = coefficients on respective terms.

By substitution for \( \mathbf{q} \), then:

\[ \mathbf{q} = b_1 \mathbf{h}^2 + b_2 \mathbf{h} + b_3; \]

Let:

\[ \mathbf{b}_1 = b_1 \mathbf{h}^2 \text{ and } \mathbf{b}_2 = b_2 \mathbf{h} \text{; } \]

then:

\[ \mathbf{q} = \mathbf{b}_1 \mathbf{h}^2 + \mathbf{b}_2 \mathbf{h} + b_3. \]

The wellhead price elasticity is then \( \mathbf{b}_2 \), which is equal to \( b_2 \) times \( \mathbf{h} \). Estimates of \( \mathbf{b}_2 \) and \( b_3 \) are available from the models described above, where they were referred to as \( b_2 \) and \( b_3 \), respectively. The indirect estimates of \( b_2 \), the wellhead elasticities, are shown in Table 6. The wellhead price elasticities are estimated to range from -0.16 to -0.50 depending upon customer class. Given the results of this indirect estimation technique, it is expected that the values of the wellhead price elasticities estimated directly would be of similar magnitude.

The direct estimation model closely parallels the model used to estimate the price response due to real retail price changes and is also of the Cobb-Douglas form. The basic model used was:

\[ R = b_1 p + b_2 h + b_3; \]

\[ \mathbf{Y} = \mathbf{a} p + b_1 h + b_2 h + b_3. \]
Table 6. Indirect Estimates of Wellhead Elasticities

<table>
<thead>
<tr>
<th>Model</th>
<th>$\eta_1$A2</th>
<th>$\eta_2$C2</th>
<th>$\nu_1$A4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential*</td>
<td>-0.468</td>
<td>0.333</td>
<td>-1.156</td>
</tr>
<tr>
<td>Commercial</td>
<td>-0.375</td>
<td>0.485</td>
<td>-1.182</td>
</tr>
<tr>
<td>Industrial</td>
<td>-0.655</td>
<td>0.765</td>
<td>-1.501</td>
</tr>
<tr>
<td>Total</td>
<td>-0.667</td>
<td>0.573</td>
<td>-1.382</td>
</tr>
</tbody>
</table>

*Model without conservation price proxy.

where the variables are as previously defined, except $P_{NH}$ equals the real wellhead price.

The results of the least-squares regressions using log-linear forms of the models are presented in Table 7. Comparison of the indirectly estimated $\eta_2$ values in Table 6 with the direct estimates contained in Table 7 shows that the estimates are generally of similar size for all models.

As is the case with $\eta_2$, $\nu_1$ is an elasticity and should be interpreted, for example, given $\eta_2 = -1.7$, that as the real wellhead price increases by one percent, residential natural gas consumption would be expected to fall by approximately 1.7 percent. Consistent with economic theory, the sign on the cross-price elasticity ($\nu_1$) is positive; thus, as the price of #2 heating oil increases by 10 percent, the consumption of natural gas by industrial customers rises by nearly 4 percent. Conversely, if the price of oil dropped by 10 percent, gas consumption would be expected to fall by nearly 4 percent as industrial users substitute relatively less expensive oil for gas.

Summary and Policy Implications

The findings provide strong empirical evidence in support of the economic theory that consumer are responsive to changes in prices, income, and related factors. In fact, Iowa data show a significant customer response by each class to changes in the real retail price of natural gas. Estimates of the size of the response range from a decrease of 3.75 percent to 6.67 percent for every 10 percent increase in real price depending upon customer group. There is some evidence that the own-price responsiveness increases over time. Similarly, the responsiveness to income changes appears to increase from 1981 to 1982, from a 4.8 percent to a 8.72 percent residential response, and from a 3.6 percent to a 4.57 percent commercial response, for a 10 percent income change.

Table 7. Variable Coefficients, Wellhead Price Model Regressions, 1976-1982

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\beta_1$</td>
<td>-2.926</td>
<td>-1.469</td>
<td>7.677</td>
<td>2.211</td>
</tr>
<tr>
<td></td>
<td>(.059)</td>
<td>(.448)</td>
<td>(.001)</td>
<td>(.563)</td>
</tr>
<tr>
<td>$\beta_2$</td>
<td>-1.168</td>
<td>-1.178</td>
<td>-0.518</td>
<td>-0.301</td>
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<td>(.001)</td>
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<tr>
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<td>(.001)</td>
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</table>

Note: Figures in parentheses are significance levels.
The retail demand response to changes in wellhead prices is smaller than the response related to retail price, but it is nonetheless important. The demand response estimates range from just under 3 percent to just over 5 percent for each 10 percent change in wellhead price. The pass-through of the PGA may be the major link between demand for retail gas and wellhead prices.

While fuel oil (No. 2 heating oil) price effects were estimated for all customer classes, the only significant cross-price elasticities were found in the industrial market, using either the real or wellhead gas price models. The estimated consumption response is an approximate 3 percent to 4 percent increase in gas demand when real oil price increases by 10 percent, or a 3 percent to 4 percent decrease in gas demand when real oil price falls by 10 percent, demonstrating that oil is a substitute for gas in this sector of the market.

Interesting results were gained from the inclusion of a measure of the real price of residential energy conservation measures. The sizable positive coefficient shows that energy conservation is a viable substitute for natural gas use. As policy makers, we should realize that while some conservation is an adjustment of standards such as setting back the thermostat, the conservation accounted for in this study is less transient and requires labor and capital investments. Once the trade-off of natural gas to such conservation has occurred, there seems to be little likelihood of a resumption of past gas consumption levels.

The significance of the sign and magnitude of the price and income elasticity estimates is as follows: (1) As real and wellhead prices rise, quantity demanded falls, but by a smaller percentage. (2) As income falls, demand for gas falls, or as income rises, demand rises, but the percentage change in demand is less than the percentage change in income. (3) Residential demand falls as real conservation services and supply prices go down. (4) Industrial demand for gas falls as fuel oil prices fall, but by a smaller percentage.

Due to the absolute value of the natural gas price elasticities being less than one, demand is said to be inelastic. The inelasticity is a consequent factor because it means that as natural gas prices increase, utility revenues will grow even though sales decline, until else being equal. It is also of consequence to the fact that the price and income elasticities are generally increasing in absolute value over time; this indicates that customers are becoming more responsive to price and income changes. Since utilities are still motivated to increase price to maximize revenues, the importance of close regulatory examination of natural gas price increases at both the wellhead and retail level in a monopoly industry is clear.

The study results also give early warnings that customers of all types, small and large, heating and nonheating, residen-

tial and industrial, are reacting to increases in gas prices at an apparently increasing rate. Realistic, acceptable substitutes beyond dual-fuel capacity still exist for small as well as large customers. People's tastes can change permanently such that any proposed reallocation of costs among or to different customer groups must be examined for both short- and long-range effects, that is, will there still be customers to serve? Perhaps rather than how to allocate the recovery of all costs and a fair rate of return, the question should be why did we overbuild? Overcontract? Who is responsible? The ratepayer? The stockholders? The managers? The commissioners? How should we share the burden?
ARE INTERFUEL AND INTERCOMPANY RIVALRY EFFECTIVE SURROGATES FOR COMPETITION AND REGULATION IN THE INTERSTATE NATURAL GAS PIPELINE INDUSTRY?

Julian M. Greene

1. Introduction

It is well known that during the past two years, "market forces" have significantly affected the behavior of interstate natural gas pipelines in the United States. Exercising "market-out" clauses with producers; requesting regulatory approval of rate designs that could help retain industrial gas users that have the capability to use alternate fuels; and implementing special sales programs (also intended to save loads vulnerable to other fuel sources) are some manifestations of pipelines' attempts to cope with the changed environment that now confronts them.

In general, as will be seen, these various actions should not be classified as competition in the technical economics sense. Rather, they are rivalry, and the purpose of this paper is to distinguish between the two concepts and examine the extent to which the rivalry that is occurring affects the gas pipeline industry in the same way that textbook

Note: Any implied or expressed opinions are the author's and do not necessarily represent Tranaco positions. Appreciation is expressed to Louis Rice, Ellen Malizia, and Doug Kirk of Tranaco for research assistance and table/figure preparations.

"Pure" competition would.

The analysis defines key terminology in Section II, takes a brief look at current operational characteristics of the gas industry in Section III, and uses Section IV to delineate the conceptual benefits of textbook competition. Section V contains the analytic crux of the paper, as rivalry in today's regulated world and rivalry under three hypothetical and successively broader definitions of deregulation are examined to see which of competition's benefits are, or likely would be, realized under each of the four scenarios. Finally, Section VI gives summary conclusions.

II. SOME WORKING DEFINITIONS

It is critical to define key terms used in the analysis that follows. Thus, the important operational aspects of competition, workable competition, rivalry, and (economic) regulation can be delineated.

A. Textbook "Pure" Competition prevails when no one seller (firm) can have appreciable influence on the price of an item being sold, by varying the quantity of output that he himself sells. That is, the market participants are price takers; they consider price to be a parameter. Price is set by market forces and is not subject to any seller's conscious control. With price being market-determined, therefore, only an output decision is made by a firm under pure competition, and there are imperceptible interfirm influences. (This key characteristic is generally associated with there being a homogeneous product that is sold by a large enough number of market participants so that no firm's share is very large.)

B. Workable Competition describes a "real-world" environment where the stricter conditions of pure competition are not present, but, in a practical sense, there are forces adequate enough to constitute "effective" competition. These include, for example, a large number of participants, free entry and exit, no "protection" for inefficient participants, and a willingness to adopt new technologies.

C. Rivalry, in contrast, characterizes situations in which sellers or firms strive for potentially incompatible positions, and (an important point) they are aware of this incompatibility. Thus, rivals make not only output decisions, but they also make price decisions, and they definitely have perceptible influences on each other. Stated simply, one rival's gains are usually another's losses. In technical economics terms, rivalry can be an aspect of "imperfect competition."

D. Economic Regulation refers to activities by public authorities (such as regulatory agencies) that are intended to protect consumers from monopoly power pricing. In the natural gas industry, regulation encompasses certain wellhead
price controls facing producers. It also touches interstate gas transmission companies and gas distribution companies because they are subject to Federal Energy Regulatory Commission (FERC) and state or local jurisdiction, respectively, over entry and exit, accounting methods, service standards, financial structures, and rates (through rate-of-return allowed on investment, as designated in the firms’ ratebase.)

III. Current Operational Characteristics of the U.S. Gas Industry

It is instructive to examine briefly some of the main operating traits of the gas industry because these relate to the central focus of this paper and because, in part, these features suggest which of Section II’s definitions apply. Market structures of the industry segments will be reviewed, followed by observations about the specific situations that are occurring at the interstate pipeline company level.

A. Market Structures of Industry Segments

In general, both the “input” and “output” ends of the gas production stage are probably workably competitive. As regards the former, the number of oil and gas field services suppliers is seemingly adequate to be considered competitive. Table, the most recent (1977) Census of Manufactures reported 9,162 total establishments in Industry Group 138 during 1977, with 1,938 of those meeting the Census criterion of moderate size (at least 20 employees). An additional piece of heuristic evidence about survival in this facet of the gas industry, even though limited in scope, is that during 1982 and 1983, equipment and services activities together accounted for 72 percent (of 124 total) and 58 percent (of 131 total), respectively, of the oil and gas industry bankruptcies in the Houston, Texas area. Viewing producers as sellers, more analytic evidence is available. At an aggregate level, two Federal Trade Commission (FTC) studies (using 1970 and 1975 data) found relatively low concentration ratios. More recently, the October 17, 1983, issue of the Oil & Gas Journal ("OGJ Report - The OGJ 400," p. 75) published 1982 data from which production and reserves concentration ratios (CRs) can be calculated, as shown in Table 1. When these results are measured against the 1982 U.S. Department of Justice merger guidelines of low and medium concentration corresponding to four-firm CR’s under 50 and between 50 and 70, respectively, aggregate gas production is very uncompetitive. In addition, again limited information on lack of “protection” for inefficient producers shows that Houston area exploration and production bankruptcies virtually doubled between 1982 and 1983, from 23 to 45.

For interstate gas pipelines, David Head’s calculations of 1979 CR’s found moderate concentration in states where pipelines purchase most of their gas, while higher concentration prevailed in the states where most interstate sales for resale occur. Thus, workable competition is suggested for most of transmission companies’ receiving capacity, but imperfect competition is suggested for most of resale delivery capacity. (Direct industrial sales by interstate pipelines are not regulated by the FERC and appear to be workably competitive, particularly where there is price competition from alternate fuels.) Given the certification requirements that face pipelines, Head’s delivery capacity results would seem to agree with intuitive expectations and probably would persist even if one defined market areas more precisely than using entire states.

Thus, gas distribution companies purchase gas under generally imperfectly competitive ("oligopoly") conditions, but, by franchise definition, they sell gas as local monopolies. However, to the extent that their burner-tip customers can use alternate fuels, gas distributors may not be "effec-

## Table 1. U.S. Natural Gas Producers 1982 Concentration Ratios

| Companies | Tcf % | Top 1 | Tcf % | Top 5 | Tcf % | Top 10 | Tcf % | Top 20 | Tcf % | Top 400 | Tcf % | Total U.S. | Tcf % |
|-----------|-------|-------|-------|-------|-------|--------|-------|-------|-------|-------|--------|-------|--------|-------|
| Top 1     | 1     | 6     | 16    | 8     |       |        |       |       |       |       |        |       |        |       |
| Top 5     | 4     | 22    | 54    | 27    |       |        |       |       |       |       |        |       |        |       |
| Top 10    | 6     | 33    | 80    | 40    |       |        |       |       |       |       |        |       |        |       |
| Top 20    | 8     | 44    | 105   | 52    |       |        |       |       |       |       |        |       |        |       |
| Top 400   | 11    | 61    | 137   | 68    |       |        |       |       |       |       |        |       |        |       |
| Total U.S.| 18    | 100   | 202   | 100   |       |        |       |       |       |       |        |       |        |       |

Source: Calculated from Oil and Gas Journal, October 17, 1983.
is attenuated by the active presence of substitute energy sources.

B. Rivalries among Interstate Pipelines

Having indicated an imperfectly competitive market structure between pipelines and distributors, the second operational characteristic, namely, the current actions by pipelines, establishes that the behavior occurring within the market structure is indeed rivalry. Furthermore, these actions are happening at two levels: pipeline versus pipeline, and gas versus other fuels. The former (interpipeline rivalry), of course, affects pipelines directly, while the latter (interfuel rivalry) affects pipelines indirectly in the case of direct end-user sales, but must be "passed back" by a distributor from the burnertip to a pipeline in the case of sales for resale.

Simply put, the actions referred to are price-setting activities. To a very great extent (almost totally), at the citygate link between pipelines and distributors, these are driven by gas acquisition costs that are rising and differ across pipelines (the "cushion" issue) since these are the major component of citygate and burnertip prices. These rising and differential costs, recession economic conditions, and falling prices of alternate fuels have been strong incentives for pipelines to act. Table 2 provides information to suggest that, although gas costs are a major factor now, this has not always been so. Thus, between 1970 and 1982, average wellhead gas cost increased fourteenfold and doubled the fraction of average retail (burnertip) gas price for which it accounts. With only a 27 percent "share" in 1970, changes in gas costs then could not have been expected to exert the same influence that 1982's 55 percent "share" did. An important conclusion to draw from this is the simple fact that today there are definite limits on the extent to which pipelines can affect citygate prices through transmission charge adjustments. Acquisition costs of gas are the much more significant force.

Causes of this observed gas cost increase have been the price escalations permitted and prescribed by the 1978 Natural Gas Policy Act (NGPA) and the seller's market circumstances that existed after passage of the NGPA when pipelines struggled to alleviate gas supply deficits and their attendant service curtailments. When these gas cost increases are combined with perhaps even small effects on transmission charges caused by "take-or-pay" obligations, the resulting citygate price can be higher than market forces would dictate. Before elaborating on this conclusion, brief comment on take-or-pay pressures is warranted.

It is common knowledge that there is presently a surplus of available gas ("deliverability") in the United States, due simply to the fact that all the gas that producers would like to deliver cannot, in turn, be sold by pipelines and distributors. To a great extent, deliverability is a discretionary variable for producers, as decisions to make more or less gas available are prompted by geophysical concerns (reservoir drainage) and economic motives (need for current cash flows). Whatever the reasons, however, deliverability plays a pivotal role in many of today's gas contracts, since "take-or-pay" clauses require gas buyers to pay for minimum volumes, expressed as percentages of deliverability, even if the gas is not taken. (Buyers expect that this prepaid gas can and will be taken at a future time.) Therefore, if market demand for gas is depressed (so that sales are reduced), but producer deliverability is high, then take-or-pay obligations will rise. Table 3 illustrates the excess deliverability problem for Transco's system. Accordingly, during 1978-1979, as Transco emerged from its supply-constrained curtailment status, annual production (volumes actually taken from producers) and deliverability coincided. Excess deliverability occurred in 1980, and it quickly worsened to the point where the rendered volumes of over 1.2 Tcf per year actually exceeded Transco's pipeline capacity even if there had been markets for such volumes. When a pipeline finances take-or-pay payments, the finance carrying charges are included in its FERC-regulated rates, thereby increasing the pipeline's cost-of-service revenue.

<table>
<thead>
<tr>
<th>Table 2, U.S. Average Natural Gas Price Components</th>
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<tr>
<td>1970</td>
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<td>Transmission</td>
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<tr>
<td>Citygate</td>
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<tr>
<td>Distribution</td>
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<td>Retail</td>
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Source: American Gas Association, 1982 Gas Facts (Table 9-5).
Table 3. History of Transco's Reserves, Production, and Deliverability, 1971-1983

<table>
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<tr>
<th>Year</th>
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<th>Deliverability (Bcf)</th>
<th>Year-end Reserves (Bcf)</th>
<th>Production (Bcf)</th>
<th>Deliverability (Bcf)</th>
<th>Deliverability (Bcf)</th>
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<td>593</td>
<td>6,495</td>
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<td>6,495</td>
<td>7.2</td>
<td>6.651</td>
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<tr>
<td>1981</td>
<td>990</td>
<td>990</td>
<td>6,495</td>
<td>7.2</td>
<td>6.651</td>
<td>6.7</td>
</tr>
<tr>
<td>1982</td>
<td>1,359</td>
<td>1,359</td>
<td>6,495</td>
<td>7.2</td>
<td>6.651</td>
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<td>1983</td>
<td>1,400</td>
<td>1,400</td>
<td>6,495</td>
<td>7.2</td>
<td>6.651</td>
<td>6.7</td>
</tr>
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</table>

Note: 1979-1983 increases = reserves 7 percent, production 50 percent, and deliverability 136 percent. Includes most available oil from high and off-shore areas.

As indicated, the effects of high citygate prices are reduced marketability for gas against other fuels and other pipelines. Events over the past two years have shown this very clearly. Again citing Transco as an example, Figure 1 portrays some prices relevant to industrial loads during 1982 and 1983. Transco's commodity rate "Transco C" is a wholesale rate and is the component of citygate price that distributors incorporate in their industrial rates. One must therefore implicitly add a distributor's margin to these rates in order to gauge how "competitive" Transco was against high-sulfur (2.9 percent) residual fuel oil. In March 1982, Transco's commodity rate was only about 20¢/million Btu's less than the price of high-sulfur oil. Consequently, any distributor with customers that could burn this fuel oil would have lost such gas loads to oil unless the distributor's margin was less than 20¢ (a highly unlikely situation). Indeed, Transco's customers did experience some load loss at that time. Similar pressures were present during the winter months of 1982-1983. In the same way, with Texas Eastern Gas Transmission Corporation's (TEGOCO) rates at levels lower than both Transco's regular rate and the Industrial Sales Program ("ISP") rate during portions of 1983, interpipeline pressure also became very pronounced.

Figure 1. Transco's Gas Commodity Rates versus Prices of Residual Fuel Oil and Other Gas

*ISP not operable during November and December because firm oil prices precluded qualifying volumes.
Rivalry

Economic power. Impersonal market demand and supply forces solve resource allocation and income distribution problems rather than there being powers in private or government hands. Second, there is freedom of opportunity to participate in activities of one's own choosing. A further aspect of this freedom is that one relies on his own skills and capital to pursue his endeavors.

The three economic efficiency arguments are more analytic.\textsuperscript{18} A. "Normal" profits are earned—when production occurs where price = average total cost (\(p = ATC\)), investors earn their opportunity costs, that is, a return just adequate to maintain their investment in a particular activity (and thus enable production to continue). Precluding a "surplus" return to capital is considered to be a desirable aspect of equitable income distribution for society.

B. There is efficient resource allocation—this results when price = marginal cost (\(p = MC\)) because then society has reached the point at which the value it attaches to an output just equals society's cost of producing the output. For higher output levels, the increment to cost exceeds the benefit gain, while lower output levels result in declines in benefit that exceed the cost reductions.

C. Production is at its most efficient level—production that takes place at the point of overall minimum average cost (0 Min ATC) maximizes productive efficiency.\textsuperscript{19} Competition achieves this because the "price-taker" firms adjust their costs (or else are forced to leave the industry) so that their common minimum average cost level equals the price that has been set by industry supply and demand forces. Since economic theory then shows that (1) each firm's marginal cost \((p)\) also equals average cost at the "Min ATC" level, and (2) each firm's profit-maximizing output is where price \((p)\) equals marginal cost, the optimum output level satisfies a three-part equation: \(p = MC\) = Min ATC. Thus, only the fact that production occurs at the level corresponding to "Min ATC" is needed to assure maximum productive efficiency. But under competition, the forces causing that result must operate through consideration of price.

These benefits of competition are summarized in Table 4 by the "yes" designations in the middle column. It is critically important, however, to understand that the efficient resource allocation and efficient production benefits are, practically speaking, virtually impossible to achieve in any situation where operation occurs subject to the existence of economies of scale. In general, interstate gas pipelines exhibit this scale economies ("natural monopoly") characteristic,\textsuperscript{20} so these two competition benefits are marked \(\ast\) in Table 4 as being essentially moot for the analyses that follow. These practical impossibilities arise from the familiar fact that scale economies manifest themselves in

Figure 2. Rough Estimates of Transco's Actual and Forfeited Sales, May-August 1983

Figure 2 depicts very rough estimates of the effects on Transco of these interfuel and interpipeline influences during summer 1983 when certain loads were most vulnerable. The 2,700 million cubic feet/day (MMCFD) level shown at the top represents Transco's contract obligations, while the bottom curve shows actual sales. Thus, the difference between these two levels estimates the load loss that occurred (measured against contractual sales limits), and the three labels, "bands" indicate what portions were lost to residual fuel oil and other pipelines as well as net losses of power generation load. The varying widths of the "residual fuel oil" and "other pipelines" bands depict impacts of Transco's special sales programs. Thus, for example, early in July, estimated losses to other pipelines were around 670 MMCFD, but by the end of August, this value had been reduced to about 300 MMCFD, primarily due to the success of Transco's CCP (Contract Carriage Program).

In brief, the observed actions by interstate gas pipelines such as Transco (for example, special sales programs, take-or-pay settlements, market-outs, new rate designs, contract renegotiations, and altered gas purchase contract terms) have affected lower delivered prices, have been interdependent with actions by others, and have resulted in gains and losses. This defines rivalry.

IV. Conceptual Benefits of Competition and Regulation

Generally speaking, it is possible to identify five benefits of textbook competition, namely, two qualitative political arguments and three relatively analytic economic efficiency arguments.\textsuperscript{17} Beginning with the former, one first observes that under pure competition there is decentralized

Julian M. Greene
average cost functions (ATC) that decline as output increases and that are situated above their corresponding marginal cost functions (MC). If ATC is less equalled to marginal cost (efficient resource allocation), then average cost is certain to exceed price (average revenue), thereby assuring repeated financial losses and eventual bankruptcy. The inability to achieve efficient production follows simply from the observation that if average costs decline continuously over the relevant range of production, then it is impossible to reach the production level that corresponds to overall "Min ATC." Therefore, stated succinctly, for the arguments that are developed in Section V, attention will be focused on only the first three benefits listed in Table 4.

The third column in Table 4 shows that public utility regulation of interstate gas pipelines brings only one of the three plausible benefits of competition. That is, under rate-of-return-on-investment regulation, the regulatory intent is to affect prices that just cover average costs, thereby precluding "surplus" returns to capital. With the primary purposes of utility regulation being to protect purchasers from exploitative monopoly prices and to capture scale economies so that inefficient facility duplication can be avoided and unit costs can be lower than they would be otherwise, however, the feasible benefits other than normal profits are not realized. Thus, regulation replaces the "impersonal

Interaction of demand and supply and restricts freedom of opportunity (for example, a certificate of public convenience and necessity must be obtained prior to entering the pipeline industry, and abandonment of any service must also have regulatory approval). A major conclusion to draw from Table 4, therefore, is that competition and regulation do not afford the same benefits. Rather, the former offers more than does the latter, so that it is not possible for some alternative structure or behavior to replicate both simultaneously.

V. What Can (Does) Rivalry at the Pipeline Segment Do to Accomplish What Competition or Regulation Would (Does)?

With Table 4's list of the "benchmark" features of textbook competition and regulation, it is now possible to examine whether/how today's rivalry at the pipeline level is (or could be) a surrogate for competition or regulation. Four cases under which rivalry is hypothesized are examined: the status quo of regulation at the three main segments of the industry; the situation of wellhead price deregulation; the case of both wellhead prices and pipeline operations being deregulated; and the scenario of deregulated wellhead prices, pipelines, and distributors.

A. Rivalry within the Status Quo Totally Regulated Structure (that is, Producers, Pipelines, and Distributors Are Regulated)

Considering the competition benefits in order, the regulatory structure of the status quo does not permit the full manifestation of impersonal market forces, and it precludes participation freedom. That is, under regulation, the latter trait is unaffected by rivalry (for example, certification requirements continue). But the former characteristic may be affected somewhat, if a "victim" pipeline is able to mount its own rival reaction to (apparent) market forces by effecting some price changes within the regulatory framework.

Evaluation of the economic efficiency benefit(s) is best accomplished with an analytic representation of the critical economies of scale ("natural monopoly") pipeline characteristic. Figure 3 does this by depicting a sales volume range (ag to g) in the bottom (transmission) panel. Note that the portion of the average total cost function, ATC, that slopes downward to the right. The OPP panel of Figure 3 shows the citygate link between pipeline and distributor where the existing FERC-approved tariff is comprised of the pipeline's gas cost (not shown) and transmission charge $f$ (from the bottom panel). It is seen that a decline in the price of a rival fuel or pipeline causes gas demand facing the pipeline to fall (depicted as a leftward shift of the demand function from $D_1$ to $D_2$), and
production benefits are most,23 the third column ("Rivalry, Total Regulation") in Table 5 summarizes the conclusions for this status quo case. The five "No" entries mean that the rivalry interstate gas pipelines are experiencing today should not necessarily be expected to bring any of the benefits of textbook competition (although the top row’s "No" reflects the possibility of some market force sensitivity). To the contrary, this rivalry is potentially destructive. It is therefore not an effective surrogate for competition. On the other hand, with agreement on four of the five arguments, the status quo seems to be a close substitute for traditional regulation.

B. Rivalry with Wellhead Price Deregulation

[But Continued Pipeline and Distributor Regulation]

The rightmost column in Table 5 gives the results of rivalry in a hypothetical world of no wellhead price regulation. Because pipeline regulation is maintained, however, rivalry has the same effect on the two political arguments that rivalry under total regulation and no rivalry under total regulation have.

The normal profits benefit is affected differently than in the preceding case, however. Specifically, wellhead deregulation introduces "uniform" field prices (eliminating cushions), the flexibility to adjust to changes in market forces, and the greater chance that a pipeline can achieve reduced gas costs, all of which increase the likelihood of preventing sales declines (that is, a citygate price even lower than p' can be effected so that sales volume is maintained). Consequently, costs incurred could equal regulated revenue, and no excess profits would be earned. (The "Yes." simply suggests that this result may not be achieved totally.)

This case is therefore one benefit closer to emulating competition than is the status quo. Observe, though, that it is virtually identical to a totally regulated world that has no rivalry (second column in Table 5). Accordingly, it appears that if regulation of wellhead gas prices were eliminated, and rivalry affecting pipelines persisted, the result would be a situation essentially identical to today's regulated environment but without today's rivalry.

For ease of reference, Table 6 presents the conclusions for all four cases of rivalry being examined. The second ("Total regulation") and third ("Wellhead deregulation") columns are therefore repeated from Table 5, while the last two columns show the results of successively broadening the scope of deregulation in the industry. Relevant analyses follow.
### Table 5. Effects of Rivalry on Pipelines with Pipeline Regulation Maintained

<table>
<thead>
<tr>
<th>Textbook competition</th>
<th>No rivalry, total regulation</th>
<th>Total regulation</th>
<th>Wellhead deregulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impersonal market forces</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Freedom of opportunity</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Normal profits (p&lt;AC)</td>
<td>Yes</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>*Efficient resource allocation (p&lt;MC)</td>
<td>No</td>
<td>No+</td>
<td>No</td>
</tr>
<tr>
<td>*Efficient production (p&lt; min ATO)</td>
<td>No</td>
<td>No+</td>
<td>No</td>
</tr>
</tbody>
</table>

*Virtually impossible if scale economies exist.

### Table 6. Effects of Rivalry on Pipelines under Regulation and Three Levels of Deregulation

<table>
<thead>
<tr>
<th>Textbook competition</th>
<th>Total regulation</th>
<th>Wellhead deregulation</th>
<th>Total deregulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Impersonal market forces</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Freedom of opportunity</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Normal profits (p&lt;AC)</td>
<td>No</td>
<td>Yes</td>
<td>?</td>
</tr>
<tr>
<td>*Efficient resource allocation (p&lt;MC)</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>*Efficient production (p&lt; min ATO)</td>
<td>No+</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

*Virtually impossible if scale economies exist.
C. Rivalry with Wellhead Price and Pipeline
Operations Both Deregulated (But Contint.
Distributor Regulation)

Free of regulation, the pipeline business would offer
freedom of participation (no certification process), although
scale economies would continue to be a natural monopoly barrier
in entry. Continued distributor regulation, however, makes
it uncertain as to (1) whether current implicit demand
and supply responses to changes in alternate fuel prices
would be effectively (and in timely fashion) transmitted
or (2) whether wellhead price changes would
be transmitted to the end-user market. On the other hand,
as discussed previously, the rivalry actions themselves could
facilitate the desired two-way transfer of market signals.
For this reason, the top "Yes" entry in the fourth column
of Table 6 suggests the reasonable likelihood that market
forces could operate, at least to some extent. Whether pipe-
line profits in excess of opportunity costs will be earned
is not discernable a priori. If there is enough entry by
current firms to cause significant drops (shifts) in demands
facing existing firms, then surplus profits could be elim-
inated, in a manner directly analogous to what occurs in monopo-
listic competition.99 If, however, significant monopoly
power prevails, then surplus profits would persist.

D. Rivalry with Total Deregulation
(Producers, Pipelines, and Distributors)

As regards pipeline impact, the only feature that adding
distributor deregulation to the preceding case brings is
the likelihood that input and wellhead price signals
can be effectively transmitted each way. In other
words, this case coincides with the previous scenario. Conse-
quentially, the "Yes" of that case becomes "No" under 'Total
Deregulation' in Table 6.

VI. Summary and Conclusions

Tables 5 and 6 have stated the conclusions of this
analysis in succinct form. Nonetheless, a brief verbal reca-
pilation is useful:

A. The existence of pipeline scale economies virtually
precludes achieving the resource allocation and overall produc-
tion efficiency benefits of textbook competition at the
pipeline level, either by public utility regulation or interfuel/inter-pipeline rivalry. In practice, therefore,
these two normative standards probably should be ignored,
leaving three "feasible" benefits of competition.

B. The rivalry pipelines are experiencing in today's
gas industry (where all three segments are regulated in some
form) is not a reasonable surrogate for competition—none
of the three plausible benefits of textbook competition occurs.
To the contrary, there is conceptual and practical likelihood
that it may be destructive rivalry.

C. The circumstances under which interfuel and interpipe-
line rivalry would appear to come closest to achieving the
feasible benefits of textbook competition at the pipeline
level are if the three major segments of the industry (produ-
cition, transmission, distribution) were deregulated.

D. Interfuel and interpipeline rivalry, accompanied
by wellhead price deregulation, would seem to be a virtually
"perfect" surrogate for the hypothetical situation of all
three segments in the industry being regulated but without
any rivalry occurring.

The purpose of this paper has not been to advocate either
continuing or eliminating regulation for the U.S. natural
gas industry in general, or for the interstate pipeline segment
in particular. Rather, the intention has been simply to
examine how the price-influencing rivalry actions which are
affecting pipelines today do or do not give the same results
that the price-taker behavior of conceptual competition would
bring. It has been shown, however, that, even though rivalry
instinctively precludes replicating exactly all of competi-
tion's benefits, an operating environment with all segments
of the gas industry unregulated would enable rivalry to be
a closer substitute for competition than is so for other
industry configurations.

Notes

1. Material in this section is, in general, found in text-
books on microeconomics and industrial organization.
A particularly clear treatment is given by F. M. Scherer,

2. Additional traits define the idea of "perfect" competi-
tion: resource mobility, absence of barriers to entry,
input and output divisibility, and complete knowledge
of market conditions. These refinements will not be
part of the discussion here.

3. See chapter 2 of Scherer, Market Structure, for a catego-
ization of the normative features of workable
competition.

4. Price Waterhouse, Houston Area Business Bankruptcies:

6. "Merger Guidelines, Issued by Justice Department on June 14, 1982, and Attorney General's Statement and FTC's Policy Statement on Horizontal Mergers - Special Supplement," Antitrust & Trade Regulation Rev., vol. 42, no. 1069 (Washington, D.C.: Bureau of National Affairs, Inc., June 17, 1982). It should be noted that the aggregate CR values referenced in this paper do not adequately portray concentration in specific regions or producing areas. Such calculations could very well suggest higher concentration, but questions would most likely be raised about the definitions of the areas measured. The purpose here has been simply to report available general indications.


9. The transmission segment warrants more analytic scrutiny, and at the time of this writing the Interstate Natural Gas Association of America (INGAA) is studying competition by examining potential new entry into markets already being served. It is not known when/if results will be available.

10. In general, an oligopolistic market structure exists when there are only a few sellers whose actions affect one another. Pipeline sales for resale would be considered a "homogeneous" (as distinct from "differentiated") oligopoly because gas is a homogeneous product. If there are many sellers who sell differentiated products, then "monopolistic competition" exists.

11. As a point of information, the counterpart cost components (and their percentage shares of burnertip price) during 1982 on Transco's system were: wellhead gas cost = $2.91 (47%); transmission charge = $0.68 (11%); and distributor margin = $2.66 (42%); giving a citygate price of $3.59/Mcf and a burnertip price of $5.25/Mcf. Thus, for Transco, gas costs have been an even greater driving force affecting recent/current citygate prices than has been the case, on average, for the United States.


13. A 1983 survey of member companies by the Interstate Natural Gas Association of America (INGAA) estimated the following aggregate interstate pipeline take-or-pay liability:

<table>
<thead>
<tr>
<th>Year</th>
<th>Deliverability surplus [Tcf]</th>
<th>Liability [1983 $ billions]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1982</td>
<td>0.7</td>
<td>0.5</td>
</tr>
<tr>
<td>1983</td>
<td>2.5</td>
<td>3.3</td>
</tr>
<tr>
<td>1984</td>
<td>1.6</td>
<td>2.3</td>
</tr>
<tr>
<td>1985</td>
<td>0.7</td>
<td>0.8</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>6.9</td>
</tr>
</tbody>
</table>

See INGAA, "The Gas Contracts Problem: Results of an INGAA Survey," Paper #83P-1, May 1983. It should be noted, however, that these values are probably conservative, so that 1983 year-end information would quite likely indicate a worsening situation.

14. Currently, Transco obtains more than 75 percent of its gas from the offshore Gulf of Mexico area, where deliverability and depletion rates are very high when compared to onshore production areas. The following aggregate reserve/production (R/P) ratios data demonstrate this point.

<table>
<thead>
<tr>
<th>Year</th>
<th>Gulf of Mexico</th>
<th>Onshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>1977</td>
<td>9.1</td>
<td>9.5</td>
</tr>
<tr>
<td>1978</td>
<td>6.6</td>
<td>9.8</td>
</tr>
<tr>
<td>1979</td>
<td>7.5</td>
<td>9.4</td>
</tr>
<tr>
<td>1980</td>
<td>7.1</td>
<td>9.7</td>
</tr>
<tr>
<td>1981</td>
<td>7.0</td>
<td>10.0</td>
</tr>
<tr>
<td>1982</td>
<td>7.0</td>
<td>10.8</td>
</tr>
</tbody>
</table>
Tranco purchases gas from some reservoirs which, if they were produced at the take-or-pay minimum rate, could theoretically be depleted in less than one year.

15. INGAA's survey (see note 13) reported aggregate industry projections for take-or-pay-induced citygate price increases of 4.16/Mcf in 1983 and 10.2/Mcf in 1985.

16. For the ISP, which was inaugurated in May 1983, Tranco serves as an agent buying (at marketable prices) and transporting monthly volumes of residual-oil-vulnerable gas in behalf of groups of qualifying distributors from groups of producers who voluntarily choose to participate. In the Contract Carriage Program (CCP), individual purchasers arrange their own deals with producers, and Tranco transports the gas.

17. This categorization can be found in Scherer, *Market Structure*. 

18. Strictly speaking, these economic efficiency arguments pertain to "long-run" equilibrium, a situation that is, at best, difficult to be certain ever exists. Nonetheless, the concepts delineate serve as useful benchmarks.

19. An important technical point is that, by definition and derivation, each point in an average cost function denotes the minimum unit cost of producing the specific output level associated with the unit cost value. Competition's productive efficiency trait thus refers to the "minimum of the minima," so to speak, that is, the production level corresponding to overall long-run average total cost (which, since fixed costs do not exist in the long run, can be viewed as simply "average cost").

20. To illustrate, operating data for Tranco's system during 1983 indicate that unit transmission costs are in the neighborhood of $0.95/Mcf at a throughput rate of 62,000 Mcf/month, declining rapidly to around $0.80/Mcf at about 66,000 Mcf/month, and tending to level at near $0.55/Mcf for flows in the range of 85,000-95,000 Mcf/month.

21. Figure 3, to be introduced in Section V, facilitates understanding these arguments in that it depicts the scale economies concepts.

22. The separate citygate and transmission panels in Figure 3 reflect the fact that a pipeline must sell gas for the same price it pays. That is, the "profit" for a pipeline is only at the transmission level, where there is a regulated return on investment. Thus, the profit-making activity of a pipeline is characterized solely by the transmission function, but the citygate price that "competes" against other fuels and gas sources is made up of both gas cost (the "pass-through" component) and transportation charge.

23. Figure 3's negatively sloped portion of the ATC enables seeing graphically: (1) that for any sales level where transmission charge I would equal MC, losses are assured since I would be less than ATC, and (2) that the sales level corresponding to the overall minimum ATC level could be unattainable. As a point of academic interest, however, the "No" for efficient resource allocation reflects Figure 3's possible situation of price (p<sub>77</sub>) being closer to marginal cost (c<sub>y</sub>) under rivalry than is true for the pre-rivalry sales level (p<sub>75</sub> versus c<sub>y</sub>). In addition, the rivalry-induced sales level g2 lies farther from the minimum ATC sales level than does the pre-rivalry sales level g1. That is, the "No" denotes that rivalry moves farther away from the efficient production level.

The natural gas market today is experiencing oversupply, shrinking demand, and yet continuing increases in already excessive prices. In a competitive market where supply substantially exceeds demand, market forces act to decrease the price. Despite the fact that this has not happened in the natural gas industry, Julian Greene of Transcontinental Gas Pipe Line Corporation (Transco) asserts that the gas producing industry is "probably worksably competitive," and he concludes that "the circumstances under which interfuel and interpipeline rivalry would appear to come closest to achieving the possible benefits of textbook competition at the pipeline level are if the three major segments of the industry (production, transmission, distribution) were deregulated."

On the contrary, the natural gas industry from the wellhead to the burner tip constitutes a classic example of anti-competitive structure and behavior. Moreover, the solutions offered by the FERC to the problems caused by this anti-competitive behavior, as outlined by Kenneth Williams of the FERC, not only fail to eliminate or even mitigate the resulting harmful effects, but also actually serve to exacerbate the injury suffered by consumers.

According to Table 2 of Greene's paper, 1982 retail gas prices were almost five times as high as they had been in 1970. The primary reason for this increase was the fact that 1982 average wellhead prices were 1,400 percent of the 1970 average price level. These higher prices did not result in significant new gas reserves for the interstate market, but instead merely gave the producers too great an incentive to drill developmental wells for gas that was already available. Much of this gas had been held off the interstate market by producers during the 1970s to create the artificial gas shortage that led to the passage of the Natural Gas Policy Act of 1978 (NGPA), with that statute's substantial price increases for partial deregulation of producer sales.

This is shown in Greene's Table 3, which depicts Transco's reserves, production, and deliverability for 1978 through 1982. While Transco's reserves increased by only 9.8 percent during these years, the deliverability of those reserves increased by 107 percent. As a result, Transco's reserves/production ratio and reserves/deliverability ratio dropped precipitously from 1978 to 1982, from 10.1 to 6.7 and from 10.1 to 5.4, respectively.

Thus, Williams declared at the outset of his paper that "the incentive prices under the Natural Gas Policy Act (NGPA) and the availability of markets initially stimulated a high level of well drilling activity. Unfortunately this activity was directed primarily toward developmental wells with the consequence that we were able more rapidly to produce existing reserves rather than find new reserves."

In addition to the NGPA's allowance of extremely high prices for already discovered gas, the inclusion in contracts between producers and pipelines of high percentage take-or-pay provisions also spurred this artificially increased deliverability of existing gas supplies, even though no markets existed for this additional gas. As Greene notes, these take-or-pay classes are based on deliverability and not reserves. Therefore, if a producer is able to increase the deliverability of its gas supply, the take-or-pay requirement can be increased above 100 percent of the level originally anticipated as the amount available under the contract. Greene emphatically points out that because of these excessive take-or-pay provisions to which Transco and other pipelines agreed in their contracts with producers, reservoirs may be depleted in a very short period, and, in fact, the deliverability levels are so high that Transco does not even have the capacity to deliver all of the take-or-pay gas that it has contracted to purchase from producers:

Transco purchases gas from some reservoirs which, if they were produced at the take-or-pay minimum rate, would theoretically be depleted in less than one year.

Excess deliverability occurred in 1980, and it quickly worsened to the point where the tendered volumes of over 1.2 TCF per year...
actually exceed Transco's pipeline capacity 
even if there had been markets for such 
volumes.

Greene does not explain why, in this supposedly competi-
tive market, Transco agreed to such onerous take-or-pay 
clauses, in addition to agreeing to pay excessive prices 
for natural gas. It is important to recognize that the NGPA 
did not regulate nonprice provisions of contracts. Transco 
and other interstate pipelines were free to bargain at arm's 
length with the producers for all nonprice contract terms, 
such as take-or-pay. Also, under the NGPA, only maximum 
tariff price ceilings were established. Thus, the producers 
and pipelines could have agreed to prices below the statutory 
celling price levels, and they also could have negotiated 
prices that did not exceed the market-clearing level for 
dereregulated purchases under Section 107 of the NGPA. However, 
with few exceptions, such bargaining did not take place, 
and it did not take place because of the anticompetitive 
structure of the natural gas industry.

At the wellhead, the producing industry has been an 
oligopoly controlled by the major oil companies. Recently, 
the concentration of economic power in the major oil companies 
have become even more substantial with the merger agreements 
of Texaco Inc. to acquire Getty Oil Company, of Standard 
Oil Company of California to acquire Gulf Corporation, and 
of Mobil Corporation to acquire Superior Oil Company.

In addition to oligopolistic control of natural gas 
production and reserves, the major oil companies are horizon-
tally integrated so that they control the alternate fuels 
to natural gas, such as oil and coal. Moreover, these are 
the same multinational corporations, which together with 
OPEC, control the international price and production of crude 
oil. It should be emphasized that deregulation of domestic 
natural gas prices will remove U.S. government control over 
these prices, but will substitute in its place price control 
of domestically produced natural gas by the OPEC governments 
through their cartel pricing of international crude oil.

In addition to horizontal integration of the oil company 
producers, the natural gas industry also suffers from vertical 
integration of pipeline companies into the production of 
natural gas themselves or through affiliated companies and, 
in some cases, into the distribution of natural gas as well. 
Thus, wellhead to burner tip vertical integration exists 
in the natural gas industry.

The pipelines have shared the interests of the producer-
sellers of natural gas as a result of their own and their 
affiliates' production, and they have had no interest as 
buyers of natural gas as to the prices they have paid and 
the take-or-pay conditions they have agreed to as a result 
of the FERC's allowance of automatic purchased gas adjustment 

pass-throughs and end of the inclusion of take-or-pay provisions 
in the rate base. Consequently, both the seller and the 
purchaser in contracts for first sales at the wellhead have 
had the interest of the seller and not of the buyer, and 
the consumers have paid dearly for this anticompetitive market 
condition.

Moreover, pipelines are monopolies in much of their 
service territory and at least oligopolies in those locations 
where one or two other pipelines may also serve the same 
distributor, and the distribution companies are monopolies 
at the retail level. Thus, neither pipelines nor private 
distributors particularly care how much consumers must pay 
for natural gas, unless and until the price of natural gas 
becomes higher than the price of alternate fuels for those 
end-users which have installed alternate fuel capability.

Pipelines and private distributors are not today pleading 
the case for lower wellhead prices of natural gas because 
they are appalled that price gouging is occurring at the 
wellhead, but only because the price of natural gas at the 
burner tip now exceeds in many markets the OPEC cartel 
price for No. 6 fuel oil. If the OPEC price had continued to rise, 
such that it had remained above the rolled-in, average gas 
acquisition price of interstate pipelines, the pipelines 
and private distributors would see no problem with today's 
excessive gas prices. Pipelines would have continued to 
execute contracts for the purchase of $9.00 and $10.00 per 
MMBtu Section 107 deregulated gas if they could have rolled 
in those gas costs with the cost of their other gas supplies 
and obtained a resulting average price that was below the 
OPEC price for oil.

In addition, despite continued conservation by residential 
consumers, there is a certain inelasticity of demand for 
heating, cooking, and hot water which necessitates natural 
gas purchases by locked-in residential consumers regardless 
of the price of natural gas. Furthermore, certain industrial 
feedstock and process users must utilize natural gas and 
cannot burn alternate fuels. With this inelasticity of demand, 
it is not possible for the marketplace to set a competitive 
price level which would be equivalent to the price that would 
result where all consumers had elastic demands and could 
simply walk away from natural gas if the price is too high 
and instead purchase a competitively priced alternate fuel.

It must also be recognized that this inelasticity of 
demand exists not only as between natural gas and other fuels, 
but also as to which supply of natural gas to purchase.

Consumers behind a particular distributor of natural gas 
are locked into purchasing their entire supply of natural 
gas from that distributor. They cannot purchase this same 
fuel from another retail supplier because of the monopoly 
that their distributor has.

It appears that Congress and the FERC have forgotten
that the purpose of enacting the Natural Gas Act of 1938 was to protect residential consumers with inelastic demands "against exploitation at the hands of natural gas companies" (Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 610 [1944]). Certainly, natural gas company producers are even more powerful today than they were in 1938, and the deregulation allowed by the NGPA has shown the gross level of exploitation which has already been reached and will only be increased if producers' sales are further deregulated, as is now called for on January 1, 1985, by the NGPA.

Williams discusses the actions taken by the FERC in light of the serious market disorder caused by the excessive prices charged by producers in the face of oversupply and decreasing demand. Completely absent is any action by the FERC to deny pass-through of costs by pipelines or a decision to reduce or eliminate the effect of the take-or-pay requirements in pipelines' contracts with producers. Williams does not mention that the anomalous situation which exists in the natural gas industry today is a product of the pipelines' failure to act as true buyers in a competitive market to keep prices down and to retain flexibility to reduce their takes from sources to a lower level if demand decreases. Pipelines agreed to pay prices equivalent to 110 percent to 130 percent of No. 2 fuel oil prices for gas from producers at the wellhead--which prices conveniently also applied to the pipelines' purchases from their producing affiliates and their own pipeline production as well--and then acted shocked that this gas could not be marketed to end-users with significantly lower priced No. 6 fuel oil as an alternate fuel.

Plainly and simply, the FERC has insulated pipelines as buyers through automatic PPA pass-through and the inclusion of take-or-pay prepayments in the rate base and bestowed upon them the power to eliminate the commodity component of their rates if they did not sell the volume of natural gas on which their rates were designed. Under the United Methodology, 75 percent of the fixed transmission and storage costs and 100 percent of the fixed production and gathering costs were included in the commodity component. Inexegantly, rather than attempting to increase the risk upon the pipelines to give them the necessary incentive to keep their gas costs down, Williams reports that the commission has instead begun adopting a so-called modified fixed-variable rate design, which places only 300 percent of the return on equity and related taxes together with the fixed production costs in the commodity component (amounting to only approximately 25 percent to 30 percent of the total fixed costs), while all other fixed costs are placed in the demand component. Thus, what little pipeline risk existed because of the utilization of the United rate design methodology is reduced to an absurdly low level with the utilization of the modified fixed-variable methodology.

Of course, with this removal of risk from the pipelines through the removal of fixed costs from the commodity component, any short-term savings by industrial end-users and other high load factor customers will be offset quickly by higher purchased gas adjustment cost filings. Pipelines can then pay producers more and still arrive at the same commodity level; yet, the risk on the pipeline for paying too much is drastically reduced under the modified fixed-variable methodology. Consequently, the locked-in, full requirements distributor-customers of pipelines and high priority residential consumers will pay increased rates twice, first by the shifting of fixed costs to demand under the modified fixed-variable rate design, and second through higher purchased gas costs to producers. Williams admits that this fixed-variable approach to rate design was employed by the commission in the 1940s when there were capacity constraints "to send signals to those that would impose additional capacity requirements as to the true cost of that capacity." But today, the signal which desperately needs to be sent is the extremely high cost of gas at a time when unused capacity exists, not a signal regarding delivery capacity, which is a sunk cost that is totally overshadowed in today's gas market.

In fact, because of rolled-in pricing, the wrong price signal is sent to consumers and producers even if 100 percent of the fixed costs are placed in the commodity component of a pipeline's rates. The replacement cost of gas is above the average cost of gas, and it is for the high load factor customers that the incremental gas supply is obtained. Thus, the FERC should be doing everything in its power to send the signal to both the end-users and the producers that the price of new gas at the wellhead is far above the level which competition would set, as evidenced by the lack of demand at the higher price level.

Williams also discusses the Industrial Sales Programs (ISP) and the Contract Carriage Programs (CCP), which are types of Special Marketing Programs (SMP) that the FERC has approved for various pipelines. Under these programs, producers are given the opportunity to lower their prices solely to those markets which would not otherwise be served at the average cost of gas of the particular pipeline. These programs worsen an already terrible anticompetitive situation for several reasons.

First and foremost, they send to the producers the absolute opposite price signal from that which is required. Producers need to be told that they must reduce their prices
across the board to all customers at least down to the market clearing price level in order to be able to sell their product. This is what happens in competitive industries, where a commodity is priced to attract the marginal customer and the advantage of that lower price is obtained by all of those who purchase the product.

However, these SMFs signal the producers that they need not reduce the price to the margin for all users but only for those which can use No. 6 fuel oil or which otherwise will not purchase gas from the interstate pipeline at the average cost of gas. A producer thus can reduce its price just for a particular group of customers and can continue charging excessive prices to the remaining locked-in consumers on the pipeline system. In fact, with the No. 6 fuel oil users being served under the SMFs, producers and pipelines can then utilize the No. 2 fuel oil price as the rolled-in price level for the remainder of their pipeline system sales. This creates a new dual market between No. 6 fuel oil end-users and the other consumers on a pipeline's system.

The invidious results of this anticompetitive, value-of-service pricing are currently being seen, for example, on the Transco system, where Transco has filed to continue its ISP and CCP discount sales program for its marginal end-users, while at the same time putting into effect on April 1, 1984, a rate increase for its general system supply customers. These SMFs are the antithesis of incremental pricing, and they are also wholly at odds with curtailment plans. Under the curtailment plans that had been approved for the various interstate pipelines, it was assumed that the last and most expensive increment of gas supply was obtained for the lowest priority end-users with No. 6 fuel oil alternative fuel capability. Thus, when there was a shortage of supply, it was these end-users which were curtailed first. In stark contrast, under the SMFs, the discounted increment of gas supply is reserved for the lowest priority end-users, and the locked-in customers must purchase the more expensive general system gas supply.

In sum, Greene of Transco and Williams of the FERC have clearly demonstrated that neither the pipelines, as purchasers, nor the FERC, as the federal regulatory agency, has protected, is protecting, or intends to protect consumers from the anticompetitive effects of the natural gas industry. Consequently, excessive prices continue to exist in a time of oversupply and declining demand. These problems will only worsen when further substantial deregulation of producer-prices occurs on January 1, 1985, under the NGPA.

COMMENTS

Thomas J. Norris

The papers by Kenneth Williams, Virginia Sheffield, and Julian Greene are all concerned with what is happening in today’s natural gas markets. To understand more fully what they have said requires reflection upon the historical development of that market. Until the 1970s that history could best be described in terms of growing demand and stable prices. During the 1970s the demand continued to grow, but the natural gas share of the market declined as gas supplies did not keep pace with the growing demand for energy. Price regulation, which kept natural gas wholesaler prices at artificially low levels from the advent of price regulation in the mid-1950s until the passage of the NGPA in 1978, was primarily responsible for the lack of gas supplies available to the interstate market during the 1960s and 1970s. The supplies that were available were the subject of intense competition among pipelines. Since the price was regulated, the pipelines competed with one another on nonprice terms. During the early 1970s interest-free advance payments were often employed to induce producers to commit gas reserves to a particular pipeline. Other inducements included processing rights and rate-of-return provisions. Producers have always been vitally concerned with cash flow, and while pipelines could not bid more than the maximum lawful price, they could contractually agree to purchase the gas at a percentage of deliverability, thus guaranteeing the producer’s cash flow; the higher the percentage, the better. Most pipelines offered contract terms obligating them to purchase 85 percent
or more of whatever the producer could produce. This was not a problem since pipelines were able to sell every mcf of gas they could acquire and even then were unable to satisfy contractual agreements completely.

During this same period, worldwide demand for energy of all types was increasing faster than new energy sources could be brought on stream. Then, as a result of the 1973 Arab-Israeli conflict, an embargo on oil sales to the United States was imposed and spot market prices jumped to astronomical levels and remained there after the embargo was lifted. Postembargo prices were roughly six times the earlier levels. Demand for energy in the United States did not respond to this dramatic price change, and a perception began to grow that demand was price inelastic. Interstate natural gas prices, however, had not risen proportionately with oil prices, and thus there was created an additional, large, unsatisfied demand for natural gas. The federal government responded to this demand-supply imbalance by increasing the price for newly discovered natural gas and then by legislating the Natural Gas Policy Act of 1978. Increasing quantities of natural gas were made available to the interstate market, slowly at first but with increasing momentum as the NGPA price incentives began to take effect.

With increasing supplies came increasing prices, but the industry was not alarmed since natural gas still enjoyed a very substantial price advantage over competing oil supplies. During this same period the Iranian revolution had disrupted oil supplies, and oil prices had tripled. Energy demand did not diminish, and natural gas enjoyed a price advantage that many thought would continue almost indefinitely. Federal regulation, which set pipeline natural gas prices, was in effect. Pipeline natural gas was the only available natural gas in order to meet existing contract demands. Pipeline customers purchased and resold all available gas the pipelines made available at the ever-increasing prices.

Meanwhile, forces were at work which most of us had not anticipated. The latest round of oil price increases had triggered double-digit inflation which ultimately led to the severe recession. The industry shut down permanently closed many of its least efficient operations, and began to scrutinize all of its operating costs. Energy was one of its first targets. With the recession came a worldwide reduction in industrial energy consumption, although industry was not alone. Households and commercial establishments, through added insulation, thermostat cutback, and the use of more efficient equipment, had been gradually reducing consumption since the early 1970s. In the automotive area, the increased percentage of fuel-efficient foreign vehicles and the improved fleet fuel efficiency of U.S. vehicles substantially reduced gasoline demand. At the same time as forces were operating to lower energy demand, new supplies were added, for example, from the North Sea. Once again equilibrium was lost, and adjustments to prices were required this time downward.

Gas prices were, however, continuing upward. NGPA-established prices continued to increase with monthly escalations tied to inflation. Substantial quantities of deregulated gas had become embedded in the mix, and less and less "cheap" gas was being purchased. The natural gas market was rudely awakened. Total energy demand declined, and the natural gas market, which had allowed its costs to creep close to competitive fuel prices, was caught when oil prices fell. Demand dropped as loads were lost to alternate fuels. Pipelines were unable to sell all the gas made available to producers. The producer shut in the least expensive gas, prices rose, and demand fell further. The producing industry, which had responded to NGPA stimuli to exploration and development, was bringing new supplies to market when existing supplies already exceeded demand. This "gas bubble" was expected to last four to five years. Some small independents and their bankers had gone bankrupt. In short, the industry was in turmoil.

The pipelines which had earlier signed high take-or-pay contracts based on then current market signals were now faced with staggering obligations. Under existing regulatory practices natural gas could not reclaim its market, which had been lost to alternate fuels. Pipelines began to seek ways to market gas in order to avoid take-or-pay provisions, which if incurred and reflected in rates would exacerbate existing market problems. Rate design changes, off-system sales, and special discounts were the first examples. Then came the incentive sales programs (ISPs) and the special transportation rates.

As Williams described, one of the more fundamental questions the FERC must face is the apparent discrimination between those customers who can avail themselves of the direct benefits of these special programs and those who are captive customers and therefore receive no direct benefit. The commission has responded by insisting that the captive customers receive at least some indirect benefits, such as lower take-or-pay requirements or lower base rates due to increased pipeline throughput.

My company, Tennessee Gas Pipeline, has formulated one such proposal and is in the process of seeking FERC approval. However, before embarking on its ISP plan, Tennessee first took steps to control both its gas costs and its take or pay through an emergency natural gas purchase policy (EGP). Gas costs were reduced and controlled at the lower level by taking control of the quantities of low cost and high cost gas delivered by the producers to Tennessee Gas. The company then established a 70 percent take level for low cost supplies.
and a 50 percent level for high cost supplies and agreed to pay take or pay if purchases fell below those levels. We have been able to obtain agreement to this plan from a majority of our producers. We immediately lowered our gas costs by about 15 percent, and with prices below most competing fuels we were able to regain a substantial load during the second half of 1983. However, there remained another market which was unobtainable through conventional means, and we designed an ISP program called TEMPO (Tennessee's Emergency Marketing Program) to try to reach that secondary market.

As Williams described, a number of ISPs have been put before the FERC, including one by Tenneco GTI Company, Tenneco's producing subsidiary. These programs have been quite controversial, and major questions have been raised as to discrimination between classes of customers and as to the markets which should be open to these programs. The competitive question gets into the areas Julian Greene discussed.

These are difficult issues which the FERC will ultimately have to address. I simply raise raising questions, not proposing solutions, although I believe that my company's position can easily be gleaned from its application for TEMPO. Among the questions to consider are:

(1) Should the ISP be made available to any pipeline desiring to operate one, or should it be restricted to only those with actual or imminent take-or-pay problems? In other words, is the creation of a two-tier market an idea whose time has come, or is it worthwhile only because of the present difficulties?

(2) Is NACOS a better standard than an NGPA price category? For example, is it reasonable to let one pipeline release NGPA Section 103 gas for sale under an ISP but deny another pipeline whose NACOS is higher?

(3) Should gas be released for sale based strictly on its maximum lawful price, or should some vintage mixing be permitted?

(4) Should pipelines be required to charge full cost of service rates for service that is out of interruptible?

How should the avoided cost attributable to avoided take or pay be recognized? Why should third-party transportation charges be included in the pipeline transportation charge if the participating producer is absorbing those costs under the ISP?

(5) Should gas-to-gas competition be permitted or even fostered? Who wins? Who loses? Should markets be restricted to those currently burning alternative fuels?

(6) What do we hope to gain from the ISP experiment? Insight into marketing? Lower rates for captive customers? Transmission of price signals to producers? Assistance to pipelines to work out of take or pay?

These are not particularly easy questions, but the FERC must answer them, beginning with the last. It is only by first defining goals that a program can be designed for their achievement.

The questions concerning competition raised by Greene are equally intriguing and must be addressed at least in part in arriving at the final design of the ISPs. Competition is not new to the natural gas industry; it is simply an element that has not been highly visible for some time. It is highly visible today, however, as pipelines find themselves with more gas than market. The only way to increase sales significantly is at the expense of other pipelines serving the same market. Since the only ways to differentiate among pipelines are price and service, those elements will be the key to success over the long run. In the short run, price will dominate. Over the past decade pipelines scrambled to adjust rates upward in light of declining volumes caused by curtailment and rising prices. The challenge today is to hold prices down to maintain or increase market share. At this point I should like to mention an FERC practice that serves to limit price competition, the staggered PGA filing system. During periods when gas prices are changing upward or downward, pipeline rates tend to play leap frog with first one then another system enjoying a price advantage. The low cost pipeline may or may not be able to enjoy the fruits of its effort to hold down costs. Medically may be rewarded.

The last area for comment is the elasticity study presented by Sheffield. I do not pretend to be an expert in statistics, but I would like to make some general comments on the relationship between price and natural gas demand which I have observed.

First, with natural gas as with everything else, changes in price cause related changes in the level of demand. The trick here is to measure the response over sufficiently long periods to obtain accurate data. Decisions to reduce consumption by making capital expenditures do not manifest themselves in outright reduction in usage. The momentum started by the first price shock in 1973 is still being felt in some areas. Changes in housing stock are being accompanied by lower usage because the newer housing is more energy efficient than the housing it replaced. Similar phenomena are being experienced with respect to appliances. A new generation of household appliances much more energy efficient than their predecessors was spawned in the early 1970s. These newer devices are still replacing older, less efficient units. Thus, the replacement over time of older housing and appliances continues to contribute to lower and lower per capita energy consumption. How price shocks may spawn a new generation of still more energy-efficient devices, but lower energy prices will not cause increased consumption.

Second, the energy conservation phenomenon is in large part irreversible. The reduced consumption levels attributable
to more energy-efficient capital goods are a permanent reduction in consumption levels; no one will scrap new equipment to buy less efficient equipment. Thus, capital-related conservation is a one-way street. Reductions obtained through changes in habit, such as thermostat set back, while not necessarily permanent, are relatively firm in that people adapt to new life-styles and are unlikely to revert quickly to older habits absent some dramatic event.

Indeed, energy consumption is price elastic in many ways that are difficult to assess using traditional statistical measures, particularly in the industrial area, where demand is affected by many things not directly attributable to price. During the past few years U.S. industry has been in recession, particularly "smokestack America." Typical of smokestack industry are steel and automobiles. In recent years these industries have been severely depressed as a result of foreign imports, changes in style, shifts in technology, and the general economic climate. The change in energy demand caused by the influx in great numbers of Japanese automobiles, which directly affected a number of other industries (notably steel), cannot be explained purely in price terms. Similarly, the downsizing of the average size of the U.S. automobile fleet, while somewhat related to price and scarcity of fuel supply, is more a response to legislation than current prices, but the effect is the same. Smaller cars require less steel and less energy to produce. Advances in technology enable manufacturers to substitute lighter, less energy-intensive parts and processes. These factors have all contributed to reduced industrial demand. As U.S. industry emerges from the recession, demand will increase for a time. At some point during this recovery, industry will again spend capital dollars to revitalize older industrial processes and equipment. As this begins to happen, industrial consumption may again drop as new efficiencies are introduced. One has only to look at the Japanese manufacturing processes to gain an insight into the productivity gains available to U.S. industry from modernization.

Part Ten:
Potential Effect of Imposing
Common or Contract Carrier
Status on Natural Gas Pipelines
The natural gas industry demonstrates a fundamental paradox. The price of natural gas at the wellhead is falling for the first time in history. At the same time, pipeline companies are contractually bound to pay for $3 billion worth of expensive gas this year that they cannot use. These long-term contracts were signed in the 1970s when gas supplies were scarce. The pipeline companies did not compete on the basis of price but instead competed for supplies by promising to pay producers for greater and greater percentages of yearly production capacities. Producers responded to these take-or-pay contracts by drilling more wells in existing reservoirs, raising capacity, and thus increasing the volume obligations of pipelines. With the passage of the Natural Gas Policy Act of 1978, many price categories of gas were deregulated, and the pipelines paid producers higher and higher prices in order to have sufficient supplies to put into their transportation systems. In many cases they also bid up the take-or-pay provisions to 90 percent of producer capacity, and contract terms of twenty to thirty years were not uncommon. The regulatory authorities, faced with the problem of curtailment and prorationing, were enthusiastic advocates of many of these strategies. As long as the gas shortages continued, there was little regulatory interest in changing the organizational structure of the industry.

Today there is too much gas. Total U.S. gas consumption...
Pipelines as Contract Carriers

The benefits to buyers

Given the current natural gas glut, pipelines are unable to buy new sources of gas costing $2.00 to $3.00 per Mcf while paying under contract three to four times that much for gas. Two sections of the industry are upset by these circumstances. The producers whose gas is turned away are bothered. Most are tied to only one pipeline and are unable to sell elsewhere. The producer is concerned because its obligation is to buy gas as cheaply as possible at the city gate. They, too, can buy from only one pipeline company. The pipeline is effectively a monopoly buyer in the gas field and a monopoly seller at the city gate. For these reasons, the proposal will yield two major economic benefits: a reduction in the monopoly power of the pipeline and a lower price for gas delivered to the customer.

Because the market price of gas in the field is considerably less than the gas prices that pipelines offer their industrial and distribution company customers, these buyers would avoid the pipeline's monopoly price by contracting directly with suppliers. This would allow more competition on the buyer and seller sides of the market. With deregulation of the field price of natural gas, it could be argued that buyers should be given the opportunity to buy from any seller and to seek the lowest equilibrium price. Only in this way would we be certain that the major benefits of field deregulation and deflation are passed on to end-users. A requirement that the pipelines would have to transport this lower priced gas would be the necessary structural change to bring this about.

Where the structural change has been allowed, there has appeared a strong market response on both the buyer and seller sides. For example, one pipeline company, Transco Energy, has begun to act as a broker arranging one-month spot sales and charging a transportation fee. It is already moving 250 Mcm a day in this way. Panhandle and Midcon Corporation also are developing gas-broking programs. Washington Gas Light, a distributor, is buying about half its gas from sources other than pipelines during the light summer season. The Columbia Gas System currently transports about 140 Mcm a day for industrial and wholesale consumers who deal directly with low cost suppliers. Transported gas now represents 12 percent of Columbia's throughput. Yankee Resources, Inc., the largest of the independent gas marketers, is moving 60 Mcm a day. From 1975 through 1980, the pipeline industry's volume of transported gas increased 138 percent.

It is clear that the contract carrier arrangement is rapidly gaining a significant foothold in the pipeline sector of the industry. The potential benefits are great, and the marketplace is responding. The two necessary conditions are vigorous competition in the field and spot prices below the gas prices that pipelines offer.

Another potential benefit offered by contract or common carriage is that load factor considerations of distribution companies are given greater weight. Because the purchase contracts are in the hands of the distributors, their interests will not have to rely on the pipeline supplier acting as their agent. This arrangement has not been optimal where the pipeline company has its own differing set of load factor considerations. Common carriage would mean greater cost efficiencies in operations for the distribution companies. Industrial consumers would gain the most under common or contract carrier arrangements. Because of their strong ability to pay and large demand requirements during off-peak, they could best capture the available supplies. This structural change leading to substantially lower prices would be in their best interest. The social benefit would be greater employment and output in industries which use a large amount of natural gas in their operations. Evidence of the significance of this benefit can be documented by the case of Indiana Glass Company, which had laid off 1,000 workers and shut down most of its business partly because of high gas prices.

Recently, it rehired 650 employees and resumed normal operations when it found a cheaper source of gas through a gas broker.
A final benefit is that natural gas is now more competitive with alternative fuels. This is likely to increase the use of natural gas for industrial purposes and as a result reduce our dependency on oil supplies and enhance our environmental quality since gas is clean burning.

To summarize the benefits, contract carriage will reduce the monopoly-monopoly power of the pipelines and lead to substantially lower prices for natural gas. Because the pipeline company will no longer represent the distribution company in the same way, there is likely to be greater sensitivity to the load factor economics of the distribution company and lower costs of operations. Other significant benefits are: an increase in the level of industrial employment, a more competitive position in relation to alternative fuels, and enhanced environmental quality.

The Costs of Contract Carriage

Analysis of the potential costs of contract carriage must focus on the functional role of the pipeline company in the industry. The transportation of natural gas over a pipeline's network is its primary task. Equally significant and often overlooked is the merchant function between the gas producer and the distribution company. Over time, the pipelines have built up a considerable understanding of the marketplace for natural gas. They perform a valuable service by contracting with a large number of suppliers to bring into realization an assured source of gas for end-users. It is this obligation to serve or meet the demands of end-users and to search out scarce supplies that is the pipeline's merchant role. This obligation would be shifted under the contract carriage recommendation. In addition, the availability of natural gas through contracts to fill the pipeline may no longer have to be considered in certificates of convenience and necessity. The burden of arranging for adequate natural gas supplies would shift almost entirely to distribution companies and industrial users.

If the natural gas glut is likely to become a shortage in the future, and if contract carrier status is imposed on the pipeline companies, significant economic costs could arise. The distribution companies and the direct industrial buyers of gas would be in serious competition with one another for the limited amounts of gas available in the field. History confirms this prediction in the emergency shortage of gas during winter 1975-76. In that shortage the FERC found it appropriate to allow pipeline transportation arrangements so that industrial independent requirements for gas for their operations.

The industrial concerns entered the field markets in significant numbers and were able to buy 6 Mscf of gas during the five months of that winter. Their strong ability to pay allowed them to take these amounts away from the intrastate buyers of new gas. Even though the interstate pipelines did not lose sales volume in consequence of the policy, they opposed a continuation of direct purchases into the next year. Their position was that a continuation would place them at a competitive disadvantage in securing additional supplies. What this historical example shows is that the direct industrial buyers would have squeezed out the pipeline companies from scarce supplies. A parallel circumstance could exist under contract carrier status. The distribution companies in place of the pipelines would have to compete with the industrial buyers for the limited resource. The probability is great that they would lose supplies because of an inferior ability to pay. Given that the highest priority end-use of natural gas is residential consumption, and given that the supplier to the burner tip is the local distribution company, the net economic benefits of the competition for limited supplies could well be negative. Contract carrier status for the pipelines would create uncertainty that residential demand and its growth could be met.

One could argue that the distributors have considerable ability to compete in the supply markets for gas and that they may not be at any competitive disadvantage. Therefore, the previous concerns are unimportant. This position assumes that all distributors are large and contain a considerable commercial/industrial customer base that will support a strong capacity to pay. The facts are that there are many small distribution companies serving communities with a low population base and few industrial customers. These buyers would be seriously harmed by a policy of competition for scarce supplies. It is likely that these companies will be crowded out by industrial and large distribution companies.

On a lesser note, one must ask what will happen to the numerous, small volume, nonjurisdictional buyers who tap the pipeline that passes their farm or plant. An alfalfa drying plant's management may not feel that it will purchase agreement or brokerage contract is worth the effort.

The end result of the first economic cost is clear: We would see the rise of gas brokers or intermediaries. This would not be a new economic activity or unique from the traditional pipeline transaction. Rather, we would be letting the gas broker perform the merchant function in place of the pipeline company. The question that needs to be asked is why this institutional arrangement would be any more economically efficient than the old one. Because of large capital sunk costs and because of winter/summer load considerations, the gas pipeline company has a strong incentive to find gas to put into that transportation system. In addition, interregional industrial sales are strongly competitive with alternative fuels. The gas broker or intermediary will not approach the field transaction with the same set of concerns.

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One obvious difference would be a preference on the part of the broker for short-term contracts. The frequency of buying negotiations would strongly influence the income to the intermediary. With the present gas glut and deregulation of the field price, this particular bias toward short-term contracts could benefit end-users. However, any reversal of this supply situation could prove disastrous to residential users.

Another difference with gas brokerage is a change in sensitivity to load factor. Under the present arrangement the pipeline buys gas in the field in such a way as to maximize a high load factor for its operations and to a lesser extent as a stand-in for the distribution company's load concerns. The buying decision does consider the distribution network's load factor in the sense that the pipeline company has the obligation to meet the final demands of its customers. But the 'agency' concept is reversed under brokerage. The broker acts as the distribution company's agent and would be concerned with the peaking problems at the city gate, which may not be the same as the load factor considerations for the pipeline. This would be the case where the direct industrial buyers by-pass or do not utilize the distribution network. As a result, there would be less likelihood that the timing decisions of the pipeline and the distribution companies would be compatible.

One interesting regulatory question about gas brokerage is: Should we allow the pipeline companies to become the intermediaries, or should we encourage the growth of independent gas marketers? If contract carriage is allowed for the pipeline sector, then I would have serious reservations about an institutional arrangement that would allow them to dominate the brokering of natural gas as well. If one believes that the supply would be taken away from the pipelines to increase competition in the industry, then it makes no sense to turn around and allow the pipeline companies to be the brokers. This would negate the monopoly-reduction which was one of the major benefits of contract carriage status.

Besides merchant function considerations, an equally major potential economic cost is the instability to handle the problem of gas curtailments or shortages. Contract carrier status may not be feasible if more gas is presented for transportation by the direct buyers than the capacity of the pipeline permits to be moved. The implementation of prorationing and the pipeline's function will be the issue. Before, the pipeline had to worry about getting the gas to market and then deciding the priorities of claim; now it faces the decision of whose gas it should consider for transportation. One should remember that a large interstate pipeline company may buy gas from 2,000 suppliers and sell to 20-25 major buyers. To shift the prorationing decision to the field may make the regulatory task nearly impossible unless the intermediaries are severely restricted in number. Congestion and its resultant economic problems may be causes to reject contract carrier status for the pipeline industry.

When the pipelines give up their merchant function to brokerage companies or intermediaries, there is likely to be a significant increase in the transaction costs borne by the end-users. These costs would include support for the various committees needed to develop and execute supply contracts, enforcement, and record maintenance regarding available supplies, transportation flows, and demand conditions. The committee support necessary for proper coordination between the broker and the distribution company is inherent in all contract carrier arrangements. But committee decision making can be time consuming, and the difficulties of aggregating preferences are well documented. Transaction costs are less tangible than capital and operating costs, but they are important. Upon entering into a brokerage arrangement, the latitude enjoyed by an end-user in making decisions may well decrease. This loss of flexibility is a very real cost.

Another regulatory concern could be raised about the contract carrier proposal. Once the pipeline network became available to all comers, there would be an incentive for the largest customers of the distribution companies to by-pass the local network and hook up directly with the interstate pipeline. Then issues of equal access to the pipeline network would become prominent. One sees the identical pattern developing today in the telephone industry, where deregulation of the long distance network is encouraging by-pass of the local exchange network. The consequences of by-pass on the distribution company's load factor as well as diversity factor would be negative. As a result, remaining customers would have to pay more for their gas deliveries, and the distribution company's ability to compete for scarce supplies would be weakened.

How would this proposal to allow large industrial users to bargain directly with producers handle the by-pass problem? One solution is to make it much more difficult for industrial gas users to disconnect from the local distribution companies currently serving their plant. However, this solution would mean that the gas industry would have two transportation fees, one for the pipeline sector and a second for the distribution company. Many of the same concerns noted above should be expressed for evaluating this second tier of transportation charges. For example, consider an industrial buyer who rejects the interruptible sales contract and wants firm deliverability...
of the gas during the winter season, when the distribution company may not have the capacity to serve. I seriously doubt that many of the industrial users will be interested in an interruptible supply arrangement. This would represent a major departure from the past situation. If this preference for firm deliverability were to come about, the industry would face an even more serious problem of assigning capacity on the pipeline systems, both interstate and local. An industrial gas customer, with interest in firm supplies, may have very strong reasons to by-pass the distribution network. Restrictions on access to the interstate pipeline may create considerable enforcement costs.

At this point, a different potential economic cost needs to be discussed. Under the present industry structure the gas pipeline company sells to the resale buyer under a two-part rate form: a demand charge and a commodity charge. The demand charge penalizes poor load factor buyers and also discourages peak use. In contrast, the transportation tariff used by the industry follow a simple straight-line rate form based on cost per mcf delivered, with no specific recognition of natural gas characteristics. If the pipelines are removed to contract carrier status, there is a strong likelihood that not only would this form for transportation charges, namely, a straight-line rate structure for all end-users, the result for regulatory economics would be a significant step backward from price discrimination based on cost-sensitive pricing.

If contract carriage were to be implemented in the industry, one could wonder about the future of “exchange” gas. The tariffed form of ownership is not subject to an ownership change in the transactions. These are transportation gas (T series) and exchange gas. Transportation gas is simply natural gas transported for other pipelines over the systems in which ownership of the gas by the transmitter is not changed. Exchange gas is received by one pipeline company at one delivery point, and it then is required to satisfy the exchange balance by deliveries back to the original pipeline company or one of its customers, usually at a different geographical point. These exchange amounts must balance over a certain period. It seems to me that there would be no need for exchange gas under contract carriage. Where there might be a social loss is in the disappo.. An incentive for the pipeline companies to minimize transportation miles through interconnection. From 1975 through 1980, the pipeline industry's volume of exchange gas rose 69 percent, from 3.6 Tcf to 6.1 Tcf. Given the volume of exchange gas should be concerned about the implications of its disappearance under contract carriage.

A final cost consideration in the evaluation of the proposal is that a national emergency on shortage of natural gas would be much more cumbersome to handle with a large number of buyers in the field portion of the industry. Switching to other, unfamiliar sources would present an administrative nightmare, with substantial delays likely. Brokage arrangements might mitigate these problems but the task would remain a formidable one. It appears that an acceptable response to an emergency situation may not be possible under the contract carrier plan.

**Conclusions**

The adoption of contract carriage may not be the best answer to the problem of inflation in the natural gas pipeline industry. The proposal creates serious potential costs relative to the economic benefits of lower prices and greater employment. It is true that allowing some industrial users or distribution companies to buy directly from the producers would lower their costs and, in the case of industrial buyers, prevent them from moving to alternative fuels. And it is true that the monopoly power of the pipelines would be reduced, which may be a plus. However, it should be pointed out that this solution yields only short-run benefits. I cannot see any superior argument to support contract carriage over the present regulatory arrangement once the dead-end of the past expensive contracts negotiated under the shortages of the 1970s become history. I feel that gas brokers would have fallen all over themselves to sign high priced contracts in the 1970s in the same way the pipeline companies did. Lower prices are always superior to higher ones, but lower prices are not necessarily the characteristic of common carriage. One conclusion is that the pipeline industry is in a much better position to perform the merchant function with a regulatory oversight than to turn over the function to intermediaries or brokers. The distribution companies' major goal is not to be responsible for meeting their supply needs. What they want is more control over the prices paid by one pipeline company at one delivery point, and it then is required to satisfy the exchange balance by deliveries back to the original pipeline company or one of its customers, usually at a different geographical point. These exchange amounts must balance over a certain period. It seems to me that there would be no need for exchange gas under contract carriage. Where there might be a social loss is in the disappo.. An incentive for the pipeline companies to minimize transportation miles through interconnection. From 1975 through 1980, the pipeline industry's volume of exchange gas rose 69 percent, from 3.6 Tcf to 6.1 Tcf. Given the volume of exchange gas should be concerned about the implications of its disappearance under contract carriage.

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is not feasible whenever provisioning or curtailment is necessary. Congestion of the pipeline network as well as the problem of the distribution of scarce supplies will be more difficult to deal with under this proposal. Next to the merchant function problem, this issue may be the most significant potential cost associate with the recommendation.

The rise of gas brokerage is not the way to reduce transaction costs. Enforcing costs on by-pass restrictions and the loss of flexibility by endusers are two areas where transactions costs are likely to increase. Another concern could be raised about the loss of "exchange" gas, which will inflate the transportation roles for which the distribution companies can be charged.

The history of transporting gas for other accounts indicates that the rate structure adopted under contract carriage would be insensitive to peak usage or capacity costs. Finally, a gas emergency would be harder to handle. The policy conclusion that comes out of this paper is that deregulation of the pipeline segment or making them contract carriers is not in the public interest. In this case, it will increase the cost of natural gas to the consumer in the long run. Short-run expediency to by-pass the expensive field contracts does not support a fundamental structural change in the way we should regulate the gas industry.

**Notes**

2. Ibid.
4. Although this is true for the industry in general, this may not be the case for larger fields in Texas and Louisiana.
6. Department of Energy, Statistics of Interstate Natural Gas Pipeline Companies, 1980 and 1975; Gas Accounts Sections, p. 6-2 and 6034, respectively.
7. Of course, one must point out that this benefit could be viewed as a cost of contract carriage status when

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The merits (or demerits) of mandatory carriage have been widely debated in a number of forums. Substantial attention has been devoted to the potential effects of mandatory carriage on pipelines, distributors, and end-users (both residential and industrial). Yet, little has been said or written about the effects of mandatory carriage on gas supply contracts in general, or on pipeline/producer contracts in particular. In large part, this oversight has occurred because there is great uncertainty about what future gas supply contracts will look like in the absence of mandatory carriage. In addition, there is substantial uncertainty about how pipeline regulation will evolve, absent legislation imposing mandatory carriage. In this paper, I offer some preliminary thoughts on possible futures for the interstate pipeline industry and consider the consequences of these futures for gas supply contracting. First, however, I will review the current gas market and supply contract situation.

Note: The views presented here are those of the author and do not represent official positions of the Interstate Natural Gas Association of America.
The Current Market and Supply Contracts

Since the NGPA was passed in 1978, the interstate gas market has changed from a preoccupation with supply to a preoccupation with demand. The gas market has gone from shortage to surplus in just five years. INGAA estimates that the current interstate surplus is between 2.5 and 3.5 Tcf. Interstate sales for resale declined 10 percent from 1981 to 1982 and an additional 18 percent in 1983 (year to date). While a portion of the 1983 demand loss was due to abnormally warm weather (December, January, and February were 9 percent warmer than normal in winter 1982-1983), permanent conservation due to the transition from low regulated wellhead prices has played a significant role in reducing gas demand. Analysts have also speculated on the effect on gas demand of fuel switching to oil and the recession. My belief is that fuel switching peaked in the first quarter of 1983 and has declined substantially since then as pipelines took a wide variety of actions to reduce gas costs. The key questions with respect to the recession are how much the gas-intensive industries will come back as the economy recovers and how much conservation investments by these industries will reduce their gas use. Preliminary work by INGAA suggests that the recession affects 1983 gas demand by about 5-10 percent.

In a period of declining demand and a growing surplus, one would normally expect prices to fall to the point at which supply and demand balance. The question of why gas prices did not fall in early 1983 was a major focus of debate over natural gas legislation this past year. Indeed, residential prices rose 26 percent in winter 1983 (December, January, and February) over the previous year. Inflexible natural gas supply contracts were blamed for the continuing price increases in the face of a supply surplus. In addition, some observers argued that the fact that pipelines were not required to carry gas for others contributed to the price increases. The advocates of "mandatory carriage" (as required carriers became known) believed that pipelines were shifting in cheap gas and taking more expensive gas. They argued that prices would fall dramatically if pipelines were forced to carry this cheap gas for others.

Recent evidence suggests that the 1982 mix of gas supply was skewed toward high cost gas; in 1982, tight sands gas (priced at $5.85/Mcf) was taken at a rate 11 percent higher than the take rate for cheaper old gas (priced at $3.98/Mcf; see Table 1). Pipeline take strategies were driven in large part by take-or-pay minimums in existing contracts. These minimums tend to be higher for contracts signed when pipelines believed they were likely to be short on gas. For example, take-or-pay minimums in 1980 (as a percentage of deliverability) averaged 60 percent for pre-1973 contracts, ranged between 80-95 percent for 1973-1979 contracts, and declined below 60 percent after 1979.

More recent evidence suggests that pipelines are no longer taking high cost gas disproportionately. By 1983, pipelines shifted to essentially a pro-rata policy across all cost categories (see Table 1). However, averages take as a percentage of deliverability declined precipitously from 81 percent in 1982 to 65 percent in 1983. Throughout 1983 pipelines negotiated vigorously with producers to reduce prepayment liabilities which arose from the failure to take gas at the minimum contract levels.

In addition, by fall 1983 it became apparent that wellhead prices were leveling off or declining. A survey by the House Subcommittee on Coal and Synthetic Fuels projected that prices at all levels of the interstate market (wellhead, city gate and end-user) would be essentially flat from spring 1983 to spring 1984.

<table>
<thead>
<tr>
<th>Gas category</th>
<th>1982</th>
<th>1983</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Take level (percent)</td>
<td>Price ($/Mcf)</td>
</tr>
<tr>
<td>Old gas</td>
<td>79</td>
<td>64</td>
</tr>
<tr>
<td>New gas</td>
<td>82</td>
<td>67</td>
</tr>
<tr>
<td>Deregulated gas</td>
<td>63</td>
<td>62</td>
</tr>
<tr>
<td>Tight sands gas</td>
<td>90</td>
<td>67</td>
</tr>
<tr>
<td>Other gas</td>
<td>79</td>
<td>64</td>
</tr>
<tr>
<td>All gas</td>
<td>81</td>
<td>65</td>
</tr>
</tbody>
</table>


bPercentage of deliverability.
In addition to the volume inflexibility caused by high take-or-pay minimums, existing supply contracts also tend to be inflexible with respect to price. In 1980, almost 60 percent of supply contracts covering post-NEPA wells had oil parity clauses or most-favored-nation clauses without market-out or had a highest regulated rate provision, an additional 14 percent had other indefinite price escalator clauses (which contemplate only price increases). Only 10 percent had market-out clauses, which allow the pipeline to lower the price if the gas is not marketable. The producer is generally given the right to break the contract if the pipeline's price is considered too low. The numerous escalator provisions which push prices upward prevent prices from falling quickly in response to changes in market conditions. These same pricing provisions facilitate price increases.

Despite this downward price inflexibility in existing contracts, there is substantial evidence of increasing use of market-out provisions in newer contracts. In a survey of offshore contracts, ENA found that 85 percent of new contracts in 1982 contained market-outs, up from only 36 percent in 1981. An INGAA survey showed that 98 percent of new gas supplies contracted for by interstate pipelines in the second half of 1982 contained market-outs. The effect of a market-out is to make a long-term contract a short-term contract because the producer can walk away if market-out price is too low. The transaction cost of finding a new buyer may make this as much a threat as a frequent occurrence. In the second half of 1982, market-outs had been exercised in more than 3,000 contracts. The producer cancelled the contract in a very small number of cases; the pipeline lost the gas for only five of the contracts, covering 2 percent of the reserves. Many pipelines have simply ceased contracting for new supplies until they can get their take-or-pay problem under control, the combination of surplus deliverability (with attendant high take-or-pay levels) and dramatic demand reductions means that some pipelines will be spending most of their time trying to renegotiate existing contracts rather than negotiating for new supplies.

A key question in pipeline ability to renegotiate existing contracts is the extent to which pipelines can persuade producers that the producer has something to gain from the new arrangement. Since both prices and take-or-pay levels are already too high, pipelines have attempted to offer producers greater market share through various special transportation programs. Two of these—by Transco and Columbia—are already allowed by the FERC. The debate over these programs is indicative of the key decision regulators face: To what extent will gas compete not only with alternative fuels, but also with gas?
competition, pipelines with high cost gas and excess deliverability will lose market share to pipelines with low costs. In addition, pipelines with lower cost gas and stronger markets will be able to return to gas purchasing more quickly than other pipelines. Because the overall market will be soft, pipelines which can contract for gas over the next several years will be able to obtain advantageous contracts; attractive reserves, pricing provisions which favor the buyer, and relatively low take levels. These contracts will enhance their competitive edge over time.

To the extent that the FERC encourages gas-on-gas competition, pipelines will be more successful in renegotiating inflexible contracts because producers will see the immediate gain in market share. Even if they lose on price, producers which renegotiate will gain on volume. Conversely, producers which do not renegotiate will lose sales even more. The traditional public utility concepts of regulation will need to evolve to accommodate notions of how and what to regulate if the FERC seeks to facilitate, rather than constrain, gas-on-gas competition. It is essential that the FERC develop a consistent concept of how to achieve a fair allocation and recovery of fixed costs. The debate over whether pipeline efforts to compete (either with oil or gas) are causing subsidies of one class of customers or another has already begun. These are not easy problems, and they are not the subject of this paper.

Over the longer run the backlog of existing contracts provides both buyer and seller with a reasonable amount of security (pipeline as to supply; producer as to cash flow). Both will be looking at the margin. Because of the uncertainty over what future markets will look like, most contracts will contain frequent price redetermination clauses and market-out provisions.

Over time, both buyer and seller will be looking for a portfolio of gas-based contracts [long-term reserve commitments, relatively assured take levels]; intermediate load contracts (medium term or minimal reserve commitments); and spot load contracts (no reserve commitment, short-term or spot sales either for specific quantities of gas or for very variable take levels).

The mix will vary from company to company, but FERC regulations and the type of producer will heavily influence the mix. For example, one might expect the FERC to reduce its notion of what kind of reserve life a pipeline should keep in the future. The concept of a twenty-year reserve life was developed when gas was cheap: what was expensive was the pipe. The financial community and the commission wanted to make sure that there was enough gas "behind the pipe" so that there would be enough gas to fill the pipeline to justify the investment. Now we have the reverse: Pipeline costs are largely sunk (interstate transmission charges average $3.70/MMBtu), but gas supply is expensive (the average wellhead value is roughly $3.00/MMBtu today). When gas was cheap relative to the cost of the pipes, it made sense to prove up twenty years of reserves in advance. Now that the cost of proving up gas is more expensive, we need to reconsider the consumer costs of proving up reserves in advance.

Today, there are still FERC regulations on the books requiring a ten-year reserve life for interstate pipelines. On a net present value basis, reserves which will be produced over a ten-year period will cost more than the same volume of reserves produced in five years. The producer will charge a higher price for a ten-year production profile than for a five-year profile because the net present value of the reserves is lower. The slower is the production rate (assuming for the moment that no resources are lost from the faster drawdown rate). In essence, to obtain a high reserve life, pipelines will have to pay producers to keep gas in the ground. This "storage" or insurance cost will be passed on to consumers. The storage costs associated with a ten-year reserve life may have become too expensive in a wellhead decontrolled world.

The cost of obtaining various components of this portfolio will vary. Contracts calling for slower production of reserves are likely to be more expensive than those calling for faster production rates. Contracts with higher levels of guaranteed takes are likely to be less expensive than contracts with variable or low rates of take. [If the producer is given the uncertainty associated with varying demand, he will charge for taking on this risk.] Long-term contracts will provide more assured cash flow to producers and hence should be less expensive than shorter term contracts (at the same take levels). Short-term contracts give producers the risk of marketability. Independent producers may bargain for higher take rates (and lower prices) because guaranteed cash flow may be more important to their financing needs than for majors (who tend to finance internally). Majors, who can enormously, may play more in the short-term spot market. But both buyers and sellers are likely to be looking for a portfolio of contract instruments.

The difficult problem for regulators under the status quo is how to provide the regulated entity (pipeline or distributor) with enough pricing flexibility to compete with fluctuating alternative fuel prices and lower priced gas. Under the traditional system, regulators may still require some kind of reserve life for the "public utility" portion of the load. For these types of relatively inelastic users, the costs of conversion to other sources of energy is relatively high, and the distribution company has considerable monopoly power. Because this load is weather-sensitive, pipelines would supply gas based on a combination of variable-
take contracts with producers and storage and winter peak supply contracts. The more price-elastic portion of the load (industrial and electric utility boiler users) may evolve into a more competitive type of service. Regulators could allocate fixed costs to this load (just as costs are allocated between jurisdictional and nonjurisdictional sales today), but sellers would have the flexibility to price to meet the rapidly changing competition. In some cases, pipelines would provide only transportation service, and brokers or end-users would supply gas. In other cases, pipelines would supply both gas and transportation. But sales to these customers would be open to competition.

The supply contracts which would emerge from this competitive process would vary with the customer. The tendency would be for two kinds of contracts to emerge. (1) Direct end-user contracts would tend to be based on netback pricing; the buyer would want to ensure that prices were competitive with alternative fuels. The risk of changes in oil prices would fall on the producer. (2) Brokers would buy gas on a short-term, fixed-price basis. Their success or failure would lie in their ability to move promptly in the market and to change prices quickly enough to respond to end-use market changes. Thus, even under traditional regulation, we can expect to see considerable changes in gas supply contracting in the future.

**What is Mandatory Carriage?**

Mandatory carriage is a proposed regulatory system which superimposes a common carriage obligation on top of the public service obligation embodied in the Natural Gas Act. Under this "mixed" system, pipelines would be required to carry gas for others where access capacity was available. The proposals generally have five key features.

- **Cost Reimbursement.** The system would give access capacity to all customers who requested it, subject to limitations on the amount of gas that could be transported.
- **Optimism in Capacity.** The system would be designed to permit the development of new capacity in response to changes in market conditions.
- **Incentive for Expansion.** The system would provide incentives for pipeline companies to expand their capacity in order to attract new customers.
- **Consumer Protection.** The system would provide protections against abuse of market power by pipeline companies.
- **Administrative Flexibility.** The system would be flexible enough to allow for changes in circumstances over time.

The main criticism of mandatory carriage is that it would result in higher costs for consumers. However, proponents argue that it would provide customers with greater flexibility and control over their gas supplies. The debate over mandatory carriage continues, with both proponents and opponents expressing concerns about its potential impact on the gas market.
renegotiation is essential to make gas prices fully responsive to demand changes. In particular, contracts need to provide greater downward price flexibility during periods of gas surplus. Recent trends in new contracting provide evidence of increased use of market-out provisions which provide this type of flexibility.

Regulatory decisions by the FERC will have a profound effect on the pace of contract renegotiation. If the FERC encourages gas-on-gas competition, producers who fail to renegotiate high price, high take contracts will lose market share. Thus, gas-on-gas competition focuses market pressure on recalcitrant producers. Conversely, if the FERC constrains competition, producers will have less reason to renegotiate. Producer market share, and hence producer cash flow, will be less dependent on getting gas prices down to market-clearing levels if core markets are protected.

Future contracts will also be affected by the pace of contract renegotiation. Over time, pipelines (and many producers) will seek a portfolio of supply contracts. The pipeline will seek to balance security of supply with both price and cash flow. Over time, the FERC and the pipelines are likely to reconsider the value of a ten-year reserve life as a gas contracting goal.

Mandatory carriage, as currently proposed in Congress, will also slow the pace of contract renegotiation. By giving pipeline customers the option to “go direct,” mandatory carriage reduces pipeline leverage with producers. If pipelines cannot offer producers enhanced market share in return for contract concessions, producers are less likely to modify the contract to make it more market responsive. In the longer run, mandatory carriage is likely to increase system supply costs to pipelines and their supply customers by increasing the variability and uncertainty of demand for system supply.

Notes
1. Interstate Natural Gas Association of America, "The Gas Contracts Problem: Results of an INGAA Survey," B&P-1, May 1983, p. 10. The 3.5 Tcf estimate is for the 10 percent lower demand case.
2. Energy Information Administration, Natural Gas Monthly, October 1983, p. 29.
11. Ibid., p. 1.
13. Ibid., p. 15. Some caution must be exercised in interpreting these figures, however, since the average market-out price was $4.50/Mcf, well above most estimates of a "free market" price of roughly $3.00/Mcf.
14. See December 2, 1983, petition to the FERC for rulemaking on "discrimination" in rates and brokering programs by three industrial groups. (Progress Gas Consumers et al.) Docket RM84-5-000.
15. For examples of mandatory contract carriage, see Title IV of S.715, which was reported to the Full Senate "without recommendation" and defeated on a floor vote of 28 to 67; see also Title IV of the Shelby/Corcoran bill, which was reported to the Full House Energy and Commerce Committee by a one-vote margin. For a general review of mandatory contract carriage, see INGAA, "Natural Gas Carrier Status During the Current Transition: A Critique of Mandatory Contract Carriage," B&P-1, January 1984.
16. A notable exception is the recent modification in Senator Bradley’s substitute to S.715 which uses current pipeline contracts and certificates to measure "available capacity." See Federal Register, November 6, 1983, pp. 15701-15706.
17. A key problem with many proposals is that this adjustment
in contract and service obligations is insufficient to protect a pipeline from being caught between the old public utility obligations and contracts and the new mandatory carriage requirements.

COMMENTS

Stanley V. Ballis

Curtis Cramer and Catherine Abbott voiced opposition to the imposition of common or contract carrier status on natural gas pipelines. They not only concluded that contract carriage is not the solution for the current serious problems facing the natural gas industry, but also correctly recognized that contract carriage would only exacerbate those problems and create yet additional negative effects on interstate pipelines, distributors, and the locked-in consumers that will continue to be served by the pipelines and distributors. Rather than repeat the various points made in opposition to contract carriage, with which I am in general agreement, I would simply add a few comments from the perspective of the small, municipally owned distribution systems and the small, residential consumers that I represent as to the especially egregious injury that contract carriage would cause to the "little guys." Contract carriage may provide short-term lower prices for high load factor, large purchasers of natural gas, but many distributors and locked-in residential consumers are too small and have too low a load factor in most cases to be able to purchase directly from producers. Thus, combiner of purchasers are necessary in order to include a large enough and diversified enough load, such that significant quantities of gas can be purchased from producers on a year-round basis at a levelized, high load factor. Interstate pipelines fill that very role. Hence, the problem is not having interstate pipelines purchasing gas from producers and reselling it to distributors, but
Instead it is policies set forth in statutes, such as the Natural Gas Policy Act of 1978 (NPGA), and in the decisions of the FERC which discourage the interstate pipelines from exhibiting the normal behavior that would be attributed to purchasers to undertake all actions to keep down their cost of purchased gas. If pipelines would use their market power as purchasers to bargain at arm's length on behalf of all of their customers, then, in the context of the anticompetitive natural gas industry that exists today (see my comments in the previous section), this is the optimum arrangement to protect small distributors and residential consumers.

A number of bills have been introduced in Congress regarding contract carriage, many of which permit end-users to obtain gas supply directly from producers and then obtain mandatory transportation of that gas by interstate pipelines. The result of these bills would be to permit large industrial end-users to obtain short-term gas supply at discount prices, while providing no price relief for the locked-in customers of the pipeline system.

In fact, in the long term, the price for all gas supply will increase as a result of intermarket competition. The concept of "competition" that Adam Smith envisioned for a free market is not the contract carriage "competition" of many purchasers competing to obtain the same available gas supply. While there may be more keen "competition" when twenty dogs fight for one bone than when two dogs vie for that same bone, this type of "competition" in the gas industry can only result in higher prices as the additional competitors bid up the cost of the available gas supply.

Moreover, when a storage of capacity occurs on the pipeline system, a number of these bills would not give a preference to existing sales customers of the interstate pipeline to utilize the capacity, but would give equal and perhaps superior access to that capacity to the mandatory contract carriage customers, under the basis of the priorities set forth in Title IV of the NPGA, and therefore, an existing nonpriority industrial end-user that has been served by a distribution company for twenty years would be cut out so that an industrial process user that began contract carriage yesterday can utilize the available capacity instead.

Of course, these large industrial end-users which intend to utilize contract carriage do not want to give up their right to obtain gas supply from their distribution systems and the interstate pipelines that serve those distributors should something go wrong with their new supply of gas contracted for directly. Accordingly, these industrial end-users want to be afforded nondiscriminatory treatment should they wish to return to the distribution system. Meanwhile, the interstate pipeline is supposed to obtain sufficient reserves to be able to meet the demands of the industrial users that have decided no longer to be sales customers in case they decide to go back to the future once again to become sales customers of distributors rather than contract carriage customers of the interstate pipeline.

While Abbott is opposed to the concept of contract carriage, he inconsistently favors an increase in gas-on-gas competition. That kind of competition is occurring through contract carriage programs approved by the FERC whereby pipeline A is willing to transport gas purchased in the field by a common customer that it shares with pipeline B, where the gas obtained by the customer and transported through pipeline A displaces a sale that would have been made by pipeline B.

This type of market raiding between pipelines for the benefit of partial requirements customers may be fine so long as the losing pipeline's additional unit fixed costs, including any increased take-or-pay prepayments, are borne solely by the losing pipeline's shareholders and not heaped upon its full requirements, locked-in customers who have no alternative supply of natural gas. In a competitive market, the losing pipeline would reduce its price, even if profits had to be reduced as a result, to recapture and increase loads. The losing pipeline would not have a locked-in market to ensure it against loss.

Abbott recognizes that full requirements, locked-in customers of a pipeline are required to subsidize the large industrial end-users which are able to participate in contract carriage programs of the various pipelines. However, he refuses to come to grips with this fundamental and fatal flaw in the contract carriage programs of interstate pipelines and gas-on-gas competition by simply stating that "these are not easy problems, but they are not the subject of this paper."

As Abbott recognizes, the problem is not a lack of contract carriage programs approved by the FERC or by Congress or the lack of gas-on-gas competition between interstate pipelines, it is simply that "both prices and take-or-pay levels are already too high" in producer-pipeline gas purchase contracts. But there is no valid reason these prices and take-or-pay requirements should be "too high."

The producers and pipelines have been free to agree to any price for new gas supplies under Section 102 of the NPGA, so long as the price did not exceed the maximum lawful price, which today is above the level of the No. 6 fuel oil price. Yet pipelines agreed in virtually every situation to the maximum lawful price. As far as deregulated Section 102 gas is concerned, the producers and pipelines have been free to bargain at arm's length, but the pipelines inevitably agreed to prices far above the market-clearing level and in most cases above the price of No. 2 fuel oil, even though they had to resell the gas to end-users utilizing No. 6 fuel
oil as an alternate fuel. Take-or-pay requirements and other nonprice terms in contracts between producers and pipelines were not regulated by the NPGA, and therefore, the interstate pipelines could have bargained freely on behalf of their customers for reasonable terms that would not have resulted in the present anomalous situation of pipelines taking the most expensive gas because of the highest take-or-pay requirements and shutting in the lowest price, flowing gas.

In conclusion, there can be no question that the natural gas market is in need of strict price and production controls in the absence of the break up of the anticompetitive structure of the natural gas industry. It is not in need of congressionally or FERC-approved contract carriage programs.

COMPMENTS

William K. McCrackin

The natural gas industry today is once again in a state of transition. In a relatively short time the gas industry has moved from expansion to supply shortages, and most recently to market contraction. Currently, the gas industry is operating contrary to traditional economic principles. Although a surplus of gas exists, gas prices remain high. Moreover, in most businesses, a purchaser requiring a greater volume of goods purchased those goods at a lower unit price and on more favorable terms than a smaller volume purchaser. Theoretically, pooling the demands of numerous buyers should result in a price lower than an individual buyer would be able to obtain independently. Such should be the case with gas pipelines, which basically provide a transportation network and acquire gas to serve numerous customers having varying delivery requirements. This, however, is not the case today. End-users are now able to purchase gas directly from producers at prices less than those charged by their traditional supply source.

The facts are clear: Pipelines are no longer providing the services for which they were intended. That is not to say they are not delivering gas, as was the case during the curtailment years, but they are not delivering gas at a price that is marketable.

A number of factors have created this anomalous condition. The Natural Gas Policy Act of 1978 (NPGA) was enacted to, among other things, reduce the imbalance of supply and demand that existed at the time by establishing incentive prices
under Title I. Pipelines, reacting to past curtailment and
no doubt mindful of the regulatory environment that virtually
guaranteed recovery of purchased gas costs, developed the
attitude that gas reserves had to be obtained at any cost. Thus,
payment of NGPA ceiling prices became the rule rather than
the exception. In addition, gas purchase contracts
between pipelines and producers included excessive producer
protection provisions, such as area rate clauses, indefinite
price escalator clauses, and high take-or-pay volume
requirements.

Higher gas prices, combined with federal and state legis-
lation designed to promote conservation, declining fuel oil
prices, customer reactions to prior years’ curtailments,
and a recessionary economy, all contributed to the decline
in the demand for natural gas. Yet, despite the market
decline, prices remain at high levels largely due to the
long-term contracts between pipelines and producers.

It can only be expected that demand will continue to
diminish unless the price of gas is reduced to marketable
levels. It is essential for pipelines and producers to realize
that unless their prices are market responsive, their gas
will not be purchased.

Since all gas costs, not in excess of maximum NGPA prices,
generally receive favorable rate treatment, pipelines do
not currently have an incentive aggressively to negotiate
price and take-or-pay reductions with their producers. Pipe-
lines have virtually no financial risk associated with their
gas purchase decisions. Actual gas costs are generally passed
on to customers automatically through periodic purchased
gas adjustment clauses (PGAC). Moreover, gas purchases or take-or-pay
expenditures have traditionally received full rate base treat-
ment which even allows the pipeline to earn a profit on the
amount of its gas prepayments (that is, the pipeline
earns at the overall rate of return which includes a return
on equity). Even if markets diminish, the pipeline is likely
to file for a rate increase based on lower sales levels,
resulting in yet higher rates and possibly further market
erosion.

Obviously, changes are required. Unfortunately, there
are no quick fixes acceptable to all segments of the industry.
Gas markets have changed. All end-users are conserving energy,
alternate fuel prices have fallen, industrial thinking and
personal life-styles have changed, and the efficiencies of cost cutting
have become key to survival and profitability.

These same criteria must be pursued by the natural gas
industry. Steps must be taken to reduce the price of gas
at the burner-tip. The largest component of the burner-tip
price is, of course, the wellhead price. As an example, of
Michigan Consolidated average rate charged
to industrial customers in 1983, almost 60 percent represents
wellhead costs. Since 1975, the wellhead component has
increased more than 600 percent.

Policies and practices of the past no longer produce the
results necessary to promote efficient service at just
and reasonable rates. The mentality of the industry must
change. Risk must be introduced to pipelines, and pressure
must be placed on wellhead prices.

Pipelines are the only segment of the industry which have
not had to bear the financial risks associated with
management decisions. Even during curtailment, pipelines
were protected from the risk of shortage of supply by the
actions of the FERC and are now being insulated from declining
markets. Unlike pipelines, distribution companies do not have
gas cost minimum bills with their customers. Monthly
service charges are minimal, and customers have the ability
to leave the system at any time without bearing any future
obligations. In Michigan, the PCA has been eliminated.
Distributors in Michigan are now required to file gas cost
recovery plans which include a review of their gas purchasing
practices by the Michigan Public Service Commission and
consumer groups. The responsibility for imprudent gas acquisi-
tion practices is borne by the distributor’s stockholders.

Rate design changes must be implemented at the pipeline
level. A modified fixed/variable form of rate design that
places return on equity (and associated income taxes) in
the commodity rate, and thus at risk, will help create the
pressure necessary for pipelines to realign their actions
with the demands of the marketplace. Under this type of
rate design, pipelines will not earn their authorized rate
of return unless their gas is priced at marketable levels.
This will, in turn, return on equity, would be earned
only when the pipeline fulfills its service obligation by
efficiently utilizing its capacity, minimizing gas costs,
and thus maximizing sales.

Gas cost minimum bills must be eliminated so that
companies with multiple supply sources can purchase the lowest
priced gas available and minimize costs to their customers.
This will send a direct price signal to the high cost pipelines
that its gas is priced too high and it must take positive
actions to reduce that price in order to maintain and regain
sales.

Mandatory contract carriage may be another means of
creating pressure on wellhead prices. Under voluntary contract
law, pipelines maintain control over their markets.
In a pipeline has the ability to determine whether it will
provide a service, it is unlikely to provide that service
unless it will benefit from the transaction. Only minimal
positive overall change can be expected under these conditions.

The special marketing programs developed recently can
only be viewed as a short-term response to the dilemma of
pipelines’ high gas prepayment levels and/or loss of industrial
markets to alternate fuels. A permanent reduction in the
overall price of gas to all customers should be the goal of regulatory change.

The goals of mandatory contract carriage should be the promotion of competition, reduction of wellhead prices, and an increase in overall sales. In order for these goals to be attained, full transportation and distribution costs must be charged on these services. After reducing the burner-tip price by the transportation and distribution charge, the remaining amount will represent what the customer is willing to pay to the producer and will reflect the true value the end-user places on the gas. Obviously, for an end-user to contract directly with a producer and not purchase from its traditional sources, it must determine that the new service is either superior or more likely less expensive.

The cost savings must result from wellhead price reductions and not from discounting transportation and distribution charges. Any artificial price differential resulting from discounting pipeline and distributor rates cannot be permitted. Such action would result in higher rather than lower wellhead prices and would shift costs [the amount of the discount] to other customers who would continue to purchase gas from the traditional supplier. Any end-user receiving a discounted transportation and/or distribution rate would have a competitive advantage over any other potential buyer of gas who bore full transportation and distribution costs. This would result in the end-user receiving the discount having a greater amount available to be paid at the wellhead, after the netting back process. False market signals would be sent to the producer, and most likely the price required to be paid by all gas buyers would increase. This must not be the result of mandatory contract carriage.

Through a combination of rate design changes, the elimination of gas cost minimum bills, and mandatory contract carriage, pipelines will be forced to become responsive to the market, aggressively renegotiate contracts with producers, and alter their gas purchasing practices so that a lower overall cost of gas can be achieved which will benefit all end-users. Pipelines would then bear the risks as well as earn the rewards of management decisions.

Notes
1. On May 25, 1984, the FERC issued Order No. 380, which requires the elimination of variable cost minimum bill provisions from pipeline tariffs. The rulemaking is scheduled to become effective on July 31, 1984.
2. See note 1.

In recent months there has been extensive legislative activity concerning natural gas. On most issues addressed in the various legislative proposals there has been widespread disagreement. However, on one issue there appears to be a unanimity of opinion. Where surplus pipeline capacity exists, it should be used to provide transportation service. In my view, this emphasis on mandatory carriage is an outgrowth of problems that occurred in the 1970s, when both producers and end-users sought to have gas transported by interstate pipelines to offset curtailments. It was frequently difficult for this transportation to be arranged, and many pipelines refused to provide any short-term transportation service. Therefore, it is not surprising that many producers, end-users, and distributors feel that some type of mandatory carriage will be necessary when gas is deregulated and there are many buyers competing for the supplies. Also, the emphasis on mandatory carriage undoubtedly reflects a recognition of the statutory limitations currently imposed on the FERC. The commission cannot require that pipelines provide transportation service; its authority is limited to approving or disapproving transportation proposals by the pipelines or imposing economic sanctions where it finds the companies guilty of imprudent actions. However, none of these authorities enable it to mandate transportation service.

While the FERC cannot mandate transportation, it can influence the willingness of interstate pipelines to provide voluntary transportation. One of the ways the commission
can encourage the use of pipeline capacity for transportation. This is to establish programs that minimize the amount of regulatory oversight. Over the years, the commission has adopted many such programs. For example, in the mid-1970s, the Order No. 533 program was instituted to encourage pipelines to transport gas for high-priority projects, feedstock, and plant protection uses. This program enabled many facilities to continue operations during the period of natural gas cutbacks. It was subsequently continued under FERC Order No. 2, issued in 1978. In 1979 the commission instituted a number of additional programs designed to encourage transportation for such diverse uses as essential agriculture, schools, hospitals, and even fuel oil displacement. That same year the commission issued Part 284 of its regulations, which implemented Title III of the Natural Gas Policy Act. Part 284 enabled both interstate and intrastate pipelines to provide transportation service without being subject to the limitations of the Natural Gas Act. Consequently, it was possible for the surplus intrastate supplies to be made available to the supply-deficient interstate market. In July 1981 the commission issued its Order No. 92 program, which permitted the transportation of CEGs gas owned by distribution companies. These programs made it possible for natural gas to be transported for essentially all end-use categories. However, each of these transportation programs contained certain limitations that reduced their effectiveness. Consequently, in 1983, the commission adopted a Blanket Certificate Program designed, inter alia, further to encourage the use of pipeline capacity for transportation service in its Order Nos. 319 and 234-B, the commission incorporated and expanded the previous programs. Particularly important, the scope of its Blanket Certificate Program was expanded to permit the use of the pipeline capacity to transport natural gas for low priority non-fuel use. This latter program is being conducted on an experimental basis and will end on June 30, 1985. To encourage pipelines to provide transportation service for low priority uses, the commission permitted an Additional Incentive Charge of up to 5 cents per million British thermal units. This additional allowance would be retained by a transporting pipeline or pipelines. Although not all of the commission’s transportation programs will be in place for the full year, it is estimated that more than 6.0 Tcf of natural gas will be transported by interstate pipelines during 1983. This is a significant portion of the total amount of natural gas that will be marketed in 1983.

The commission’s transportation programs have sometimes been criticized as not providing sufficient economic incentives for the pipelines to use their capacity for transportation purposes. In order to understand the evolution of the commission’s approach toward economic incentives, it is necessary to consider the circumstances that existed during the gas shortage in the 1970s. During that period, although the pipelines were unable to meet the full contractual entitlements of their customers, they nevertheless sought to recover their costs and earn a reasonable return on all of their investment dedicated to jurisdictional natural gas service. The commission was generally sympathetic with the difficulties being encountered by the pipelines and permitted them to earn returns even on those facilities not being fully utilized. Consequently, when the commission adopted its program of encouraging the use of pipeline capacity to provide transportation service, it appeared reasonable that any revenues achieved therefrom should accrue to the benefit of the pipeline’s customers who were otherwise paying the costs of unused capacity. Therefore, the commission adopted the approach of requiring the crediting of revenues in excess of out-of-pocket costs. This approach was followed until the passage of the NGPA.

In implementing Title III of the NGPA, the commission elected to afford pipelines two options: (1) They could establish representative levels of transportation volumes or revenues for purposes of establishing rate levels, or (2) They could credit transportation revenues in excess of out-of-pocket costs. If a pipeline elected the first option, there were two types of economic incentives involved: (1) The pipeline had the incentive to achieve at least that level of transportation or revenues, and (2) to the extent the pipeline could exceed those levels, it could improve its earnings situation. One purpose of the commission’s approach was to encourage pipelines to set transportation goals and then attempt to exceed them. Another purpose was to make pipelines reasonably indifferent as to whether they sold or transported the gas. However, it was generally recognized that for many companies it was difficult, if not impossible, to achieve a point of indifference simply because the pipelines’ sales rates recovered more than transmission costs. There have been claims of ambiguity concerning the specific language under Part 284 as it pertains to revenue treatment, but the commission made its intent clear in Order No. 319. The commission has an obligation to the pipelines and their customers to assure that the rates charged are just and reasonable. The commission has attempted to achieve a reasonable balance between providing the necessary economic incentives to the pipelines to provide transportation service and assuring that their customers are not required to absorb unreasonable costs as the result of the transportation.

Just as the FERC has been criticized for not providing sufficient economic incentives for transportation service, so, too, has it been criticized for limiting the use for which gas can be transported, particularly under the Special Marketing Programs. The commission has recently addressed
the SMPs of certain pipelines and two producer groups. In
approving these programs, including the transportation of
gas thereunder, the commission required their availability
to those markets which might not otherwise use natural gas
or would use it only under special price concessions. In
other words, the programs would result in an increase in
natural gas consumption which would benefit all customers
and classes of consumers regardless of whether they actually
received the lower priced gas. The commission's orders spelled
out why it felt it could justify this limited application
of the programs. The orders also specified why the commission
did not feel it had the necessary information to quantify
the effect of gas for gas competition, particularly for the
so-called core markets. The commission adopted a monitoring
activity to determine the effects of the SMPs on the recipients
of the gas and on those who are ineligible to receive the
gas. The final word has not been spoken on these programs,
and some additional markets may be available in the future.
The commission has had and continues to have an effective
transportation program. This is demonstrated both by the
number of programs in place and by the volumes of natural
gas being transported under the programs. As pointed out
earlier, more than 5.0 Tcf of natural gas is expected to
be transported by interstate pipelines in 1983; this represents
an increase over prior years, and it is expected that transporta-
tion volumes will continue to increase. With deregulation
on January 1, 1985, it is expected that there will be added
emphasis on transportation service. It appears that the
pipelines are rapidly becoming transporters as well as sellers
of natural gas. Nevertheless, not everyone who desires trans-
portation will be able to make the necessary arrangements;
this will continue the push toward mandatory carriage.
However, as transportation becomes more available, the emphasis
on mandatory carriage should decline. Also, as supply and
demand become better balanced, there will be less emphasis
on mandatory carriage. Therefore, it appears that the need
for mandatory contract carriage may become a short-term
phenomenon and will become less important over time. Whether
or not legislation is enacted to require mandatory carriage,
the commission has in place programs which should permit
the vast majority of the gas to be moved under voluntary
arrangements. Other programs may also be implemented where
a need is demonstrated.

Notes
1. Order No. 539, issued August 28, 1975 (54 FPC 821);
   Order No. 539-A, issued November 10, 1975 (54 FPC 2058).
Part Eleven:
*International Issues in Natural Gas Pricing*
It is a convention to start discussion of U.S.-Canadian relationships with a reference to the longest undefended border in the world. I am going to begin by pointing out that Canada and the United States enjoy one of the world’s largest and oldest international energy trade relationships. Natural gas has been its principal component for nearly a decade. Since the early 1980s, Canadian gas exports to the United States have grown from 10 bcf per year to the range of 700-1,000 bcf per year, which figure has obtained since 1970. I cannot think of any longer lasting contractual international relationship in the oil or gas area.

Perhaps one key to the proven, successful management of our bilateral trade has been a pragmatic mixture of enlightened self-interest leavened with accommodation, compromise, and--some might even suggest--capitulation, when necessary. Undoubtedly, both countries have benefited. On the Canadian side, gas reserves have been developed for and dedicated to the export market. This assurance of supply has been essential to the United States in building the consumer confidence needed for market development and indispensable to the financing of infrastructure to serve its market. In turn, the United States has been an equally secure source of foreign earnings for Canada from gas sales; these are expected to total close to $4 billion Canadian in 1983. Revenues from gas exports are used by the Canadian industry to continue and expand oil and gas exploration activities.
thus further lessening North American dependence on offshore imports.

Given these benefits, the skeptic might wonder why government management of the Canadian-U.S. gas trade, and specifically the pricing component, is required at all. The answer might be that the sensitivities inherent in any buyer-seller relationship—the assurance that one is, in fact, getting a good deal—are heightened when an international boundary is crossed, when a strategic energy commodity is being traded, and when the exporter is also to a degree oil-import dependent.

The importing nation is naturally concerned that its citizens have access to a secure, competitively priced source of energy. The exporter will want to ensure that a fair price is returned to its producers. The management by governments of bilateral gas trade must balance these equally valid objectives.

For Canada, there are specific reasons for government involvement in natural gas pricing. As the resource owners, the producing provinces have jurisdiction over the natural gas reserves within their boundaries, while foreign trade is an exclusive responsibility of the government of Canada. Decisions on gas exports must take into account the interests of both levels of government as well as those of gas producers, pipeline companies, exporters, Canadian consumers, and of potential producing and exporting regions.

Those involved in overseeing public utilities will know that a regulator’s lot is not always a happy one. In times of national vulnerability, for example, rapidly rising energy prices coupled with supply shortages, government intervention is expected and even demanded by affected constituencies. As the danger passes, regulation becomes an obstacle to be removed as quickly as possible. It seems that public confidence in regulation is in proportion to the perceived risks and benefits arising from a free market.

With respect to Canadian-U.S. gas trade, government intervention and consequent regulation on both sides of the border may have a role to play in seeing that adjustments do not occur so abruptly as to undermine established, long-standing trade relationships. The challenge is to ensure that regulation truly and does not become an excuse either for abrogating commitment or for avoiding necessary adjustment.

Let me describe the Canadian regulatory framework. The history of government involvement in the Canadian gas industry has roughly paralleled that in the production of that industry. Regulations have gradually been introduced in response to specific problems arising from a changing market environment. For example, following the great Canadian debate of 1956 over the construction of what was to become the Trans-Canada Pipelines system, a royal commission, noting the extent and importance of Canada’s energy resources and potential problems with U.S. resources and markets, recommended establishment of a national energy authority. In response, the National Energy Board (NEB) was created in 1959 with responsibilities for licensing international trade in gas, oil, and electricity; the certification of international and interprovincial pipelines and international power lines; and the regulation of pipeline tariffs. As well, the board was to advise the government on the development and use of energy resources.

More specifically, the NEB may issue licenses for the export of natural gas, subject to the approval of Governor-in-Council, the Canadian federal cabinet. Under the original provisions of the NEB Act, the board was required to satisfy itself that the gas to be exported was surplus to reasonably foreseeable domestic requirements and that the export price was just and reasonable in relation to the public interest. Under a 1970 regulation made pursuant to the act, all natural gas export prices were subject to review by the NEB. Where, in the opinion of the board, there had been a significant increase in prices for competing gas supplies or for alternative energy sources, the board was required to report its findings and recommendations to the cabinet. The background to this change, which was made coincident with the approval of large additional gas export volumes, included the perception that the global era of “cheap energy” was ending.

Amendments to the NEB Act in 1982 removed specific references to pricing in the board’s assessment of export applications. Responsibility for making price recommendations to the cabinet devolved instead to the Minister of Energy. This reallocation of responsibilities reflected the fact that energy pricing in recent years had become the subject of government-to-government dealing, both within Canada and in international trade.

Within this regulatory framework, Canadian government intervention in export pricing has run the gamut from a relatively laissez-faire approach to the current practice of a government-prescribed price. In reviewing the policies that were adopted and adapted, it can be seen that genuine attempts have been made to balance the bilateral interests described earlier.

Prior to 1975, the natural gas export price was determined by contract between the buying and selling companies. NEB involvement in these early years was to monitor the contract selling prices to ensure that these were just and reasonable. Pricing formulas normally consisted of a base price with provision for modest annual escalation. It was a buyer’s market, characterized by low producer field prices and rapid expansion of pipeline systems, including those linking Canadian reserves to U.S. markets, such as the Alberta-California pipeline.
Indeed, prior to 1967, some Canadian gas was being sold in the export market at a price lower than that in a neighboring domestic market. This was one of the circumstances which led to establishment of the NEB. In response, the NEB introduced three price tests to be met by the export selling price in individual licenses. These were: (1) does it recover its appropriate share of the costs incurred by the Canadian transmission company? (2) is it not less than the price to Canadian customers of the transmission company in the general area of the proposed export, after allowance for variations in the terms of delivery? (3) does it result in prices in the U.S. market area close to the least-cost alternative for energy from indigenous sources? During the 1970s, the pendulum swing from a gas buyer’s to a seller’s market. Continued, regulated, low U.S. gas prices led to increased demand. At the same time, the United States was importing growing volumes of oil, much of it from insecure overseas sources.

In late 1974, based on its third price test—the cost of alternative fuels in the export market area—the NEB found Canadian gas exports to be underpriced. When it became apparent that the pricing provisions in existing export contracts were not responsive to a rapidly changing world energy market, the Board recommended that the export price be increased from the average prevailing price of Canadian $0.55/MMBtu to a uniform border price of Canadian $1.00/MMBtu effective January 1, 1975 (the change was made two months earlier for exports from British Columbia).

The primary determinant for establishing this price was a commodity value concept in which the price was equated with a weighted average burnout price of alternative fuels in the markets served. In calculating commodity value, the board gradually placed greater emphasis on the cost of imported, rather than price-controlled domestic, crude product. Implicit in this concept was a view that Canadian gas was a preferred substitute to insecure, increasingly expensive OPEC oil.

Because Canada also was a significant importer of OPEC oil during this period, the principle of backing off exports through use of a North American resource was consistent with our perspective of the public interest. In fact, the substitution value concept which linked the gas export price to the cost to Canada of all imports was formally introduced in 1977.

Obviously, the increases inherent in these approaches to export pricing were not accepted without reservation by the U.S. government or the NEB. A large part of this resistance was voiced by much discussion and debate between the two countries. Again, attempts were made to accommodate and compromise. In 1976, Canada proposed moving from a uniform to a variable border price, reflecting differences in alternative fuel prices in the various regional markets served. This proposal was dropped when the United States objected that differential pricing would extend Canadian jurisdiction beyond the international boundary and would be discriminatory. In 1979, the United States unsuccessfully sought a cap on the Canadian price equal to the border price of any other pipeline imports into the United States. We did, however, agree the following year to introduce a 90-day delay period between notification and implementation of price changes. The culmination of these discussions came with the March 1980 Canada-United States Understanding on Natural Gas Export Pricing, which formalized the substitution value concept, otherwise known as the Duncan-Lefond formula after the respective ministers of energy at the time. Because this formula has been both praised and vilified, it may be worthwhile to review how the policy has operated.

First, our export price is not set arbitrarily. It is based on the cost to Canada of crude oil imports, with consideration given to the cost of alternative fuels in the United States. It is predictable and, as evidenced in 1983, can go down as well as up.

Second, our price has been stable and consistently below full substitution value. Since 1980, there have been only three amendments to the price—two increases and one decrease. The border price has also been consistently below the ERI’s ten-city weighted index of fuel oil prices.

Third, the price applies at the international border; not at the point of production. It thus includes substantial gathering and transportation costs within Canada, in some cases in excess of U.S. $1.00/MMBtu.

Finally, although not implicit in the formula, the Canadian price can be said to include a premium for security of supply. The production contracts which underpin export licences are based on field reserves and not on deliverability contracts. This means that Canadian gas dedicated to the export market is produced at a lower rate over a longer period than is generally the case in the United States. Let me in this context note that Canadian gas reserves approximate 70 Tcf, compared to about 200 Tcf in the United States. However, Canadian reserves are being drawn down at the rate of only about 2.5 Tcf annually, compared to 18-19 Tcf in the United States, a difference in reserves-to-production ratio of 10:1 in the United States and 28:20:1 in Canada.

The fact remains that, just as the United States was the prime beneficiary during the early years of the bilateral trade, Canada took advantage of the opportunities provided by a seller’s market. We were helped in no small measure by the large cushion of low cost gas created by the Natural Gas Policy Act of 1978. It cannot be surprising that, in the international energy environment of the 1970s, Canadians would want to capture, while they could, a premium price
for the export of a nonrenewable natural resource.

The Netherlands, Europe's largest gas exporter, was able quickly to obtain much of the rents available from rising international oil prices during and after the first crude oil price run-up of 1973-1974. The exporter of Groningen gas, by linking its border price to an international index of low-sulfur heavy fuel oil prices, was able to capture available rents. In the case of exports to Italy, which were being made at a fixed price, political negotiation was necessary before the price could be raised.

By the time of the second major international crude price escalation in 1979-1980, during and following the Iranian revolution, crude oil prices had become the standard for European international gas prices in new sales, reflected in the early 1981 contract for the sale of Stafford gas to German, French, and Belgian distributors. That gas, of course, has yet to flow.

A 1980 report by the Norwegian Ministry of Petroleum and Energy commented on the established European practice of escalating international gas prices to indexes for heating oil prices. However, it went on to argue that "even at increasing degree, the value of the gas on the market is decided by the prices of alternative sources of energy in the most profitable segments of the market, particularly the domestic market, where the alternatives will be mainly kerosene and gas oil as well as electricity." The Norwegian report argued that natural gas prices should not be tied to heavy fuel oil and noted that the relationship of gas export prices to crude oil prices had then recently been accepted in the contract for the sale of Stafford gas to the United States.

At the same time, it would be fair to note that in the 1981 agreement the sale of a large additional volume of Soviet gas to Western Europe, the basic price was seemingly not directly related to crude oil prices, and escalation was related to heavy fuel oil, being oil mostly, with only a minor element of indexation to crude oil.

The Soviet government, in describing the situation in North America as well by 1982-1983 we seem to have come back full circle to a buyer's market. I wrote this article before I saw a Wall Street Journal article on Soviet gas suggesting Europeans (or Russians) are going to have a lot of trouble in the late 1980s in dealing with the floor price and take-or-pay provisions of the 1991 agreement.

Declining natural gas demand and an increased supply in the lower 48 states have created a deliverability surplus in the United States estimated at 2-4 Tcf or 10-20 percent of supply. Strong interdependence, particularly from residual fuel oil in the industrial sector, is placing pressure on gas prices in the market. Foreign suppliers are not isolated from this pressure.

U.S. Interstate pipelines are attempting to lower their gas purchase costs by price renegotiation where possible and by reducing higher cost supply in their gas mix. Because virtually all U.S. importers of Canadian gas have been successful in renegotiating lower contractual minimum purchase obligations, 1983 Canadian exports are about 40 percent of authorized licensed volumes. As in the past when trade difficulties arose, attempts are being made to find a mutually acceptable solution to the current problem. The Canada-United States Energy Concentration Mechanism is proving a useful forum for government-to-government discussion of policy issues.

At the commercial level, the U.S. industry has expended considerable effort in explaining the recent changes in gas marketing to their Canadian counterparts. Similarly, the Canadian Petroleum Association, the Independent Petroleum Association of Canada, and individual gas producers and exporters have been very active in relaying their concerns to the United States at political, official, and industry levels. To some this process may seem painfully slow. It is, however, an example of the benign intervention described earlier in that it seeks to ensure a smooth transition to a new market reality and to avoid irrevocable damage to our gas trade relationship.

The patient approach does have its reward. Because we have not been forced to respond to unilateral fiat, Canada has been able over the past year to introduce additional flexibility into its export pricing mechanism.

In April 1983, Mr. Chretien, our Minister of Energy, indicated his thoughts on the future of Canadian gas export pricing: "I am satisfied that in the long run Canadian gas will have to be competitive if it is to be sold in the United States. But I am also satisfied that the United States recognizes the need to pay a premium for secure long term supplies." Also in April, the border price was reduced 11 percent, from U.S. $4.94 to $4.80/MMBtu, reflecting a corresponding drop in Canada's oil report costs. In July, a volume-related incentive pricing (VRIP) scheme was introduced which offered importers a 75 percent discount from the border price, for gas taken over a base level, equal in most cases to 50 percent of the annual quantity of gas licensed for export.

On November 1, 1983, an additional element of flexibility was added to this program so that eligible importers could purchase incentive gas each month. Depending on the market area, it may well be possible for incentive gas to be sold in much the same way as in producer-consumer direct industrial sales programs recently introduced in the United States.

We have estimated that, taken together, these two price reductions will result in a saving to U.S. consumers of about U.S. $500 million to October 31, 1984, when VRIP expires. In the context of the U.S. gas market as a whole, this may not be significant, but the impact will be felt by consumers in regional markets, most notably northern California, where
Canadian gas accounts for some 40 percent of supply. Apart from these pricing measures implemented by the Canadian government, our exporters have agreed on or are negotiating amendments to their export contracts. These involve both reductions in future take-or-pay obligations and provisions of relief on prepayments already due from U.S. importers. The financial relief to importers involved in contract adjustments means, of course, a corresponding loss of revenue to Canadian producers. These costly adjustments have so far received prompt Canadian regulatory approval, a further indication of our flexibility.

As always, the future is uncertain. The U.S. government has advised us that a new, more flexible framework for our bilateral gas trade is warranted. In Canada, we are carrying out, in conjunction with the provinces and industry, a review of a number of export pricing options, with a view to implementation beyond 1984. This process will not be easy. Many questions remain: Will world oil prices remain stable? What will be the relationship of heavy fuel oil to crude oil prices? How long will the current U.S. deliverability surplus last? Will the North American economy continue on a measured pace to recovery? Will the U.S. gas industry be able to cope with a cold winter and the demand posed by economic recovery?

Given our past history of bilateral trade cooperation, we are confident that ways can be found, acceptable to both governments, to put in place contractual arrangements which will recognize market circumstances and opportunities. We look to the regulatory process to help smooth the transition.

PRODUCER INCENTIVES AND GAS CONTRACTS IN DEVELOPING COUNTRIES

Keith F. Palmer

The gas industry in most developing countries is in the very early stages of development, and experience in evolving policies and institutions conducive to rapid growth of the industry is very limited. At the same time, in many of those countries there is surprising potential for rapid growth of gas production to meet domestic energy demand and displace more expensive energy supplies. If this rapid growth is to occur, governments will need to evolve a gas development strategy which ensures that exploration and development investments take place, that a transmission/distribution system is financed and built, and that gas markets are developed. Evolution of such a strategy will have to include appropriate decisions on producer and consumer pricing; on national gas institutions; on the role of the private sector as equity investor and financier at each stage of production, transmission, and use; and on the role of the public sector as investor, financier, and/or regulator. This paper focuses on one aspect of such a strategy: developing a producer pricing policy conducive to efficient and timely exploration and development of gas reserves by private investors.

We first review briefly the main objectives of any government when establishing a producer pricing policy. We then take a brief look at the characteristics of the existing gas industry in developing countries and note ways in which it differs from the industry in developed countries. In particular, we note those differences which affect the producer pricing practices currently in use. Next, we define and
derive the economic value (marginal opportunity cost) of
gas and argue that this is the appropriate basis for producer
pricing. We then note some of the reasons, in practice,
this is not being utilized and recommend profit-sharing
measures which, combined with opportunity cost pricing, would
meet both the equity and efficiency objectives of the govern-
ment as described earlier. The proposed methodology is illus-
trated by reference to the case of a major gas producing
developing country. The analysis is then extended to consider
some of the problems which arise when there is substantial
supply uncertainty, and the role of take-or-pay provisions
in supply contracts as a means of reducing producer risk
is discussed. The final section outlines the main conclusions
of the paper.

Objectives of Producer Pricing Policy

The objectives of producer pricing policy should include
economic efficiency; managerial efficiency; equity; and admin-
istrative simplicity.

Economic Efficiency

This has at least two important aspects. First, the
policy should ensure that the total supply of gas is delivered
at minimal cost. If the available supply exceeds demand,
and since unit costs vary among fields, then it is important
that there be an automatic incentive both for producers to
select the least-cost set of fields to meet initial demand
and to add new fields where the incremental cost of expan-
sion from existing fields in order of least cost. The framework also, to the
maximum feasible extent, should provide for supply flexibility
over time as new discoveries are made to ensure that the
supply pattern remains the least cost. Second, since unit
production costs increase over time both within fields (as
reservoir pressure declines) and between fields (as higher
cost fields are brought into production), the policy framework
should ensure continued incentive to invest as costs rise
over time whenever marginal costs are lower than the value
of the additional gas to the economy. In countries such
as Nigeria, where there are many small fields, efficiency
considerations are of great importance.

Managerial Efficiency

This refers to the need to retain producer incentives
to minimize investment and operating costs by making
the return which they receive responsive to their performance.
This implies selection (explicit or implicit) of efficient
marginal tax rates such as guaranteed rate-of-return formulas,
where excessive costs are passed on to the government or

...
Table 1. Selected Statistics on Natural Gas Production and Consumption in Developing Countries, 1978

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<tr>
<th>Country</th>
<th>Total production (Mcmce)</th>
<th>Associated gas (percent)</th>
<th>Total marketed (Mcmce)</th>
<th>Percent exported</th>
<th>Domestic consumption (Mcmce)</th>
<th>Private sector producers</th>
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<td>96</td>
<td>0%</td>
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</tbody>
</table>

fails, however, to meet the other objectives, since there is no incentive to develop the least-cost set of fields or to optimize the production rate from individual fields. There is also no incentive to minimize costs, since waste and “gold plating” are fully charged to the government or the consumer. Furthermore, this approach is extremely demanding administratively; the gas authority must have an independent view of which fields to develop, of appropriate production rates, and of “reasonable” costs, since there are no built-in controls. In short, the fixed rate of return formula offers every opportunity for conflict and delay in establishing wellhead prices and ignores efficiency objectives.

**Expected Rate of Return**

Under an expected rate of return approach, a base price is set for each field prior to development at the level (based on expected development and operating costs and production forecasts) which will allow the producer a reasonable return on investment (agreed upon by negotiation prior to development). The base price is typically indexed to cost inflation movements in petroleum prices, or some weighted average of the two. The latter is the approach adopted in Thailand. Administratively, it is simpler than the guaranteed rate-of-return approach (but see below) since the base price and indexation formula are established only once for each field. However, renegotiation of the price becomes necessary in the event of significant departures from expected costs and/or production and if subsequent incremental investments, for example, in field compression, elicit higher marginal costs are required.

This approach does provide a better balance than does guaranteed rate of return between the equity objective and retaining incentive for managerial efficiency; once the price is established based on expected production and cost, there is a strong incentive for the producer to minimize actual costs and increase production above the levels anticipated when setting the base price. However, there is no incentive to develop low cost fields first or to switch production among fields to minimize resource costs. Also, a bias is introduced to produce the fields below the optimal rate. In addition, the expected rate-of-return approach, although simpler than the guaranteed rate-of-return, remains administratively very demanding. The government authority must have an independent view of which fields should be developed, of optimal production rates, and of costs since the producer has an incentive to distort these data to increase the base price. This implies scope for long delays and bad feeling, both with setting the price and subsequently if actual values differ from expected values and/or further investment is required. Finally, since a separate price has to be set for each field and renegotiated periodically as marginal costs rise, the approach is very demanding on the time of the gas authority staff.

Wellhead price regulation is not unfamiliar to those who work in the U.S. gas industry. What makes the situation much more difficult, however, in developing countries is that “regulatory risk” is much greater. Pricing decisions are made by technically weak government agencies with little or no experience in the gas industry, and pricing decisions rapidly tend to become politicized, particularly since investors are foreigners. This frequently gives rise to long delays in reaching decisions and to commercially unwise, politically biased decisions with resultant major distortions and delays in urgently needed investment programs. The prevalence of regulatory risk in developing countries is so great that any system which minimizes this risk must be viewed as a major improvement.

**The Economic Value of Natural Gas**

The basic economic principle that facilitates efficient consumer and producer decisions is that the price of natural gas should be set near its marginal opportunity cost. In this section we shall define that term and illustrate how it can be determined in practice. In some countries, marginal opportunity cost pricing is complicated by uncertainties about reserve size and the market growth rate. Before considering these complications, however, we focus on the problem of determining the opportunity cost of gas in a country where gas supply and demand can be predicted within a reasonable range.

The opportunity cost of gas, or any other commodity, is the price that will equate supply and demand. Where, as for crude oil, transport costs are low relative to the value of the product, there is an identifiable international price. With natural gas, however, international trade opportunities are limited, and the price which equates supply and demand may vary substantially among countries depending on their respective resource endowments and gas demand. A simple illustration of the pricing of gas with limited international trade opportunities is shown in Figure 1. The demand curve indicates the maximum price for gas that users would be willing to pay (rather than use an alternative input) for a range of possible consumption levels. The supply curve defines the price needed by producers to induce exploration for, development and transmission of, gas across a range of possible production levels. The supply curve is strongly upward sloping because marginal supply costs rise as higher cost fields are brought into production. The opportunity cost of gas in this simple case is $\pi$ and production would be $Q_f$, since at this point marginal supply costs are equated...
with marginal willingness to pay.

The Demand Curve

An example may help to clarify how this simple theory can be applied in practice. Figures 2A and 2B show an estimated demand curve for gas in major producing developing countries, using data derived from a recent World Bank study. Figure 2A shows the demand curve for 1990 and Figure 2B the corresponding curve in 2000. The length of each "step" represents the quantities of gas that could be consumed for that purpose as indicated in gas market studies. The total height of each step represents the estimated netback value of gas in that use, that is, the maximum price the user would be willing to pay in that use rather than move to the next cheapest alternative input. In this country the highest value use of gas is in peak power generation (where it displaces diesel oil), followed by residential and commercial. The total amount of gas that can be consumed for these purposes in 2000, however, represents less than 10 percent of the potential domestic market. The bulk of potential gas use is in the power and industrial sectors, displacing heavy fuel oil in baseload generation and primarily light fuel...
oil in the industrial sector. The LNG netback value is based on a 1,000 Mscf/d plant. As can be seen by comparing the figures, the length of the steps increases over time as demand grows. The height of the steps will change in line with assumptions about the prices of substitute inputs.

The Supply Curve

Turning now to the gas supply picture, Figure 3 illustrates a stepped cost function; the length of each step represents an amount of sustained production that could be delivered for the incremental cost plotted on the vertical axis. The first (lowest) step in this function shows an amount of 560 Mscf/d of onshore, non-associated gas delivered to the city gate at a cost of U.S. $1.20/MMBtu. Subsequent steps show the quantities of additional non-associated gas from onshore fields and onshore associated gas, at progressively higher costs reaching U.S. $1.65/MMBtu at an aggregate production rate of 2,300 Mscf/d. The sum of these steps gives the country's projected gas supply curve in 2000 based on today's proven reserves. The supply curve shown in Figure 3 is, of course, a simplified picture of the supply potential. The supply costs are based on (constant 1983) estimated field development costs for known fields, transmission costs to the city gate, and in the case of the non-associated gas a small depletion premium reflecting the cost to the economy of using up an exhaustible resource.

Having discussed the derivation of both demand and supply curves, we are now in a position to superimpose the two in order to determine the opportunity cost of gas in this country. Figure 4 shows the result. Based on the supply potential defined in Figure 3, gas availability would be sufficient in 1980 to meet all of the potential uses, including baseload power generation. In 2000, despite the rapid projected growth of domestic demand and the addition of a 1,000 Mscf/d LNG plant, gas availability would continue to be sufficient to meet the entire demand. The opportunity cost of gas in each year is given by the intersection of the supply and demand curve. In this case, since excess supply persists throughout the planning period, this is given by the marginal cost of the most expensive unit of gas needed in that year. The opportunity cost of gas in 2000, for example, is $1.80/MMBtu. To establish a pricing framework designed to guide investment decisions over the next fifteen to twenty years, the real price of gas should be set equal to the long-run opportunity cost, $P_r$ in Figure 4. The nominal price $P_t$ in the base year would be indexed for cost inflation to $P_{r,t}$ it constant in real terms. Since $P_t$ is determined at the city gate, the price paid to producers into pipeline would be reduced by transmission costs. The national gas authority would undertake to

![Figure 3. 2000 Gas Supply](image-url)

![Figure 4. Opportunity Cost of Gas](image-url)
purchase actual gas demand from producers at the uniform price $P_t$. There would be incentive to develop all fields with marginal costs less than $P_t$ (less transmission costs) and incentive for gas utilization in all potential uses where the netback exceeds $P_t$. There would be a need for additional capacity, perhaps every five years, to revise the uniform price for incremental supply in line with changed supply and demand forecasts, but this would be a relatively simple task compared to regulating prices for individual fields.

### Profit Sharing Formulas to Achieve Equity Objectives

While the economic advantages of opportunity cost pricing are clear, and, as shown above, it is not an impossible empirical task to derive such prices, it must be admitted that this has not been a common approach. There are several reasons, the most prominent being the concern, noted earlier, about equity.

Pricing at marginal opportunity cost means that intramarginal producers reap "windfall" profits. For example, in Figure 4, if gas is priced at U.S. $1.65/MMBtu, then the least-cost producer would earn windfalls of U.S. $0.63/MMBtu, the excess of the price over his marginal cost. In the gas industry, wellhead price regulation with its attendant problems has been the standard response to limiting windfall profits. In contrast, in the case of oil, the problem has been handled through various profit-sharing arrangements. This latter approach is highly preferable since profit sharing, properly designed, combined with uniform gas pricing can limit windfalls while retaining incentives for economic and managerial efficiency. A variety of different profit-sharing schemes developed for oil could be applied to gas. Recent innovations linking government profit sharing directly to actual field profitability further enhance the ability of profit sharing to meet both efficiency and equity objectives. Using this approach there is an automatic reduction in the spread between fields first, to optimize production rates, and to minimize costs. Perhaps most important, the approach minimizes regulatory intervention since the government need concern itself only with auditing actual revenues and costs.

A second objection to opportunity cost pricing in some countries is that the price of oil futures may be subsidized (or, more rarely, taxed) at levels which would encourage uneconomic fuel choices. For example, if fuel oil were subsidized and sold at a price equivalent to U.S. $1.15/MMBtu, then pricing gas at its opportunity cost of U.S. $1.65/MMBtu in the case shown in Figure 4 would discourage fuel oil users from shifting to gas. Clearly, the best solution to this problem would be to remove the fuel oil subsidy, but if that is not immediately possible, the government should consider delinking the producer and consumer prices of gas to permit the consumer price to be competitive with that of fuel oil, while retaining the producer's incentive to explore and produce gas.

### Pricing Natural Gas under Conditions of Uncertainty

In countries where the known stock of gas reserves is large relative to domestic demand, the determination of marginal opportunity cost is relatively straightforward. The situation is much more complicated in a country where the possible increments to supply from new exploration are large relative to domestic demand; in this case the marginal value of gas in that country can be altered dramatically by a new discovery. This is illustrated in Figure 5A and Figure 5B. Assuming domestic gas demand exceeds $D_1$, in Figure 5A domestic gas production is $Q_0$ up to the point at which marginal costs equal the price of the alternative input $O_D$, and we assume the supply-demand gap $Q_D$ is met by fuel oil. Figure 5B assumes a significant gas discovery with costs of production below $O_D$, which shifts the gas supply curve to the right, to $O_D$. Domestic gas supply now completely displaces fuel oil, and the marginal value of gas is reduced to $Q_0$, with production $Q_0$. The diagram illustrates that whenever uncertainty about the supply curve of a nontraded good is large relative to domestic demand, then the expected price of that good is also very uncertain.

Developing countries can usefully be categorized into those which are gas supply constrained and those which are gas demand constrained. In the former case, a scarcity of supply relative to demand means that a predictable value can be placed on additional discoveries of gas on a delivered basis up to the limit of excess demand. In demand constrained countries, domestic demand is small relative to proven gas reserves, so the marginal value of gas in the ground approaches zero. Different approaches will clearly be required for the two types of countries to promote appropriate levels of exploration investment.

In supply constrained countries, supply uncertainty can be handled through contractual take-or-pay provisions combined with opportunity cost pricing. If the government can predict with reasonable confidence the magnitude of the projected gas supply-demand gap over the medium term and the marginal netback value of the alternative input that will be used in the absence of gas, then it is possible to provide exploration incentives in the form of commitments to purchase gas, up to the quantity of the expected supply-demand shortfall, at a price equal to the opportunity cost of that increment. For example, if a gas supply shortfall in a country is expected to result in construction of thermal
power plant using fuel oil equivalent to X Mscfd, then the government would undertake to purchase additional produced gas up to X Mscfd at fuel oil parity. This incentive would act as a stimulus to additional exploration and development by private investors at the cost of transferring market risk to the government. The price and take-or-pay provisions would be combined with profit-sharing arrangements to ensure that a high share of producer rents were transferred to the country. The transfer of market risk from the investor is justified in developing countries by the fact that a large part of the risk is essentially political risk. Following discovery when supply arrangements have to be negotiated with the government, a government monopoly transmission company, and/or government-owned power utility, the investor’s market risk relates in large part to fear that it will be unable to negotiate commercially appropriate contract terms because of political interference. The government, of course, is better able to manage the market risks because it has direct influence on the government-owned corporations.

While take-or-pay and guaranteed price provisions will be necessary to induce early field development, these should be limited both in the quantity of output to which they apply and, over time, to the minimum consistent with financing the investment. Under conditions of supply uncertainty it must be expected that the opportunity cost of gas will rise or fall over time in line with changing supply-demand conditions. By limiting take-or-pay provisions at a fixed price and phasing them out over time, marginal supplies of gas can be contracted at cost incremental demand at the revised estimate of opportunity cost.

Conclusions
In most developing countries, if natural gas exploration and development is to take place in an efficient and timely manner, it will require the participation of private investors experienced in the oil and gas business. To encourage such participation will require an enlightened producer incentive framework designed to ensure that the needed investments take place. In developing countries, even more so than in
the industrialized world, regulation of wellhead prices by the government is likely to be a serious deterrent to the timely expansion of gas supply. We have argued in this paper that the appropriate pricing basis for efficient investment decisions by the producer is to establish a price equal to the long-run marginal opportunity cost of gas in use in that country. This price cannot be set by reference to any simple proxy, such as fuel oil parity, because the economic value will vary among countries depending on the supply and demand balance and export opportunities. We have also argued that the balance between efficiency and equity objectives which the government naturally seeks can best be achieved by uniform gas pricing at the long-run marginal opportunity cost combined with profit-sharing arrangements identical to those already utilized to extract rents in the oil sector. Under conditions of uncertainty, similar procedures can be used combined with contractual take-or-pay provisions.

Notes

1. "Rents" are profits in excess of the (risk-adjusted) return to capital required to induce the exploration and development investments. For further discussion see the last section of this paper.

2. Further details of practical profits taxes are described in K. F. Palmer, "Mineral Taxation Policies in Developing Countries: An Application of Resource Rent Tax," IMF Staff Papers, vol. 27, No. 3 (September 1980).

3. The guaranteed price need not be 100 percent of the expected economic value of incremental supply; it could be, say, 70 percent or even 50 percent so long as the price remains above the expected marginal cost of exploration and development of new reserves by a significant margin so that producer incentives are retained.

Natural gas pricing practices in developed and developing countries

Afsheneh Mashayekhi

Natural gas reserves are widely distributed all over the world. As a group, more than fifty less developed countries (LDCs) hold almost 45 percent of currently proven reserves, which were more than 1,600 Tcf as of January 1983 (see Table 1). Many gas discoveries in LDCs often result from a search for oil and have not been fully evaluated because of the lack of immediate incentives and sufficient prices to invest in their development. Reserves are being reevaluated upward as governments in these countries become aware of their potential contribution to energy supply. For many LDCs, even currently proven reserves of gas could supply about half of their long-term commercial energy needs. There is good reason to believe a large number of LDCs are embarking on gas development and are facing complex questions, among them the pricing of gas at both the producer and consumer levels. However, LDCs generally lack an accepted framework for determining appropriate gas prices. In most gas-consuming countries, gas prices are a result of government regulations, institutional framework, and social and political pressures which differ among countries. Unfortunately, the experience in most developed nations is not always a good

Note: The views expressed here are those of the author and do not necessarily reflect the position of the World Bank.
Table 1. World Natural Gas Supply

<table>
<thead>
<tr>
<th>Region</th>
<th>Volume (Tcf)</th>
<th>Percentage of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>347</td>
<td>9.6</td>
</tr>
<tr>
<td>Western Europe</td>
<td>179</td>
<td>5.0</td>
</tr>
<tr>
<td>Eastern Europe</td>
<td>1,496</td>
<td>40.6</td>
</tr>
<tr>
<td>Latin America</td>
<td>214</td>
<td>5.9</td>
</tr>
<tr>
<td>Africa</td>
<td>249</td>
<td>6.7</td>
</tr>
<tr>
<td>Middle East</td>
<td>888</td>
<td>25.0</td>
</tr>
<tr>
<td>Asia</td>
<td>263</td>
<td>7.2</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,597</strong></td>
<td><strong>100.0</strong></td>
</tr>
</tbody>
</table>


example for LDCs. This is partly due to the different patterns of gas use, and use patterns have important implications for the value of gas and therefore its price.

Most of the natural gas produced in the world is currently used domestically due to its relatively high cost. The United States is the largest gas consumer and together with the Soviet Union accounts for about 65 percent of total world consumption. Furthermore, only in developed countries can a share of about 85 percent of the world total. The average share of gas in LDCs is only 7 percent of their total commercial energy consumption, compared to a share of about 10 percent for OECD countries. The sectoral pattern of gas use in the OECD, a rapid period of growth particularly in gas producing countries, is now shifting from power and industrial uses to residential, commercial, and other purposes, with increases in prices of natural gas. The share of gas in total OECD consumption, however, is expected to remain constant despite the changes in the structure of demand.

The pattern of demand in LDCs is very different, and the share of gas in their total energy consumption is expected to increase. In many LDCs the main potential consumers of gas are power, industrial, and patrimonial, which use gas as a fuel (generally to replace fuel oil) or as a feedstock. Residential demand is relatively small since many LDCs have warm climates and require no space heating. Therefore, for natural gas to make a significant contribution to the energy sector, its share in industrial and power sectors is critical. In Pakistan, for example, which has a relatively mature gas industry after more than three decades of experience, the share of gas is about 83 percent of total primary energy consumption and amounted to more than 250 Bcf in 1981; the

market consists of power (35 percent), industry (35 percent), fertilizers (28 percent), and residential and commercial (14 percent) users. In some countries (for example, in many African nations) with a less diversified and developed industrial infrastructure, a larger share of gas could be used in the power sector, where it could replace petroleum products or expensive hydropower; more than 50-60 percent of the market could be in the power and industrial sectors. In some poorer countries without a diversified industrial base, unconventional uses (for example, in agriculture and transport) are particularly important since they could replace gasoline, diesel oil, and other high value fuels.

The share of gas in total energy consumption varies among LDCs. In some, such as Pakistan, Argentina, Mexico, Algeria, Bangladesh, and Venezuela, gas markets are already large, and natural gas constitutes more than 20 percent of total primary energy consumption. In many LDCs the share of gas could be increased through the development of markets up to a maximum of 50 percent of total commercial energy consumption. Since the markets are still expanding in most LDCs, it is important that gas prices be competitive to ensure a more rapid penetration of natural gas. This situation is very different in many developed countries with mature natural gas industries and markets, where pricing objectives are mainly to keep market shares constant.

This paper first provides a general framework for gas pricing similar to that developed by other public utilities. It then describes the gas retail pricing practices of some developed countries, namely France, which is a gas importer, and the United States, which is a gas producer. Next, the pricing practices in LDCs are discussed using a study of Pakistan and Bangladesh. The final section briefly compares gas pricing practices in developing and developed countries.

Gas Pricing Framework

Since natural gas shares many characteristics of public utilities, the traditional, neoclassical welfare economics framework outlined in the public utility literature is generally appropriate for the gas pricing problem. The objectives of public utility pricing are, generally: efficient allocation of resources; equitable allocation of resources; financial viability of production and transport companies; revenue generation for the government; and ease of administration. Given the constraints that the financial viability objective must be met, economic efficiency is considered the benchmark for gas pricing against which any deviations to accommodate other objectives should be measured.

For many public utilities a marginal cost pricing approach is now an acceptable basis, but natural gas utilities often adopt a different method. Some use only average historical
costs. Others include marginal costs as one of the components, as in France. In the United Kingdom, while the gas utility finds marginal cost pricing would be difficult in practice, a recent study commissioned by the government strongly advocates it. In the abstract, marginal cost is the incremental cost of optimum adjustments in the gas system expansion plan and gas system operations to meet small increments of demand. The approach estimates the marginal costs of serving different consumers at different times in various regions. Setting prices to provide a signal that additional gas output is justified implies that price should be at a minimum equal to the marginal cost of output. Since gas is a depletable resource, this implies that the consumer price should reflect not only the marginal physical cost of expanding consumption but also the value of the depletion. The marginal opportunity cost is generally more difficult to estimate for gas than for other public utilities because of supply and demand uncertainties, joint costs, and rent estimation.

Marginal economic cost of supply provides a lower boundary to prices. In countries with large gas surpluses, prices would be close to the marginal cost; in gas deficit countries, prices would include a larger depletion allowance. The gas transmission and distribution services are similar to other utility services by power, where use of marginal costs in pricing is prevalent. As applied to natural gas transmission and distribution, marginal cost pricing ensures that the benefits of expenditures in the sector exceed the costs.

One of the greatest difficulties in the analysis of gas costs is that the technology of natural gas development and transport is subject to economies of scale and requires large indivisible investments. Investments in gas infrastructure, following from the technology of gas recovery coupled with prevailing legal arrangements, are incurred at discrete stages. Costs of initial field development, such as drilling and equipping gas fields, gas processing facilities, and rein transmission lines, are a high proportion of the overall lifetime costs.

A gas supply system can be divided into four interrelated stages, as shown in Figure 1. First, exploration establishes the level of proven reserves. Exploration costs include the estimate of the finding cost of natural gas. Second, reserves are evaluated as to commercial potential. Third, development and production require large indivisible investments for drilling, field preparation, field gathering, compression, separation, purification, and gas transmission. Fourth, gas to produce a pipeline quality product to meet contract volume, quality, and pressure requirements. The final stage is the transmission of gas from the field or gas treatment plant to the city transmission facilities. Transportation and distribution costs are subject to significant economies of scale until the maximum capacity of pipelines is reached.

Production of the first increment of gas thus requires a large initial expenditure in exploration, development, and transmission. Production of additional volumes necessitates little additional expenditure until maximum capacity is reached. Thereafter, indivisibilities and diminishing returns in providing gas to meet demand lead to additional discrete and discontinuous investments and raise the marginal costs (see Figure 2). The characteristics of investment in natural gas development and transport for a given field imply that the marginal cost curve falls sharply for relatively low volumes of recovery and rises as cumulative production increases to more than 60 percent of estimated recoverable reserves.

Due to the capital indivisibilities, costs will be marginal at some times and nonmarginal or discontinuous at others, as illustrated in Figure 3. Let us begin with the demand curve D. If production from a given gas field is below maximum capacity, the only costs immediately attributable to additional consumption are the incremental operating and maintenance costs, or short-run marginal costs. Once production is at capacity and the demand curve shifts, gas system expansion requires drilling in existing and new fields, new gathering and perhaps pipeline facilities, as well as additional operating and maintenance costs. The resulting large cost fluctuations could cause price changes over time that would not be acceptable to consumers. Therefore, a definition of long-run marginal costs that fits the structure of investments in gas development and transport is required. Costs must be estimated within a sufficiently long-run framework to incorporate the investment process.

Since natural gas resources are deplet, a critical question arises as to how they should be priced to allow
for their foregone value. Starting from the seminal work by Harold Hotelling, a large literature has developed on this subject. Under conditions of constant marginal costs, certainty of future demand, and fixed stock of homogeneous resources, the Hotelling basic principle indicates that the optimal price of the resource net of extraction costs must rise over time at a rate equal to the rate of interest, as shown in Figure 4.

The price at time 0 is equal to the marginal cost $Og$ plus $xy$. It rises at the rate of interest $(1)$ to $y_0$ when the deposit is exhausted, and a higher priced energy substitute will enter into use. If extraction costs are expected to rise at a rate $(1)$ while $(1)$ is the interest rate, then the depletion premium will grow at the rate $(1 - (1))$.

The appropriate price, therefore, from the point of view of economic efficiency should allow for the marginal physical cost of gas supply as well as the value of foregone resources. The lower boundary to prices is given by the marginal cost of gas supply to the consumer; the effective ceiling for consumer prices would be the economic (border) price of the next best alternative resources, or the opportunity cost of the gas.

The marginal opportunity cost of gas depends on the relative supply and demand in any given country. Therefore, in a supply constrained country, even if the marginal physical cost of gas supply is low but depletion is expected relatively soon, opportunity value of gas will be high due to the value of "rent" element. Conversely, in a demand constrained country, the economic price of gas will be close to the
marginal physical cost of gas. Obviously, the strict marginal cost pricing will have to be adjusted to allow for financial viability, since it may lead to significant surpluses or losses. Accounting losses and surpluses have to be absorbed somehow, and it is often difficult to achieve the necessary transfer of real income without creating distortions of consumers' or producers' choice as severe as those encountered in deviating from marginal cost pricing. The marginal cost pricing framework will also have to be adjusted for second-best considerations when other prices in an economy are not efficiency prices, as well as for the real cost of foreign exchange, which may differ from actual exchange rates, by using shadow prices. In areas where natural gas is provided to a poor community, it may also be desirable to modify the marginal cost pricing approach by using lifetime rates for very small consumers in selected areas.

Pricing Practices in Developed Countries

The history of natural gas pricing at producer and consumer levels indicates that social, political, and regulatory factors have been the major determinants of gas prices, and prices have not always followed an economic rationale. Natural gas consumption in the United States and Western Europe grew rapidly in the late 1940s and throughout the 1960s and 1970s due to the low price of gas relative to competitive fuels. In the 1980s this price relationship became undone as oil prices fell in real and nominal terms, while gas prices increased or remained constant, which led to a loss of share for gas in many markets.

Gas Pricing in France

Since France is mainly a natural gas importer, producer level prices are determined through negotiation with gas exporters. The principle of gas pricing at the retail level has been based on the imported base price plus the cost of transmission and distribution. Marginal costs are considered together with other factors, such as average distributed costs, the economic value of gas measured by the price of alternative fuels, and political and historical factors.

For residential, commercial, and small industrial customers of gas, five tariffs apply (see Table 2). There are two-part tariffs (fixed customer and energy costs) for customers not using gas for space heating and three-part tariffs for customers who do, including a capacity cost.

For the large industrial users (more than 17 Mcf), tariffs consist of fixed yearly charges, capacity costs, and energy costs. The average cost of gas in 1981 was about $4.40/MWhr. Gas prices vary for different users and in

Table 2. Residential, Commercial, and Small Industrial Customers in France, in U.S. Dollars

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Gas use</th>
<th>Market range</th>
<th>Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;Ed&quot; or &quot;general&quot;</td>
<td>up to 5,400 cf</td>
<td>$7.10</td>
<td>$7.10</td>
</tr>
<tr>
<td>&quot;Ed&quot;</td>
<td>from 5,400 cf to 10,000 cf</td>
<td>$7.60</td>
<td>$7.60</td>
</tr>
<tr>
<td>&quot;Ed&quot;</td>
<td>from 10,000 cf to 20,000 cf</td>
<td>$8.60</td>
<td>$8.60</td>
</tr>
<tr>
<td>&quot;Ed&quot;</td>
<td>from 20,000 cf to 40,000 cf</td>
<td>$10.40</td>
<td>$10.40</td>
</tr>
<tr>
<td>&quot;Ed&quot;</td>
<td>from 40,000 cf to 100,000 cf</td>
<td>$12.00</td>
<td>$12.00</td>
</tr>
<tr>
<td>&quot;Ed&quot;</td>
<td>over 100,000 cf</td>
<td>$14.00</td>
<td>$14.00</td>
</tr>
</tbody>
</table>

*1981 prices.*
1981 were $8.90/Mcf for residential users and $4.81/Mcf for industrial users. Gas prices in France have remained competitive with alternative fuels until recently, when the price of gas to industrial users was increased, which reduced this sector's market share. The marginal cost of gas supply increased in 1983 due to higher gas import prices, and this has been reflected in the gas prices to end-users.

Gas Pricing in the United States

The United States is a major gas producer and consumer. It relies largely on domestic supplies of gas, plus some pipeline imports from Mexico and Canada and LNG (peak shaving) from Algeria. Production and transport is generally carried out by private companies and is subject to close government regulation, particularly in pricing. Gas pricing practices at the wellhead and consumer levels have been abundantly discussed elsewhere and will not be dealt with here. Gas prices at the producer level consist of many categories of old, new, and other subcategories, with the consequence that gas transmission companies have different supply costs depending on their sources of supply. The gas transmission and distribution network, however, is mainly in place, and therefore transport costs have been falling and are expected to continue to fall until major new pipelines are needed. The current problem of passing on the high cost of the cheap deregulated gas to consumers has led to some market contraction.

At the retail level, the Public Utility Regulatory Policies Act (PURPA) of 1978 required the Department of Energy to conduct a study of gas rates and tariffs. The study, issued in May 1980, strongly emphasized the use of incremental cost-based rates. Some utilities now estimate incremental costs but do not use them in rate design. The most common basis for rate design is historical and embedded costs. Incremental cost studies carried out by some utilities (see Table 3) indicate relatively high marginal cost of gas due to the high cost of peaking and use of LNG and NG, but a falling marginal cost of transport toward distribution.

There is a great variety of rate types used in the United States, including flat volumetric, demand, seasonal variation, two-part (capacity, energy), three-part (customer/capacity/energy), lifeline, and declining block. The most common in the United States are declining block, two-part, flat volumetric with a summer-winter differential, and interruptible. In almost all cases, utilities and regulators have looked into historical average costs as the basis of rates. However, since 1982, marginal costs have increased due to high energy costs (in marginal physical costs) in particular, arising from the deregulated deep gas, with take-or-pay contracts of up to $9-10/MMBtu, far above historical average.

<table>
<thead>
<tr>
<th>General</th>
<th>Large residential volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Costs ($/100 Mcf)</td>
<td>10.02</td>
</tr>
<tr>
<td>Peak Season</td>
<td>7.65</td>
</tr>
<tr>
<td>Off-Peak Season</td>
<td>31.53</td>
</tr>
<tr>
<td>Customer Costs ($/Costs/Month)</td>
<td>10.91</td>
</tr>
<tr>
<td>Demand Costs ($/100 Mcf)</td>
<td>32.02</td>
</tr>
</tbody>
</table>

Source: Public Service Electric and Gas Company, Newark, New Jersey; 1980.

In general, the development of natural gas resources for domestic use in LDCs has been so limited that systematic pricing procedures have not yet evolved. Since most of the gas produced has been associated, countries have not felt the need to establish economically rational pricing rules. Furthermore, the production and transport of gas in many LDCs is often carried out by the government, which also decides gas prices and often on the basis of ad hoc criteria and social and political pressures. In many cases the cost of gas supply is not known because the gas industry is in its infancy and governments have not realized the problem of financing large and lumpy investments in gas infrastructure. Therefore, gas prices do not bear any relationship to their marginal physical cost or other opportunity cost.

Wellhead producer prices are being linked to the opportunity cost of gas in many LDCs where the producer is an international company. However, national oil companies in LDCs have problems in linking producer prices to the value of the gas or even to the cost of the gas. As far as consumer prices are concerned, rate design is much simpler than in most developed countries. In general, there are only a few major consumers. When these customers are large and influen-
Table 4. Natural Gas Prices in the United States, 1973-1982, $/Mcf

<table>
<thead>
<tr>
<th>Year</th>
<th>Average wellhead</th>
<th>Delivered to electric plant</th>
<th>National average</th>
<th>Boston</th>
<th>St. Louis</th>
<th>Los Angeles</th>
</tr>
</thead>
<tbody>
<tr>
<td>1973</td>
<td>$0.22</td>
<td>$0.35</td>
<td>$1.08</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1974</td>
<td>0.30</td>
<td>4.49</td>
<td>1.25</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1975</td>
<td>0.45</td>
<td>0.77</td>
<td>1.54</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1976</td>
<td>0.58</td>
<td>1.08</td>
<td>2.18</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1977</td>
<td>0.79</td>
<td>1.33</td>
<td>2.26</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1978</td>
<td>0.91</td>
<td>1.48</td>
<td>2.33</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1979</td>
<td>1.18</td>
<td>1.80</td>
<td>3.23</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1980</td>
<td>1.59</td>
<td>2.28</td>
<td>3.95</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1981</td>
<td>1.98</td>
<td>2.91</td>
<td>4.56</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1982 Jan</td>
<td>2.37</td>
<td>3.07</td>
<td>4.06</td>
<td>7.27</td>
<td>4.84</td>
<td>3.73</td>
</tr>
<tr>
<td>1982 July</td>
<td>2.40</td>
<td>3.69</td>
<td>5.59</td>
<td>7.78</td>
<td>5.25</td>
<td>5.36</td>
</tr>
<tr>
<td>1982 Sept.</td>
<td>2.52</td>
<td>5.63</td>
<td>7.91</td>
<td>5.46</td>
<td>5.37</td>
<td></td>
</tr>
<tr>
<td>1982 Nov.</td>
<td>2.85</td>
<td>8.18</td>
<td>6.12</td>
<td>4.01</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


Note: The marginal costs in this table are estimated at constant geographically-indexed fuel and capital costs. Taxes, taxes, and royalties and depletion costs, which increase the average wellhead cost to $5.28/Mcf, are excluded.

Table 5. Natural Gas, in Physical Units

<table>
<thead>
<tr>
<th>Country</th>
<th>Production cost</th>
<th>City gas delivery cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Canada</td>
<td>0.28</td>
<td>0.34</td>
</tr>
<tr>
<td>Mexico</td>
<td>0.60</td>
<td>0.66</td>
</tr>
<tr>
<td>Thailand</td>
<td>0.88</td>
<td>1.14</td>
</tr>
<tr>
<td>Tunisia</td>
<td>0.97</td>
<td>1.03</td>
</tr>
<tr>
<td>Venezuela</td>
<td>1.50</td>
<td>1.64</td>
</tr>
<tr>
<td>Indonesia</td>
<td>2.40</td>
<td>2.64</td>
</tr>
<tr>
<td>United States</td>
<td>6.48</td>
<td>6.84</td>
</tr>
</tbody>
</table>
study of gas distribution in Portugal it was found that the peak-day use only for residential cooling and water heating as well as for industrial and power consumers was about 140 percent of the average day; the consumption of the peak month was around double that of the lowest month. In order to develop gas tariff systems that allow for these phenomena, most LDCs will need to (1) estimate demand characteristics (such as load factor, seasonality) of the major types of consumers and determine possible candidates for interruptible services; (2) determine the structure of the marginal cost of serving different types of consumers in different geographical areas; and (3) provide incentives that would effectively promote rapid conversion to gas while minimizing undesirable precedents as the gas market matures.

With a few exceptions, the pricing systems also do not look at the netback to gas in different uses, nor use the opportunity cost of gas determined by integrating the supply and demand sides.

**Gas Pricing in Pakistan**

In Pakistan, the large volumes of gas production and economies of scale in production and transmission have led to low supply costs. The marginal costs for different fields are presented in Figure 5. Pakistan has a relatively mature gas industry, and the production-to-reserve ratio has been increasing. Although present gas costs are low, demand increases there will be a need for supplies from more expensive fields.

Marginal cost over the period 1982-2000 is expected to remain low. This is because the presently producing fields, which have a low marginal cost, are expected to have a large share of total production. However, these fields require compression facilities to maintain production, which increases the marginal cost of gas supply. The production costs of new fields are also higher, and the finding costs of gas are increasing as the success ratio falls. Pakistan is expected to remain in the flat part of the cost curve, presented in Figure 6. Looking through beyond 1990, it will reach the moderately rising part of the cost curve unless a large discovery is made.

Following a period of rapid demand growth and low prices, there is now a serious gas shortage in Pakistan. Prices bear little relationship to the marginal cost or their opportunity cost, as indicated in Tables 7 and 8. They are fixed by the government and differ considerably by class of user, from $0.75/Mcf for power up to $1.75/Mcf for commercial uses. The average industrial selling price (see Table 6) is $1.10/Mcf, which is only about 30 percent of the fuel oil equivalent price. This is due to the low prices in the 1970s that were aimed at increasing the market share of gas.
### Table 6. Average Gas Tariffs in Pakistan, 1983

<table>
<thead>
<tr>
<th>Class</th>
<th>Price ($/Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industry</td>
<td>1.10</td>
</tr>
<tr>
<td>Power</td>
<td>1.00</td>
</tr>
<tr>
<td>Fertilizer</td>
<td>0.80</td>
</tr>
<tr>
<td>Commercial</td>
<td>1.45</td>
</tr>
<tr>
<td>Residential</td>
<td></td>
</tr>
<tr>
<td>- First 8.3 Mcf</td>
<td>0.90</td>
</tr>
<tr>
<td>- Next 4.1 Mcf</td>
<td>1.15</td>
</tr>
<tr>
<td>+ 12.4 Mcf</td>
<td>1.38</td>
</tr>
</tbody>
</table>

a Some power users also pay a fixed customer charge and a lower energy cost ($0.80/Mcf) and have a minimum charge of $58.00 per month.

Fertilizer plants pay a fixed customer charge per month that varies depending on their consumption level.

With excess demand, the need for changes in consumer prices has become evident. The structure of prices to consumers bear no relationship to their peaking needs and, therefore, capacity costs. Power users are subject to a flat volumetric tariff. Furthermore, the transmission and distribution margins set by the government bear no relationship to the investment costs required to expand the gas network and result in a supply constraint. Although there are major gas shortage problems due to space heating in winter, there are also no winter-summer price differentials.

### Gas Pricing in Bangladesh

The issue of the long-run opportunity cost of gas is more complex in Bangladesh. It has large gas reserves relative to domestic demand for the next several decades. This implies that the high value uses of gas as a fuel oil substitute can easily be accommodated, and unless gas can be exported, the opportunity cost of gas will fall to its marginal costs of supply plus depletion allowance, which is expected to be low because depletion is expected to occur in more than thirty years.

The 1962 tariffs are shown in Table 9. The lowest rates ($0.48/Mcf) are charged to the power and fertilizer sectors, which together account for more than 73 percent of total gas sales. Industrial and commercial tariffs are $1.41/Mcf.
Table 9. Natural Gas Tariffs in Bangladesh, 1982

<table>
<thead>
<tr>
<th>Sector</th>
<th>Price ($/Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power</td>
<td>0.40</td>
</tr>
<tr>
<td>Fertilizer</td>
<td>0.40</td>
</tr>
<tr>
<td>Industry</td>
<td>1.41</td>
</tr>
<tr>
<td>Commercial/residential (metered)</td>
<td>1.41</td>
</tr>
<tr>
<td>Residential (unmetered)</td>
<td>1.59</td>
</tr>
</tbody>
</table>

The tariff for two burners per month is 2.59.

Most residential customers are not metered and are charged a flat monthly rate calculated on the number of gas burners owned.

Residential and commercial users are heavily subsidized since tariffs do not cover costs and cause serious financial problems for the gas utility. There are also serious daily peaking problems from 4 to 11 p.m., as well as seasonal problems during winter. There is no storage capacity, and prices do not reflect the structure of capacity costs. There are shortages that result in load shedding.

As indicated in Figure 7, the marginal cost of gas supply could fall in Bangladesh. This depends on whether, once the main field development and infrastructure investments are made, due to economies of scale the marginal cost of producing more gas will fall.

Comparison of Gas Pricing in Developed and Developing Countries

A 1977-1979 study was commissioned by the U.S. Department of Energy to survey the rate structures of gas utilities in most of the United States, several Canadian provinces, and OECD countries with large gas markets. It found an almost complete dominance of tariffs based on average historical costs, often mandated by gas regulatory bodies. The declining block rate is still the most widely used. There is, however, widespread availability of lower interruptible service rates, and several U.S. states and other countries have summer-winter differentials in their consumption charges. Very few examples of progressive charges (that is, increasing with consumption) or lifeline rates were found. Only eleven state regulators responded that they had ever considered the effects of gas curtailment priorities in rate design, and only one had adopted such a rate form. A general theme that emerged from the study was that major institutional and political difficulties are involved in trying to change an outdated tariff structure, even when it no longer serves the best interests of either gas producers or consumers.

The situation appears similar to that of electricity pricing twenty years ago. In that case, academic interest was aroused by the innovative efforts of a utility (Electricité de France) to define and adopt marginal cost pricing. Eventually, the theoretical base that developed during the 1960s and 1970s was streamlined and refined into practical pricing policies that are now in use in many developed and developing countries.

During the 1960s and 1970s natural gas consumption grew very rapidly in many developed countries. In most cases this was partly due to gas being competitively priced relative to other fuels. The key factor during this period was the relationship of gas to oil prices. This changed recently with gas price increases due to more costly deregulated new deep gas in the United States and the higher cost LNG and pipeline gas imported into Europe. In general, gas demand has been reduced, particularly among industrial customers with dual-fired plants. While the recent changes have specific causes, they nonetheless indicate a slowly rising trend in
gas prices over the long run. The supply of low cost gas in many U.S. and European locations will eventually fall, and higher cost supplies will be used. A major reason for the gas shortage in 1978 and the present gas bubble in the United States has been the inadequate pricing policy in the past.

LDCs at present face a different pattern of costs. Nonetheless, on the whole they are repeating the experience of developed countries two decades ago. In many LDCs gas prices are far below prices of competitive fuels. In a few instances, where the country has very large low-cost supplies and a low netback to gas (for example, is an LNG exporter), low prices could be justified on economic efficiency grounds. When the opportunity cost of gas is high, gas prices should be related to the price of the fuel being replaced. Furthermore, the gas prices in most LDCs make no allowance for peaking and seasonal changes. In some this may not be a problem, but in others (such as Pakistan), where there is a major peaking load, the price of gas should allow for the capacity costs to be charged to users.

While very little has been written on the underlying economics of natural gas pricing, in a number of related areas, particularly in water and power utilities, theory is well developed. Much of the large literature on public utility pricing is relevant to the structural aspects of gas tariffs. The literature on depletable resource economics is at least well established, and the underlying Hotelling theory is widely accepted. These can be used to develop and design gas tariff structures in LDCs while taking into account the experience in developing countries.

Notes

1. This share could increase if the gas supply constraint were removed.


3. They exclude a depletion allowance for the value of the exhaustible resource.

4. Therefore, \(- \frac{2C}{\partial C} > 0\) for all \(q; \frac{\partial C}{\partial q} < 0\) for \(q < q_i\), where \(q_i\) is the maximum volume of recoverable reserves before indivisibilities and diminishing returns set in, and \(- \frac{\partial^2 C}{\partial q^2} < 0\) for \(q > q_i\).
ECONOMIC REALITIES OF THE SOVIET GAS AND ALASKA GAS EXPORT PROJECTS

Gary J. Pagliano

In 1984, the Yamal pipeline will begin new deliveries of Soviet natural gas to Western Europe. This has been the most intensely debated energy project in memory because of its perceived effect on East-West relations. The debate reached its zenith when the United States sought to stop, or at least delay, the pipeline's construction because of concerns about Western Europe's future vulnerability to Soviet economic and political pressures. Friction arose because the Europeans and their governments, also U.S. allies in NATO, never wavered in their support of the project. They were more concerned about economic trade benefits and their overall energy supply diversification goals than about international politics. The Soviet Union's initial objectives for the project were primarily related to its domestic energy needs and its hard currency requirements for maintaining and, perhaps, even expanding trade with the West. However, the pipeline became a symbol of bickering among the NATO allies owing to its political benefits for the Soviets. It also became a test of the Soviet system to muster enough resources to build the 2,800-mile pipeline connecting the world's largest gas field, Urengol (385 Tcf proven reserves), to export markets. During 1978-1980, as world oil prices were increasing threefold, the U.S. was attempting to reduce its dependence on oil imports by decontrolling domestic oil prices, enacting the Energy Security Act, and encouraging the construction of the Alaska Natural Gas Transportation System (ANGTS). However, soon after legislation was passed to increase the financial feasibility of the ANGTS project, Exxon announced (in May 1982) that due to changing market forces the project would be postponed for at least two years, which some experts interpreted as indefinitely.

At the same time, construction on the Yamal pipeline, approximately the same size (length) and cost as ANGTS, was going into high gear. Adverse market forces would detract from Yamal's short-term economic viability but could not negate the fact that it would connect the world's largest gas field with major markets in Western Europe, projected to be dependent on gas imports far into the future, or the fact that Soviet demand for capital and materials generated by the project would create significant opportunities for West European countries to sell goods and services at a time when their economies were in trouble.

The ANGTS project, in contrast, has associated with it a much smaller resource base (26 Tcf proven reserves), little or no market potential for its gas in 1982, and a greater risk on investment capital because of project completion uncertainties. While the Soviet and West European governments made substantial commitments, particularly in the financial area, to guarantee Yamal's completion, the U.S. government gave only limited support to ANGTS. This was because ANGTS was a private sector project and, as such, was deemed able by President Carter and Congress in 1977 to secure project financing without federal guarantees. Thus, ANGTS was primarily judged on its economic merits within the framework of the market forces prevailing in 1982.

This paper will analyze the economic aspects of each project, defining in the process the market forces influencing each project outcome. The paper will also examine why the Soviets under current market conditions will have a difficult time expanding their share of the West European gas market. Finally, it will examine a proposal to revive the ANGTS project.

The Yamal Project

The Soviet Perspective

The Yamal project was conceived as part of a major Soviet effort to develop its vast natural gas reserves in western Siberia. Their current five-year plan calls for increasing gas production from this region from 156 bcm (5.5 Tcf) in

Note: The views presented here are those of the author and do not represent the findings or views of the Library of Congress or the Congressional Research Service.
1980 to 330-370 bcm in 1985, and total Soviet flow from 430 bcm to 500-640 bcm during the same period. To accomplish this goal, the Soviets planned to construct six transcontinental gas pipelines about the size of ANGAS. One would be the Yenap pipeline, originally intended to pipe gas from the Yamnburg field, but owing to technical difficulties the line was switched to the more developed field at Urenei (see Figure 1). A major reason for this ambitious plan was simply that it would be cheaper to increase production of Soviet natural gas reserves than to increase production of Soviet oil. The Soviet oil industry has entered a mature stage; their super giant oil fields have pealed, and to expand current production levels would require development of smaller and more costly fields. They continue to have impressive levels of oil reserves, estimated at 65 million barrels, but they

Figure 1. The Soviet Pipeline Network


have 3.3 times more natural gas, and the deposits are far more concentrated. The Urenei and Yamnburg fields alone have more proven reserves than all of the United States. This area of western Siberia, which has at least five other super giant fields, is estimated to have proven and probable reserves of more than 1,000 Tcf.

Another major reason for the plan is that the Soviet Union needs more energy for export-to fulfill rising energy demands of Communist countries, particularly in Eastern Europe, and to generate hard currency in Western Europe for trading requirements. Energy represents the largest source of the Soviet Union’s hard currency export revenues, an estimated 68 percent in 1982, followed by earnings from arms (17 percent), gold (14 percent), and other goods (mostly nonfood raw materials, 11 percent). Energy exports to the West account for 80 percent of Soviet export revenues. With coal exports small and not likely to increase significantly in the future, oil is the only alternative besides gas. Estimates of future Soviet oil production levels range from remaining constant at about 12.3 mb/d for the rest of the decade, to increasing by at least 5 percent annually, factors which point to the Soviets having to use more natural gas.

Time is of the essence; already the Soviets have had to rearrange their energy priorities to reach their economic objectives. In 1982, hard currency demands were responsible for oil exports to Communist countries, particularly in Eastern Europe, being reduced by 200,000 b/d, while oil exports to Western Europe were being increased by 300,000 b/d. In 1983 these currency problems worsened because the price of world oil, the energy source that provides 75 percent of the Soviet Union’s export revenues, was reduced by 15 percent. To help maintain hard currency levels, the Soviets were aggressive price cutters to ensure sales of yet another 300,000 b/d of oil exports to the West. The Soviets increased their oil export level by increasing domestic production slightly, reducing oil exports to their allies, and refraining to the West some of the oil the Soviets barred from the OPEC.

The biggest problem in planning the ambitious gas development plan was to mass enough human, financial, and industrial resources. Clearly, the Soviets had neither the capital nor the industrial capacity to build efficiently the required 232 compressor stations or manufacture the required 23,400 miles of large-diameter pipe. Western Europe became the primary candidate because it had what the Soviets needed-capital, industrial capacity, and a market for its gas.

The Western European View

Western Europe saw in the Yenap project a long-term non-OPEC energy source and a long-term industrial opportunity.
for significant business. Ever since the 1973 oil embargo, Western Europe has tried to reduce its dependence on OPEC oil, particularly from the Middle East. Greater use of natural gas and nuclear energy has been the main strategy to achieve this dependence. A corollary to this strategy has been an effort to diversify natural gas suppliers to ensure greater security of supply. The vulnerability issue was indeed considered by the Europeans in evaluating Yamal, but it was outweighed by the following factors: (1) confidence that other supplies of gas could be substituted in a crisis from Norway, the Netherlands, or Algeria; (2) gas reserves each country claims to have operational; (2) a belief that the Soviets need the hard currency for purchases of United States and West Germany were particularly critical because in some countries the Soviet Union was being offered financial terms that were not even granted to developing countries. After a series of meetings among Western nations in summer 1982, there was a new understanding on minimum interest rates for such loans depending on length of facility and country favored. The Soviet Union was placed in a category of rich industrialized countries paying at least 12.5 percent for long-term credit. The Soviets have yet to accept this new arrangement, which would drain more hard currency from them at a time when projected gas sales from the pipeline may not be as lucrative as thought two years ago.

Gas Sales Contracts and Current Market Conditions

After the Yamal gas sales contracts were negotiated in 1981, it was generally agreed that the Soviets had done very well. The base contract for the gas was between $4.00 and $4.90/MMBtu depending on transportation costs. The price also included an escalator based on a weighted index of crude oil and product prices. Even if reduced inflation and low oil demand kept down the nominal price of oil, the Soviets were supposed to earn a floor price of about $5.70/MMBtu in the late 1980s. The Europeans also agreed to “take or pay” for 80 percent of the contract volumes. All that was coupled with the subsidies, produce a real price for Europeans that was above market rates. However, market conditions in Western Europe significantly changed in 1982. After minor declines in 1980 and 1981, OECD data for 1982 showed a fall of 6 percent in total natural gas requirements. This resulted in a 9 percent decline in community production and a fall in imports from third-party countries. West Germany, for example, decreased its domestic production by 13 percent, and the Netherlands decreased theirs by 19 percent, with Dutch exports falling by 17 percent (having fallen 11 percent in 1981). Gas imports to West Germany fell 8 percent. The decline in European
gas demand can be traced to the following factors: (1) substitution of coal and fuel oil for natural gas in state-owned power stations; (2) a mild winter in 1982; and (3) fuel switching in the industrial sector as gas prices rose relative to coal, fuel oil, and nuclear power.

Much of this decline was not anticipated. Indeed, many demand forecasts for Western Europe in the 1980s have been consistently high.\(^\text{17}\) Forecasts of 1982 levels made as recently as 1979, for example, were as much as 50 bcm too high, or an amount greater than the capacity of the Yamal pipeline.\(^\text{16}\) Projected demand levels for the near future have, as a result, shifted downward in a market already characterized by excess production capacity.

The first to feel this market effect has been the higher priced gas supplier, Algeria, Belgium has announced it will reduce its Algerian LNG offer by 40 percent in 1984 and 1985.\(^\text{17}\) In addition, the French government apparently plans to end its 13.5 percent "political" subsidy paid to Gaz de France, which must take or pay for 9 bcm of Algerian LNG.\(^\text{18}\) Finally, Spain is trying to arrange a settlement with Algeria because Spain broke its take-or-pay contract by buying only one-third of its 4.5 bcm of LNG.

These market conditions have begun to cost a different light on the Soviet gas contracts as the Soviets and the West German importer, Ruhrgas, continue to negotiate final delivery prices. Ruhrgas chairman Klaus Lieben already has implied his company's contractual arrangement with the Soviets is more advantageous than outsiders had previously thought. In May 1983 he announced that the terms would allow Ruhrgas to sell to its end-users at a competitive price, even after oil prices decline and irrespective of the cost incurred to the Soviets for producing and transporting the gas to the West German border.\(^\text{19}\)

Ruhrgas definitely has some leverage for negotiating a more competitive price. West Germany's gas price demand is projected to remain lower than anticipated. The West Germans are already getting 10 bcm of Soviet gas under contracts which come up for renegotiation in 1984, but which do not have minimum price clauses. And the Soviets have counted on West Germany, its largest West European gas market, to contract for 40 percent of Yamal's total delivery, which begins at one bcm in 1986 but grows to 5 bcm by 1990. The Soviets can ill afford to lose the West German gas market or any other in Western Europe. Although the West Europeans have sunk $6 billion into the Yamal project, its cost to the Soviets is much more, particularly because they mobilized such a massive project to complete the project on time. Although it is difficult to measure costs in the Soviet Union, compare the fact that ANRU would have cost $40 to $50 billion (in 1980 dollars). As a result, there has to be growing pressure to get some return on so large an investment as soon as possible, as well as pressure to start the hard currency flowing.

If the Soviets respond to the economic pressures associated with the project, they will have to adjust their gas pricing policy to market realities—declining demand and intense price competition. The alternative is to face sales problems similar to those of Algeria or perhaps Canada, with its problems in the U.S. market. Current Soviet oil export pricing policy to the West will likely be the standard by which gas export pricing is administered, mainly because of the Soviet precedent in dealing with recent Western oil markets when they were also in a declining demand and price competitive situation.

History shows the Soviets have implemented oil pricing policy to adjust rapidly to world markets. Virtually all of their oil sales are linked to spot markets, either through direct sales or contract sales containing prices that follow spot market prices. Since 1982, their oil pricing policy in the West has been aggressive, aimed not only at maintaining but also increasing market share during a period of declining demand and decreasing oil prices. In the first quarter of 1983, for example, the Soviets reduced their oil prices five different times to increase market share and maintain the 1982 flow of hard currency. It is likely that Soviet gas export policy is similarly based on a certain revenue expectation; thus, as with recent oil pricing policy, the Soviet Union will probably reduce its gas price from 1981 levels to accommodate the market situation in the short term.

It should be remembered, however, that the Soviets are looking far beyond the short-term market situation. Gas resource constraints for all practical purposes are minimal in the Soviet Union, since they have as much gas (or more) as Saudi Arabia has oil. As are the Saudis, they are in the export business for the long term.

The ANRU Project: Short-Term Considerations Did It In

In 1977, when the Alaska Highway Gas Pipeline Project was chosen to transport Alaskan gas to U.S. domestic gas markets, it was hailed as a project to make the United States more energy independent (see Figure 3). It would be the costliest project proposal in Free World history. Even though its feasibility was always suspect because of the size and the risk involved, there were factors that kept the project viable. First, the federal government encouraged the pipeline's construction by offering a special Alaska gas (Prudhoe Bay) pricing policy. The law increased the marketability of Prudhoe Bay gas by averaging (rolling-in) its price with cheaper gas from the lower 48 states. Second, proven gas reserves in the lower 48 states were decreasing at such an
alarming rate that production levels were likely to decline soon. With Prudhoe Bay containing 13 percent of the nation's proven gas reserves and the possibility of yet more gas deposits in the vicinity, constructing a delivery system to U.S. gas markets, it was argued, could largely offset any production decline. Third, the world oil supply situation created favorable economic conditions for the project. Oil supply shortfalls in 1979 and 1980 resulted in oil prices increasing threefold, making Alaskan gas more economically viable sooner, particularly if the trends continued (see Figure 3).

What followed in 1981-1982, however, was a series of energy and financial market developments that resulted in Exxon, the chief participant in the project, withdrawing its support. The withdrawal came just six months after the federal government had enacted yet another law, a set of legal waivers, which further enhanced the financial feasibility of the project in the private sector. The legislation, however, was not enough to offset several market developments which significantly changed the economics of the project.
First, demand for natural gas in the largest U.S. market, the industrial sector, declined 17 percent in 1982. This was a result of economic recession, energy conservation, and switching to fuel oil, whose competitive price was beginning to make inroads, particularly in light of the prevailing U.S. policy of incremental pricing for natural gas. Under this policy, industrial users would pay for the more expensive natural gas delivered and residential users for the less expensive; however, with many industrial gas users having dual-fired capability, they would switch to the cheaper fuel oil. It was projected that switching would be even more accelerated if Alaskan gas, selling at the projected price of $10-15/Mcf, was brought into the marketplace. If massive industrial switching had taken place, residential commercial gas user rates could have skyrocketed.

Second, the outlook for future world oil price behavior changed markedly. In 1982, many experts found themselves in considerable agreement that world oil prices would decrease or remain the same, in real terms, for the rest of the decade. This, when coupled with other factors—a large unused surplus of oil production capacity in OPEC, a U.S. domestic gas surplus, and the belief U.S. energy conservation would continue—led to the conclusion that Alaskan gas would have little or no marketability in the United States for the foreseeable future.

Third, prevailing high interest rates in nominal and real terms essentially sealed the project's fate. Such rates caused the domestic oil and gas industry to favor lower risk investments with fast payback periods. At the same time, U.S. banks became more conservative lenders for oil and gas projects. A prime motivating force for this change was the July 1982 failure of Penn Square Bank, a small Oklahoma City bank that specialized in energy loans. It had syndicated high risk, energy-related loans totaling $2 billion to numerous banks, including some large, well-known U.S. banks specializing in energy finance. The failure to repay these loans resulted in large quarterly losses for the participants, prompting a change in policy.

Reviving ANGTS in Different Form

In the face of conservative investment policy and gloomy oil and gas price-demand prospects, the United States, one area of the world, the Pacific Basin, offers some market potential for Alaskan gas from Prudhoe Bay. In particular, Japan and the Republic of Korea are experiencing increasing demand for energy imports because of sustained growth in their economies which should continue for the rest of the decade. However, competition in these markets will be intense for any natural gas supplier seeking new markets. In Korea, imported coal from such countries as Australia and the United States has been the preferred energy because it is highly economical for Korea's fastest growing sectors, industry and power generation. Japan, the largest LNG importer in the world, currently deals with five different suppliers: Alaska, Brunei, Indonesia, Abu Dhabi, and Malaysia (all, except Malaysia, shown in Figure 4). In the future, LNG destined for the Japanese markets will increase as Indonesia expands its LNG export capability and Australia constructs a new LNG export facility. Canada is also now negotiating with Japan on another LNG project. All this activity comes amid projections that Japanese demand for natural gas will continue to increase during the 1980s—to more than double the 1962 demand figure—but it should be pointed out that these projections are somewhat (about 15 percent) below those estimated only two years ago.

Recently, a new proposal was introduced by the State of Alaska calling for the construction of an infrastate pipeline from Prudhoe Bay to the existing LNG export facility at Kenai (Cook Inlet). The project would expand this facility and attempt to gain market shares in the Pacific Basin not only in natural gas, but also in petrochemicals. The production of petrochemicals would be tailored to the market segment showing the greatest sales possibility. As in future natural gas markets, competition in petrochemical markets will be intense. By the mid-1980s, for example, OPEC nations are projected to expand their capacity to make ethylene and methanol by more than fivefold each.

Figure 4. Main International Gas Movements 1982


Note: Figures are in million tons oil equivalent.
while boosting ammonia capacity about 50 percent. The gain in ammonia will be chiefly from Indonesia, already OPEC’s biggest producer, and Japan’s largest supplier of LNG. In these three products, the most important in the petrochemical industry, OPEC countries have a significant cost advantage because of their access to low cost natural gas and gas liquids. This is why Japan, which continues to seek opportunities to diversify energy supplies, has expressed the most interest in participating in the development of the Prudhoe Bay gas source. The added incentive for Japan is that the agenda of the U.S.-Japan Governmental Working Group studying the feasibility of Alaskan gas exports also includes the issue of Alaska permitting Alaskan crude oil exports, consistently a major interest of Japan’s.

However, with private markets unreceptive to any idea of an ANGTS revival and noncoeval toward the new proposal, any significant break in policy at the government level, either federal, foreign, or state (Alaska), could change the viability of a project in the foreseeable future. When one considers that (1) current U.S. energy policy is primarily based on market forces, (2) permitting Alaskan oil or gas exports would generate political fallout in a U.S. election year, and (3) Japan has access to large, somewhat secure, quantities of natural gas and petrochemicals elsewhere, the possibilites for this project narrow markedly in the short term, at least.

Notes

1. The recommendation that ANGTS secure project financing without federal government guarantees was contained in the presidential report to Congress, “Decision and Report to Congress on the Alaska Natural Gas Transportation System,” which was adopted and enacted into law (P.L. 95-158).


3. Ibid.


Gary J. Pagliano


The papers by Roland Priddle, Keith Palmer, Afzaneh Hashemkhani, and Gary Pagliano persuasively demonstrate that almost universally the pricing of natural gas has been considered by government decision makers to be too important to leave to the market. That seems, however, to be the extent of the agreement. The decision to capture some of the economic rents for either the government or for natural gas users does not carry with it an efficient system for doing so. Given the disappointing experience of the United States with the problem between 1960 and the present, one can hope that others learn from our mistakes how to avoid similar costly ones.

Economic rents and monopoly rents, however, should not be confused, and it is monopoly rents that seem to be a partial source of the conflict between the United States and Canada. Clearly, if a free market for gas existed between the two countries and wellhead prices were market determined in both countries, the economic rents for U.S. gas would accrue to the owners of U.S. wells, and the economic rents from Canadian wells would accrue to the owners of Canadian wells. The Canadian government in such a circumstance would, however, have an alternative which, if the Mexicans would follow suit, could increase economic rents to Canadian producers. The government could impose wellhead or border price controls and recognize that as a residual supplier to the U.S. market it could develop some monopoly power, that is, it could add some monopoly rents to its economic rents. In effect, Canada...
could implement an umbrella pricing scheme on the U.S. market.

If the absolute amount of Canadian exports to the U.S. market is small and/or the U.S. price elasticity for gas is relatively high (in absolute value), then the gains from such a policy would probably not justify the administrative cost and the internal political conflict engendered, but if the exports are large and the U.S. demand relatively inelastic, then the gains to Canada could be very large indeed.

A principal determinant of whether Canadian exports will be large or small is U.S. wellhead pricing policy. If the United States reimposes wellhead price controls, holds down the price of domestic gas, and reduces the incentive of producers to develop new gas supplies, Canada's relative share of the U.S. market will grow, and the opportunity for the Canadians to gain monopoly rents will grow. It is to be expected, then, that the Canadians will not be able to define their own natural gas policy until the United States defines its policies.

I found Priddle's speech encouraging for two reasons. It demonstrated an admirable understanding of the intricacies of U.S. policy making about gas, and it demonstrated an intent to treat the issue of selling gas as an economic issue. I hope the United States can do as well. Clearly, U.S. policies as to who can buy Prudhoe gas show that the United States has not always been able to be so rational.

If the above analysis is correct, it seems that any attempt by the United States to reimpose wellhead price controls in order to capture economic rents for ratepayers is doomed to failure. The rents will merely be transferred to Canadians and/or Mexicans. Consequently, the United States, when setting domestic gas policy, should recognize that transferring economic rents from U.S. producers to ratepayers through the price system is not a viable policy, if imports make up a significant part of the total supply.

I find it encouraging that the World Bank is devoting attention to the problem of pricing wellhead gas in less developed countries, although I must admit some pessimism about the likelihood of any resolution to the problem of reconciling efficiency, administrative simplicity, and the capture of a socially share of the rents for the government or ratepayers if gas is produced by profit-seeking firms.

Still, one must expect that as the world's population increases, the level of pollution, old age intensifies, and the resource base of natural gas is diminished, the issue of economic rents will increase in importance. If rents are a political issue in 1984 when the wellhead price in many countries is less than one dollar per Mcf, one can deduce that they are likely to be of far greater importance when the price becomes ten dollars per Mcf.

These papers by Keith Palmer, Asafiah Mashayekhi, Roland Priddle, and Gary Pagliano on natural gas pricing are a guide to the realities of the human condition. Natural gas is a strange and unusual commodity. As the two World Bank authors point out, it is subject to economies of scale and indivisible lumpy investments. That is, the producer and consumer are irrevocably linked by an allocational cord, by the gas pipeline. They are interwoven in an unavoidable long-run relationship. It is no surprise, then, that principles of competitive markets do not seem to apply. Palmer's paper very ably recites how an economist slanted to a tradition of efficient competitive markets would develop and price natural gas in any country, developed or developing. Gas would be priced at its marginal opportunity cost, and his paper clearly shows why that should be the case. His World Bank colleague Mashayekhi, however, informs us that contrary to Palmer's policy prescription, there seems to be a dominance of gas pricing at average historical cost in both developed and developing countries. Why should this be so? She states clearly that gas prices are not based on the recommendations of economists but on the results of governmental regulations, institutional frameworks, and social and political pressures which differ among countries. She further points out that in the pricing of natural gas, most developed countries are not good examples for the developing countries. There must be something fairly compelling going on. One thing is that gas consumers have a large say in
gas pricing, especially in developing countries where monopoly government-owned industries may be the gas consumers. They obviously want gas priced as low as possible. The World Bank authors point out the political problem in letting private investors, especially private oil companies, reap unregulated profits from gas production. The decision makers must put on a good show of keeping the lid on private profits, hence, cost-based pricing. It must be especially frustrating for World Bank economists to present their cogent and well-reasoned recommendations for marginal cost gas pricing, only to be asked how it is done in developed countries.

Priddle provides a pleasant explanation of how gas pricing has been handled between the United States and Canada. He calls the intervention of the Canadian federal government in the gas contracts between Canadian producers and U.S. gas companies "benign" intervention needed to "smooth the transition" between market conditions. I presume the World Bank economists winced at this explanation. Perhaps Canada should have left the market transition up to the buyers and sellers. In California we certainly did not view the Canadian federal government's unilateral increase in the border price of gas to the United States as benign. But Priddle replies very clearly the political factors that pushed Canada toward such intervention, especially the fact that Western Canadians could not be seen to be selling gas to the United States that was cheaper than the oil western Canadians had to import. I suppose these are the kind of political pressures to which Nashayot referred.

Paglino's paper makes it clear we should be very thankful for one thing, that we buy gas from Canada and not from the Soviet Union. Clearly, the Soviets were extremely efficient bargainers in dealing with Western Europe on the big gas pipeline. The Soviets obtained a very good deal. Now the Western Europeans will have to try to exert market forces on the Soviet gas price, and the renegotiations are likely to be far more painful than the U.S. negotiations with Canada. Yet, the situations are the same. How different things would be if only gas were priced automatically at its long-run marginal opportunity costs, the world over, regardless of political pressures. World economic efficiency and political peace would probably be well served if all international gas pricing were done by the World Bank's Energy Department. Their studies seem sensible and reasonable. But no party in gas production or consumption seems willing to go to formules instead of bargaining. With bargaining, each party has the cherished hope of cutting a better deal than under economically efficient pricing.