Public Utility
Regulation in an
Environment of Change

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will not create opportunity for these small suppliers. By providing an effective counterbalance to the potential dominance by the large, integrated service/CPE providers, the OTCs could be a major outlet for small and medium-sized CPE manufacturers.

The FCC has the ability to permit the OTCs to become viable competitors and bring their particular strengths to meet the needs of government, large business, small business, and residential customers. The elimination of market dominance and better serve the public interest. Competition will develop, and efficiencies will be achieved that will not be realized in a marketplace driven by two competitors.

**Cl-Ill Opportunities**

In the Cl-Ill proceedings currently under way, the FCC has the opportunity to provide the OTCs the relief necessary to ensure the viability of these companies and the development of a truly competitive marketplace. Very simply, two key steps need to be taken: (1) Structural separation must be eliminated as a regulatory tool, and (2) delay in the introduction of new services to the public must be eliminated.

The first step can be accomplished by replacing structural with nonstructural separation mechanisms such as accounting controls and unbundling of CPE services. For example, positive reporting of provisioning intervals for services provided to potential competitors, disclosure of network and customer information to competitors in the same manner as disclosure to CPE unregulated operations, and the establishment of interconnection rates.

The second step can be achieved by avoiding prior review and approval procedures for each new service. If the FCC must satisfy itself that each meets nonstructural requirements, the FCC could undertake postmarket approval procedures.

The FCC must assure that any nonstructural restrictions it imposes will not prevent the OTCs from participating effectively in the CPE market. In granting structural relief to AT&T, the FCC imposed conditions in four areas: accounting, customer information, network information, and network access. It also required AT&T to file marketing and accounting plans. These nonstructural separation mechanisms do not inhibit the ability of AT&T to market its services successfully. Given the limited geographical areas in which the OTCs operate and their lack of vertical integration, the conditions placed on them should be less rigorous, or at least no more rigorous than those placed on AT&T.

Computer Inquiry III can open an era in which the public truly benefits from the resources of the telephone network and the availability of competitive service offerings. The needs of the public dictate an end to structural separation and the avoidance of nonstructural conditions which would serve only to increase prices and cause customer inconvenience.

**Steps in the Right Direction**

The FCC’s recent approval of the Bell Atlantic Prime Contractor Waiver and the Protocol Conversion Waiver are steps in the right direction, but much more is needed. The Cl-Ill Waiver means that the small competitive service providers can seek on a coordinated basis either unbundled service or conversion from their service provider, on equal terms and conditions. The Protocol Conversion Waiver allows for the coordinated provisioning of CPE and Centrex to respond to customer requests for single responsibility and permits Centrex to remain a viable OTC service offering. It is a good short-term emergency response to the needs of the marketplace, but it is not a viable, long-term solution. The waiver prohibits the use of CPE provided by an affiliated company. Customers require supplier control over the particular product line and desire future enhancements and evolutions to be furnished by that supplier. The limitation requiring the use of a nonaffiliated company by Bell Atlantic to provide the CPE will cause customers to question the long-term viability of Bell Atlantic as a supplier.

The Protocol Conversion Waiver represents a major step toward giving the OTCs the opportunity to make the network more valuable to consumers. The FCC has also recently granted additional authority to New Jersey Bell to market protocol conversion on an unseparated basis. This is an excellent example of an improvement to the local network which will lead to its increased utilization in a cost-effective and efficient manner. This also demonstrates that removal of constraints on the OTCs’ capability to compete will promote competition and development in related markets. For example, analysts predict that sales of packet assembler/disassembler (PAD) equipment, necessary for the provisioning of packet switching, will grow at an annual rate of 35-60 percent -- to a $470 million market by 1989 -- because of the relief granted to the OTCs by the FCC.

**Conclusions**

Structural separation is a major inhibitor of a fully competitive, fair telecommunications marketplace, one with more than two competitors.

Large customers require joint planning, marketing, and implementation of integrated systems by a single, responsible supplier. The OTCs must be permitted to meet these needs or risk being excluded from the large business customer marketplace. The consequences of this continuing constraint will be a reduction in the contribution available to support residential local exchange service and the creation of additional pressures for local rate increases.

Allowing the OTCs to compete in the marketplace on a full and fair basis will result in the wider availability
of customer alternatives and will result in availability of services to those consumers who may otherwise not have access to them.

Now is the time to address the competitive balance in the marketplace. The OTCs cannot continue to function as viable competitors to AT&T, IBM, and other well-financed, unrestricted competitors if they must continue to be burdened with artificial regulatory handicaps that add costs to their operation and diminish their ability to satisfy their customers' needs. The freeing of AT&T from structural separation has created an urgent need for OTC relief, as many customers are now considering signing long-term leases with AT&T.

The OTCs do not have the ability to cross-subsidize. The threat of service and facility bypass, regulatory oversight, and the consumer, political, and regulatory pressure to maintain affordable local exchange rates combine to prevent monopoly profits from being earned from either exchange or exchange access services. The OTCs lack any reasonable chance of gaining permanent market advantage due to predatory pricing because the market is now dominated by large, vertically integrated competitors. The public will benefit from the addition of viable competitors who can bring their particular strengths to the market to serve the needs of both large businesses and the mass market of small business and residential consumers. These facts justify speedy abandonment of structural separation.

Regulators, legislators, and others are beginning to see the detrimental effects of these constraints, and change is beginning to take place. Now is certainly the time for prompt and decisive action.

Notes
4. 95 FCC 2d at 1129-30.
5. Comments of the National Telecommunications and Information Administration, In the Matter of Furnishing Customer Premises Equipment by the Bell Operating Companies, RM-5230, pp. 8-9.

7. See Business Week, August 27, 1984, p. 91.
9. AT&T Communications, FCC 85-584, released November 7, 1985 (Megacom); AT&T Communications, FCC 85-583, released November 7, 1985 (SDN).
10. The efforts of Bell Atlantic to reduce the charges for switched access on an interstate basis are well established; see Bell Atlantic's Comments in response to the FCC's Request for Data, Information, and Studies Pertaining to Bypass of the Public Switched Network (May 21, 1984). In the intrastate arena C&P of Maryland has been authorized by the PSC to reduce the carrier common line charge (CCLC) element of switched access charges by 10 percent; C&P of Virginia has been authorized by the SCC to reduce the CCLC by 20 percent; C&P of West Virginia has been authorized by the PSC to reduce the CCLC by 50 percent, and Pennsylvania has been authorized to reduce overall revenues from switched access by $30 million.
11. Bell of Pennsylvania has been authorized by the PUC to reduce toll rates by 10 percent in 1984; Diamond State Telephone was authorized to reduce toll rates in 1985. Bell of Pennsylvania's request to further reduce toll rates by 25 percent was denied by the PUC in 1985, and C&P of Maryland's request to reduce toll rates by $2.6 million was denied in Case Nos. 7450-II and 7735 on 12/30/83.
15. 95 FCC 2d at 1135.

16. See Comments of the National Telecommunications and Information Administration, in the Matter of Furnishing Customer Premises Equipment by the Bell Operating Telephone Companies, RM-5230, p. 12. Bell Atlantic documented customer single-source procurement demands in its petition seeking waiver to permit it to provide Centrex service and CPE on a prime contractor basis. That request was granted in The Bell Atlantic Telephone Companies, Emergency Petition for Limited Waiver of Section 64.702, File No. AAD-500028, Mimeo No. 0358, released October 18, 1985.


23. Waiver of Section No. 64.702 of the Commission's Rules (Computer II), 100 FCC 2d 1057 (1985).

24. Waiver of Section No. 64.702 of the Commission's Rules (Computer II), Mimeo No. 1426, released December 13, 1985.


Comments

Martin T. McCue

As a group, the papers by Gerald Post, Ronald Chouere, Jerry Duvall, and A. Gray Collins tend to emphasize that we are entering an era in which effective nonstructural costing and accounting safeguards, properly applied, are going to be absolutely necessary. These will have the unenviable task of providing the primary "hands-on" regulatory protections for an increasingly complicated telecommunications industry. I am not, however, advocating that they be excessive. Appropriate is a better word.

Technology and competitive marketing will dictate costs and prices more and more in the future. At the same time, regulated costs, which were once thought to be capable of some clean, complete identification, whether by direct assignment or use of an allocator, are entering an area of new murkiness. We cannot let this matter (or the response) get out of hand.

In other words, there will still remain the two fundamental regulatory problems: defining costs and allocating them, however they are defined.

The papers touch on aspects of these points, and all of them underscore how serious these problems will be.

Duvall's paper provides a good background. It shows how the issue of "what regulation is necessary" has evolved from its fundamentals to the current environment, wherein the FCC now seems committed to using mainly nonstructural cost and accounting safeguards for the companies it regulates.

Duvall's discussion implies that the FCC is giving up on some of its rate structure and AT&T/BOC separate subsidiary
regulation because it cannot agree when those tools might be most successful, and because rigid rate structures and AT&T/BOC separate subsidiaries are hard to use in the current marketplace to achieve the broad "universal service," "efficiency," and "pro-competition" goals. As we all know, the FCC has been increasingly faced with difficult individual choices, which require resolution without setting dangerous precedents.

Particularly recommend Duvall's discussion of cost allocation issues. It covers the way costs are defined (and adjusted) by carriers and commissions as well as the strategic advantages that can result. He discusses the limits of efficient and inefficient rate structures.

I see a good deal of marketplace verification of his arguments. Players in both the terminal equipment and inter-exchange markets right now are primarily concerned with marketing and pricing to increase market share. They will likely develop without regard to current profitability. As a result, financial problems are developing for many companies that lack the resources to survive this battle. I view some of the pricing in these markets as uneconomic at this time. Duvall's discussion provides insight into how we might respond when similar uneconomic pricing problems aimed at market share development get to the local loop. To some degree, this has already begun for some local facilities.

I differ slightly with Duvall over what is "structure" and what is "structural" regulation. Structure regulation to me is still microeconomic in the sense that it goes beyond basic rate-of-return regulation of the price of a service, to establish what services are available, who provides one another and then prices to affect one's customer base or competitors. Rate structuring can be used as a defensive means of market protection when costs themselves might not be low enough to let prices be as competitive as one would like. In contrast, structural issues might be more like a macroeconomic market overview. Larger market incentives and dynamics are recognized for what they are and used to advantage. Even with structural regulation, some firms are not large enough to directly compete. I agree with Duvall that this would be possible mainly by firms which are in fact dominant, they are not necessarily the only ones who can do so. Nondominant carriers that are smarter, quicker might create unique advantages and occur in the same way, either temporarily or in more limited areas.

Although they discuss different issues, the Chourea and Post papers effectively outline the reasons cost and accounting realism is so necessary. Chourea gives a good assessment of an existing quagmire. Post describes a future one. A number of fundamental cost and pricing problems were seen five or six years ago in that era of exploding competition as capable of resolution through no other means but an AT&T/BOC separate subsidiary. Today, with a higher degree of competition, that feeling is being offset by a desire for actual delivery of technological efficiencies to the consumer. And as Collins says, the need for maintaining technological superiority in U.S. firms is increasingly apparent. I could not agree more.

The AT&T/BOC separate subsidiary requirement is a powerful tool (although not as powerful as divestiture itself was). Unlike Collins, many believe a separate subsidiary may still be useful as a way to deal with certain issues. After all, the FCC still requires broad separation in areas outside Computer II. Separation in various degrees is simply one way to allow a commission to allow a regulated entity to enter a related or unregulated market. For example, with my own company, geographic and management separation provided a way for us to enter the cable television business. We are now looking at the 25 largest cable operators.

The separate subsidiary requirement may continue to have a role, despite the fact that the weight of opinion now is leaning against it. Most seem to believe that its use should be the exception rather than the rule. I also sense some feeling that "divestiture was enough of a separation." That attitude represents a dangerously simplistic analysis for current regulatory problems, even if a separate subsidiary is not the answer.

The need for more regulatory flexibility, especially more costing and pricing flexibility, is increasingly an issue. In this era, however, one competitor's liberty is another one's license. Collins and Chourea seem to disagree on the boundary between how much latitude is permissible and how much is not. Each has colorable reasons for his concerns about costs. At what point does "price responsiveness" end and "cost manipulation" begin? While there may be some general rules that reasonable companies and regulators agree upon, there are also fundamental disagreements. A single series of pricing activities can be viewed as both inspired and illegal at the same time.

Let me give some examples. Regulators are always under pressure to allow carriers to anticipate and respond to the marketplace, with countervailing pressures to close off opportunities for cost manipulation. This process is a constant balancing act. And, in all of these areas, in addition to license and regulation, there are real but intangible costs that are guessed at, estimated with surrogates, or simply escape through the cracks. Consider these items raised by the papers.

The calculation of NIS costs. I personally believe that the basic NIS allocator has always been somewhat arbitrary, going back to (and even before) Smith v. Illinois. The 25 percent benchmark has been important as the "best guess." Since the early 1980s, whether in the pre-Smith industry, in the "closed door" Ozark discussions of the 1980s
identified by Post, or in the current Joint Board deliberations. The Supreme Court case of Houston v. Southwestern Bell Telephone, 259 US 318 (1921), which was the primary case relied upon by the Supreme Court in Smith, had accepted a flat 25 percent allocator back in the 1920s. However, Smith itself was significantly undercut in MCI v. FCC by the decision upholding the SPF freeze, a case decided in December 1984.

The shift of both TS and NTS costs between the interstate and intrastate jurisdictions. As Choura acknowledges, since divestiture the cooperative efforts of recent Joint Boards have resulted in slow and only minimal revenue shifts between the jurisdictions. This exemplifies real revenue neutrality. Such slow change may not bother those long used to the lack of inertia to respond to competition in the future if the market itself changes significantly. The key to Choura’s paper, to me, is in his attachments 1-5. These cover the proposals for changing the separations treatment of central switching investment. One would think that, as in mathematics, the product A × B × C would be the same as C × B × A. Not so in telecommunications. It makes a significant difference in the separations process whether one looks into their intrastate- interstate segments first, or their TS-NTS segments.

Both the prevalence of mirroring in intra- and interstate rates and the decision to form a new Joint Board to consider altering jurisdictional usage calculations recognize the fluidity and interdependence of jurisdictionally separate markets. Artificial restraints, then, will become tougher to maintain as we look at the new experimental proposals on the definition and recovery of NTS costs in 1986 and thereafter.

There is some contradiction between Choura and Post about the market effect of recent jurisdictional cost shifts. There is also some contradiction between these two people and Collins. Choura’s telephone industry notions encourages this decentralization. Post seems to say no. Maybe in the short run, without a major threat, negotiation is fine. It, however, the changes demanded by technology become major, no amount of jurisdictional negotiations will do the work. At that point, Collins steps in to explain that one is then negotiating with the market, without much bargaining position.

Thus, the potential effect of a major market-driven service of overall local exchange carrier costs could be staggering, if, due to outmoded pricing local carrier service could not be met by a reasonably priced local carrier alternative. For example, AT&T’s Megacom service has the potential to effect up to half the entire switched access MOU demand growth for 1985-1986. While this is only 1-2 percent of the total switched access MOU, the number is still very high. (See footnote 13 of the Memorandum Opinion and Order in docket 85-326, released November 7, 1985, on the

Megacom filing.) Personally, I was astounded that footnote 13 did not get more publicity.

The move toward digitalization. Post underlines fundamental problems with the NTS cost identification process. I can add a few more:

Centel began to go digital in 1978, and more than half the total number of lines served by Centel now are served by host or remote digital offices. This percentage is far higher than that of most BOCs and, indeed, of most of the larger Bell companies. Compare the NYNEX companies. New York Telephone was only one percent digital at year end 1983 and will be only 11 percent digital by April 1986. Other BOCs have similar problems. Digitalization will be self-encouraged in the BOCs over the next few years. Depending orders, however, seem to have temporarily peaked. There is a tremendous amount of room for growth and controversy in deciding what should happen with costs when digitalization actually occurs.

Digitalization itself tends to result in more costs becoming NTS. As seen today, more than 70 percent of the costs of digital offices can be characterized as NTS. NTS cost allocations of digital switches depend on the carriers’ first identification of expected peak demand and the resulting switch engineering by the manufacturer. They depend, as Post said, on the amount of intelligence put in the line cards and other hardware, or the amount of BORSCHT that is fixed. They depend on the nuances of the NTS definition itself. They depend on the changing uses of fundamental switch items, like power. They depend on the costs of intangibles, like software-related labor.

And, coming soon, there may be another wave of NTS cost changes. These will come as (a) the network becomes heavily dependent on software, (b) fully distributed processing spreads the switching function throughout more of the network, and (c) software costs allocations increase.

Unquestionably, COE cost allocations will be increasingly difficult to achieve in a meaningful way in a digital environment. While distributed processing can be much more efficient, it is also almost completely eliminate the idea of traffic sensitivity. The same is true with fiber optics, as it accommodates great amounts of voice, data, broadband, and video services and intelligence itself. Post’s discussion is telling. The most important and most expensive parts of the network are now becoming functionally indistinguishable from computers and LANs. Except for more specialized manufacturing, more detailed software, and greater network integration, computers and communications will have converged. Yet, there is no concept of NTS and IS in the computer world, only memory and speed.

What are the implications? The newly evolving cost, price, and accounting environment will be dangerous for the
regulator, the competitor, the consumer, and, to some degree, the carriers themselves.

There is an increasing amount of freedom for efficient interplay between the regulated and unregulated areas, both between companies and within the same company. This is occurring not only in the use of facilities but also in engineering and marketing new enhancements to the network.

Computer III decision seems sure in 1986, with the separate subsidiary requirement expected to be a reality. However, the new Uniform System of Accounts (USOA), also due in 1986, probably cannot be implemented until at least late 1987. To the extent this new USOA is expected to step into the breach left by the erasure of the AT&T/BOC separate subsidiary requirement, that may not be realistic. Assuming one believes there is an additional regulatory value to the AT&T/BOC separate subsidiary requirement (and Duvall notes correctly that there is), the inability to discern problem areas more rapidly, the new USOA might not be ready to compensate in time.

Apparently, the FCC is also considering the issue of if and how joint and common costs should be measured. Theoretical disagreements on this issue will always divide economists and regulators. Duvall notes a basic one. A fair allocation is not always the same as an efficient allocation. This is considered a major regulatory issue, the resolution of which will probably please only a portion of those affected.

The result is that one can expect more uncertainty and danger in 1986-1987, during another crucial period of competitive development. Even among those who disagree about the value of the AT&T/BOC separate subsidiary and the need for effective costing and accounting, there must be some recognition of a higher regulatory risk. In the separate subsidiary area, the FCC now appears to be suggesting that it will accept this risk equally as it affects competition.

What additional responses may be necessary are not yet clear. They probably would encompass some of the suggestions made by each of these panelists. As Choura notes, cooperation is essential to maintain a competitive and appropriate level of cost accuracy in a Computer III, technologically advanced era.

This commentary has assumed that broad deregulation is not forthcoming soon. Fortunately or not, some market forces may already be altering both the local and the intercity side of the business, although their effect is increasing impure. On the local side, an enormous network remains essential to get to all end-users. The size of that local web is difficult to conceive, much less duplicate. This implies that some regulatory response is appropriate at least for now. But even the local marketplace is different for different customers. Small companies, at least, may be ready for nondominant status, and even large companies may be nondominant in the provision of some services, such as high volume business services. One of Choura's main concerns is to ensure that the fundamental strength of the local network is not diluted through competitive sections. This concern is not limited to regulators, or even to the telephone industry.

We must recognize and balance new technology and the new integrated network, continue to break it down conceptually into realistic ways, and deal with it without stifling its promise.

In the end, regardless of how one engineers a network, its costs ultimately must be lower to stay competitive. Choura expresses some fear of extraordinary investment made only to improve the network, without a net benefit to subscribers. Centel's experience has been a bit different than Choura's fears would predict, and it tends to contradict those fears. At times, we have been looking not to already exist technology for which we see little demand. The actual revenue contribution of data transmission remains a shadow of what was predicted over the last decade. Voice remains the engine upon which the network runs. Thus, there is usually active argument within our companies about whether individual investments and improvements constitute "gold-plating" or whether they make engineering and financial sense without risk. We have elected to make no change in some areas where costs are high, replacing a major regulator still do the job. In other areas, we have found digital conversion is preferable because it is cheaper to install and maintain due to solid state technology and the direct interfaces.

His concerns will remerge when we have to move to IDSN and "internationalize" the network, moving away from the current interim CCITT 56KB U.S. standard to the world standard of 64KB. Choura's concerns also are consistent with concerns expressed by low-cost companies and advocate cost most recently at the 1985 NARUC convention in New York.

One of my own fears all along with the access charge proceeding has been the cost-revealing nature of the process. This is despite what I consider the relatively lean and low cost companies Centel has. I have been concerned that the original predistinction AT&T strategy to put all NTS costs on the end-user will unveil the relatively high costs on a few local networks, encouraging either cost-cutting or more direct connection for customers through bypass services. Some current blueprints for bypass may reflect current relative efficiency, but they still may not be in the highest relative post-Computer III public interest. It will be a challenge to weather the current period of question about
its cost competitiveness by developing unique special arrangements and focusing on quality over price. In the intercity market, such conduct can have more of an effect in limiting competitive losses in areas that are not cost-competitive.

On balance, we must acknowledge that we are never going to get absolute precision in costing or accounting. Nevertheless, we cannot give up. Our methods of cost information gathering must be consistently reviewed, updated and honed as the marketplace changes, but without redefining the fundamental building blocks solely to achieve a pre-intended result.

Duvall identifies a problem in information gathering he calls "asymmetric information flow." It deals with incomplete or one-sided information flow in the regulatory process. I think what may be more dangerous to the recent exercise of the regulatory hand has been the loss of historical perspective, or "institutional history," among the regulators, as turnover has increased. I believe that the information flow problem identified by Duvall actually is getting smaller, at least for issues where the volume of regulatory contacts is not overly one-sided. Collins himself might attest to this. In the 1984 access review process, he saw firsthand as a participant the way in which the FCC was able to force NTEA and local companies to face off directly with AT&T on fundamental cost issues. The FCC could demand justification and adjustment from each party where it felt claims or substantiation were inadequate. The FCC’s best weapons were provided by the parties involved.

While the 1984 discussions were the most obvious exploitation by regulators of this unique leverage over evenly matched adversaries since divestiture, this process has also been used in the 1985 access process to a lesser degree. Similar maneuvering has gone on in the past between high cost and low cost companies in the separations area and will again take place in 1986.

However, one area in which more care will be needed is the negotiation of new NTS percentages, given the new technology. None of the major players can be expected to step back and take a disinterested view. Thus complete information transfer in both directions may not be possible; it also may not be necessary.

We can still get fairness and accuracy in most post-Commerer III cases. However, we cannot let "deregulation" or "the marketplace" become a convenient escape hatch for the inabilty or unwillingness fairly to administer provisions of state or federal communications legislation in a new environment. We are about to begin the first postdivestiture wave: a triun of MFJ costs and benefits. That does not necessarily mean a complete rejection of the current arrangement. It means only a willingness to deal with change honestly.

Part Five
Risk Sharing and Prudence
Tests in Electricity
SYSTEMATIC VERSUS NONSYSTEMATIC
RISK IN ELECTRIC UTILITIES

Ronald W. Melicher and
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The electric utility industry continues to be affected
by financial difficulties associated with the construction
of nuclear power plants. Construction delays and cost overruns
have occurred at a time when electricity demand has slowed
and inflation rates have declined. Some nuclear power plants
which were already under construction have been canceled,
while others have been completed or are nearing completion.
A common question today is: Who should pay for these expensive
power plant decisions -- ratepayers or investors?

There is no simple answer to this complex payment respon-
sibility question. Regulators must decide how to handle
sunk costs associated with canceled plants, and they are
faced with whether to allow very large rate increases when
expensive newly completed plants are placed in utility rate
bases. As a result, many commissions currently are considering
possible risk-sharing proposals such as phase-ins of new
plants over several years so that rate increases are spread
over time. Regulators also are considering the implementation
of prudence tests when evaluating nuclear power plant costs,
with the intention of possible exclusion of "imprudent" costs
from utility rate bases.

Electric utilities involved with the construction of
nuclear power plants have been confronted with three types

Note: The authors wish to acknowledge the computational
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of risk. "Engineering risk" is associated with a new technology in the form of construction errors and the need for frequent design changes. The resulting construction delays, coupled with high inflation rates, often have produced large cost overruns. "Financial risk" is associated with the need to fund large construction expenditures at a time when financing costs were generally very high. This risk exposure has been complicated by the fact that traditional rate-of-return methods for handling plants under construction often have led to a deterioration in the quality of affected utilities' earnings. Finally, "regulatory risk" is caused by the uncertainty surrounding how authorities will handle the costs of large nuclear power plants as they are completed and placed in service, as well as the treatment of sunk costs associated with canceled nuclear plants. These three risks combined can indicate the "nuclear risk exposure" for electric utilities.

This paper focuses on an historical (1959-1984) examination of stock price risk-return relationships for the electric utility industry in an effort to assess the effect of nuclear risk exposure on stock price performance. Utilities were grouped on the basis of nuclear electric companies (no nuclear plants in operation or planned), those with previously completed nuclear power plants, and those with such plants still under construction. We begin with a discussion of traditional rate base, rate-of-return regulation, its application to nuclear power plants under construction, and the resulting "agency" problems or divergent claims between rate payers and investors. This is followed by a description of our research design and electric utility sample. We then discuss our findings concerning stock market reactions to nuclear risk exposure.

**Rate Base/Rate-of-Return Developments**

The Traditional Regulatory Equation

Rate base, rate-of-return regulation has traditionally been expressed in equation form as:

\[ R = E + (V - d)r, \]

where:

- \( R \) = total operating revenues;
- \( E \) = total operating expenses (including depreciation and taxes);
- \( V \) = value of working capital, equipment, and plant facilities;
- \( d \) = accumulated depreciation; and
- \( r \) = allowed rate of return.

A utility's rate base is reflected in the \((V - d)\) term in Equation (1). This dollar rate base multiplied by the allowed "fair" rate-of-return percentage, plus total operating expenses, provides the allowed revenue requirements for the utility. It has been common practice for regulatory authorities to allow utilities to include only completed and operational plants in rate base. Consequently, when new plants are added, rate payers are faced with increases commensurate with higher allowed revenue requirements. Very large rate increases can result when a new power plant is placed in service if the investment is large relative to the utility's existing rate base.

The allowed rate of return \((r)\) should reflect a "fair" rate of return on investors' capital. Economic rationale and legal precedents provide the basis for establishing a fair return within a risk-return capital markets framework, that is, economic theory holds that investors are rational and risk averse and thus expect higher returns on riskier investments. Furthermore, reference is frequently made to the Bluefield and Hope cases in pointing out that a fair return should be commensurate with the ability to maintain existing capital and to attract new capital. Thus, in traditional rate base, rate-of-return regulation applications, investors are entitled to a fair return on their investments commensurate with the returns earned on other investments of comparable risk. At the same time, this does not necessarily imply that investors are entitled to be compensated for managerial inefficiencies at the expense of rate payers.

**AFUDC and CWIP Implications**

Because regulators traditionally have preferred not to include plant construction costs in rate base until a plant has been completed, an allowance for funds used during construction (AFUDC) became the typical way for handling utility plant construction costs during the 1960s and early 1970s. AFUDC is estimated for both debt and equity capital costs and is included as noncash income in the utility's income statement. AFUDC also is capitalized and added to the plant construction costs and becomes part of the utility's rate base when the plant is placed in service. However, as construction and financing costs began rising dramatically during the 1970s, AFUDC became a substantial portion of the reported income of electric utilities. This was particularly true for those engaged in nuclear power plant construction due to both engineering and financial risk complications. Utilities with large amounts of AFUDC relative to cash earnings
In an effort to offset the deteriorating quality of earnings for electric utilities with major construction projects, many regulatory commissions began permitting the inclusion of at least a portion of construction work in progress (CWIP) in rate bases by the latter 1970s. Reuben Phillips (1984) found that regulatory practices for handling AFUDC and CWIP vary widely even today. Of course, to the extent that CWIP was excluded from the rate base or represents a small portion of total construction costs at the time a plant is placed in service, there exists the potential for a large rate shock.

**Nuclear Generation of Electricity**

A U.S. government decision was made during the mid-1950s to encourage private industry to become involved in the production of nuclear power. First, passage of the Atomic Energy Act of 1954 removed restrictions on private funding imposed under the 1946 act. Second, the Price-Anderson Act was passed in 1957 to provide partial government indemnification to absorb possible liability claims in the event of a nuclear disaster involving private industry. According to Luftig and Enholm (1986a), a number of "turnkey" nuclear power plants were built during the early 1960s at fixed prices by manufacturers in order to demonstrate the feasibility of available technology. Since associated losses were absorbed by the manufacturers, initial nuclear power plant cost estimates often were too low. During 1966-1968, more than 60 new reactors were ordered on a cost-plus basis, such that any cost overruns became the responsibility of the participating utilities. Luftig and Enholm (1986a) identified a second major ordering threat during 1970-1974, when plans were made for nearly 150 additional nuclear reactors. Today, more than 80 are in operation.

There have also been numerous nuclear power plant cancellations -- some in the planning stage, others when already under construction. A number of factors have contributed to these decisions. Changes in reactor designs were required as a result of the 1979 accident at Three Mile Island. This and other engineering developments contributed to slowing the licensing process by the Nuclear Regulatory Commission. High inflation and interest rates during the latter 1970s and early 1980s contributed further to the size of construction cost overruns. Finally, demand for electricity has slowed markedly, and nuclear power generation has not developed the cost advantages that were anticipated relative to conventionally powered electric plants.

**Agency Problems and Divergent Claims**

The concept of "agency theory" or agency problems or costs has received increasing attention in the finance literature in recent years. A corporation is a legal entity comprised of various claimants who hold complex explicit and implicit contracts (for example, see Jensen and Meckling [1976]). While the agency term is not commonly used by corporate managers today, they are well versed in the existence of divergent claims on the resources of corporations. Hackett (1985, p. 167) recently stated that "perhaps no clearer illustration of the conflicting objectives of agents of corporations exists than the problems that have beset the electric power industry." One important issue involves who should pay for construction cost overruns and for plants that provide excess electricity generating capacity. Investors (as well as electric utility managers) argue that power plants are constructed to serve the consumers, and, therefore, increases should be allowed to enable investors to earn a fair rate of return on their financial capital. It is argued that excess capacity reduces the likelihood of service interruptions, and if investors are required to absorb construction cost overruns, the ability to raise financial capital in the future will be impeded.

Kahn (1985) also uses an implicit bargain argument between consumers and investors in analyzing who should pay for power plant capacity and cost problems. He contends that a utility, in exchange for a monopoly franchise, agrees to "serve all customers on reasonable terms" while providing investors with returns equal to the market cost of capital. Consequently, investors need to earn the cost of capital on both plant investment successes and failures. Otherwise, investors will earn less than the cost of capital on their overall investments and will stop providing financial capital.

Of course, rate payers reject these arguments. They contend that they already have paid a sufficiently high price for the form of rate increases associated with the higher fuel costs and higher interest rates that occurred during the 1970s. Furthermore, it is argued that rate payers should not have to pay for management inefficiencies and errors, and thus regulators should not allow such "imprudent" costs to be included in utility rate bases. Given these agency problems or divergent claims, it is not surprising that regulatory commissions are now considering possible burden-sharing alternatives in their application of rate base, rate-of-return regulation. We now are ready to turn to the research design and methodology used to examine the stock market reaction to electric utilities faced with nuclear risk exposure.

**Research Design and Methodology**

A recent Merrill Lynch study (Kelly 1983) of electric utilities involved with nuclear power plants divided the industry into three groups: nonnuclear (no nuclear plant
than 100 basis points as of September 1983, then widened dramatically in early 1984, before settling back to about 200 basis points since mid-1984.

The following regression equation was estimated for each utility for each period:

$$R_{jt} = a_j + b_j R_{mt} + e_{jt},$$

(2)

where $R_{jt}$ is the price return in month $t$ for utility $j$, $R_{mt}$ is the "market" price return (based on Standard and Poor's) in month $t$, $a_j$ is the intercept, $b_j$ is the slope, and $e_{jt}$ is a random error term. In a regression model of this form, the intercept term is a measure of relative risk-adjusted performance. In general, a positive intercept indicates superior risk-adjusted performance, while a negative intercept indicates inferior risk-adjusted performance. The slope term, usually referred to as "beta," is an index measure of systematic (or market) risk in that it indicates the responsiveness of a change in a firm's stock price to a change in overall stock market prices. The measure of how well the estimated regression equation fits the data is the $R^2$ statistic.

It is common practice to measure overall or total risk as the dispersion of returns around the mean or average return over some period. Dispersion of returns is typically measured as the variance (or standard deviation). The total variance can be further divided into a systematic (associated with overall stock market movements) and a nonsystematic (associated with firm-specific developments) risk variance component. This breakdown can be measured by making use of the $R^2$ statistic as follows:

$$\sigma^2_{R_j} = \sigma^2_{R_{mt}} + (1 - \sigma^2_{R_{mt}}) \sigma^2_{R_j}.$$  

(3)

In order to examine the risk and return characteristics of utility stocks as a function of both time and the amount of nuclear exposure, estimates of seven variables were compiled for each utility over the same period. These variables are: mean price return ($R_{mt}$), total variance ($\sigma^2_{R_{mt}}$), systematic variance ($\sigma^2_{R_{mt}}$), nonsystematic variance, the regression slope ($b_j$), the regression model ($R^2$), and $R^2$. The estimates are then grouped by period and by nuclear exposure.

To test whether there were significant differences between these groups, the Kruskal-Wallis ($K$-W) nonparametric test was employed. It is designed to determine whether $k$ populations have identical means against the alternative that they do not. The $K$-W test is similar to the analysis of variance (ANOVA) parametric test but does not have to make such stringent assumptions concerning population distributions. As an example, consider the following. For each utility group, several beta estimates will be obtained (28 for Group 1, 11 for Group 2, and 54 for Group 3). These estimates are
then ranked from smallest to largest. The smallest beta is assigned a rank equal to 1, the second smallest a rank equal to 2, and so forth (the largest beta is assigned a rank equal to N). The K-W test statistic equals:

$$T = \frac{12}{N(N+1)} \sum_{i=1}^{k} \frac{\text{rank}(i)^2}{n(i)} - 3(N+1),$$

where rank(i) is the sum of the ranks for group i, n(i) is the number of utilities in group i, k is the number of utility groups, and N is the total number of utilities. The null hypothesis is that the three groups have identical means, against the alternative that they do not. The K-W test statistic is distributed approximately chi-square (for large samples), with k - 1 degrees of freedom.

**Stock Price Risk-Return Findings**

**Comparative Results for the Three Groups**

Table 1 shows the monthly stock price return and risk relationships across the three utility groups for the entire (1969-1984) period. The mean or average monthly returns as well as the variance and systematic and nonsystematic risk measures were multiplied by 100 for presentation purposes. Thus the average monthly stock price return for Group 1 was .243 percent (or a little less than 3 percent per year), compared with a slightly negative .015 percent (a loss of less than .2 percent per year) for Group 3. Somewhat surprising was the average monthly return of .309 percent (approximately 3.7 percent per year) for the 11 utilities in Group 2, which had completed construction of their nuclear plants during our period of study. These average monthly returns differed significantly across the three utility groups at the .01 level.

An examination of the stock price regression results for each utility versus the Standard and Poor's 500 Stock Price Index averaged by utility group is also shown in Table 1. Group 1 (nonnuclear) exhibited a slightly higher risk (beta) than the regression $R^2$ differed significantly across the three groups when analyzing the full fifteen years. The variance or dispersion of monthly stock price returns is often used to indicate the total or overall risk associated with an investment. Notice in Table 1 that Group 3 (plants still under construction) exhibited the greatest variance in average returns in addition to having the poorest average returns. Furthermore, Group 2 was characterized by the highest variance in returns in addition to having the highest mean returns. The nonnuclear utilities (Group 1) exhibited return variances and mean returns closer to the results for Group 2 than for Group 3. Variances in returns were significantly different across the groups at the .05 level.

Table 1 also shows the results after total stock price variance has been divided into the systematic and nonsystematic variance components. Differences in the former across the three groups were significant at the 10 percent level, the highest value for Group 3 and the lowest for Group 2. Differences were even greater in terms of the nonsystematic variance, as indicated by the K-W test statistic being significant at the 5 percent level. Again, electric utilities with nuclear plants under construction (Group 3) were characterized by the largest nonsystematic variance in their stock price returns, whereas those with completed nuclear plants (Group 2) exhibited the smallest.

Tables 2, 3, and 4 show the risk-return relationships across the groups for each five-year subperiod.
Table 2. Risk-Return Relationships by Utility Group, 1969-1974

<table>
<thead>
<tr>
<th>Variable</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>K-W test statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean return</td>
<td>.268</td>
<td>.200</td>
<td>- .546</td>
<td>17.79^b</td>
</tr>
<tr>
<td>Alpha</td>
<td>.003</td>
<td>.001</td>
<td>- .005</td>
<td>22.21^a</td>
</tr>
<tr>
<td>Beta</td>
<td>.598</td>
<td>.590</td>
<td>.631</td>
<td>1.96</td>
</tr>
<tr>
<td>Variance</td>
<td>.203</td>
<td>.196</td>
<td>.206</td>
<td>.63</td>
</tr>
<tr>
<td>Total variance</td>
<td>.379</td>
<td>.400</td>
<td>.414</td>
<td>4.88^b</td>
</tr>
<tr>
<td>Systematic var.</td>
<td>.077</td>
<td>.081</td>
<td>.087</td>
<td>2.01</td>
</tr>
<tr>
<td>Nonsystematic var.</td>
<td>.302</td>
<td>.318</td>
<td>.357</td>
<td>3.97</td>
</tr>
</tbody>
</table>

Note: See Table 1 notes.

^bSignificant at the 10 percent level.

^aSignificant at the one percent level.

Table 3. Risk-Return Relationships by Utility Group, 1974-1979

<table>
<thead>
<tr>
<th>Variable</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>K-W test statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean return</td>
<td>.039</td>
<td>- .727</td>
<td>.020</td>
<td>.97</td>
</tr>
<tr>
<td>Alpha</td>
<td>.004</td>
<td>- .003</td>
<td>.012</td>
<td>.84</td>
</tr>
<tr>
<td>Beta</td>
<td>.599</td>
<td>.542</td>
<td>.707</td>
<td>7.73^b</td>
</tr>
<tr>
<td>R^2</td>
<td>.241</td>
<td>.171</td>
<td>.296</td>
<td>11.40^b</td>
</tr>
<tr>
<td>Total variance</td>
<td>.364</td>
<td>.390</td>
<td>.381</td>
<td>.73</td>
</tr>
<tr>
<td>Systematic var.</td>
<td>.088</td>
<td>.064</td>
<td>.100</td>
<td>7.70^a</td>
</tr>
<tr>
<td>Nonsystematic var.</td>
<td>.276</td>
<td>.326</td>
<td>.281</td>
<td>.04</td>
</tr>
</tbody>
</table>

Note: See Table 1 notes.

^aSignificant at the 5 percent level.

^bSignificant at the one percent level.

1969-1974, as shown in Table 2, Group 2 had positive average monthly stock price returns. In contrast, both the nonnuclear group and utilities with large nuclear risk exposure (Group 3) had substantial negative returns. Total variance also was largest for Group 3 and differed significantly at the 10 percent level. However, no significant differences were observable for either systematic or nonsystematic variance measures.

Table 3 shows risk-return results for the latter 1970s (1974-1979). No significant difference in mean returns was observed across the three groups, although the average returns were negative for Group 2 and positive for Groups 1 and 3 (the opposite of the findings for the first part of the decade). However, significant differences in the index of systematic risk measure (beta) and the R^2 statistics were observed. The monthly stock price returns for Group 3 were being determined more by general stock market movements, as indicated by an average beta of .707 (the market beta is 1.00) and an average R^2 of .256 (approximately 26 percent of the utilities' stock price movements were explained by market movements). This deviation from Group 1 and Group 2 by utilities with high nuclear risk exposure also shows up in terms of the significant difference in systematic variance.

Table 4 shows the comparative results for the early 1980s (1979-1984). Mean returns were substantially higher for the nonnuclear utilities (monthly stock price returns of .586 percent, with annual returns approximating 7 percent) and for those with completed nuclear power plants (.773 average per month, more than 9 percent annually). Although positive, the stock price returns for the utilities with high nuclear risk exposure averaged less than one percent per year (that is, 2.03 times 12). Furthermore, the overall variance in stock price returns differed significantly across the three groups during the early 1980s, with the total variance being substantially greater for Group 3. These utilities were characterized by higher average levels of both systematic and nonsystematic variance, but only the latter differed significantly across the three groups at the 5 percent level. Thus, in recent years, utilities with high nuclear risk exposure have been characterized by relatively low stock price returns and relatively high variability in returns when compared to other electric utilities.

Comparative Results across Periods

In addition to examining risk-return relationships across the three utility groups, possible relationship changes were examined across three five-year periods. Table 5 shows the results for all 93 utilities. Period 1 covers 1969-1974, period 2 represents 1974-1979, and period 3 is 1979-1984. Notice that when all the utilities are considered, substantial
negative mean stock price returns occurred during the early 1970s. The average returns were still negative but smaller during the latter part of the decade before turning positive (monthly stock price returns of .298 percent or about 3.5 percent per year) during the early 1980s. In addition to the significant difference in average returns over the total (1969-1984) period, both beta estimates and $R^2$ statistics also differed significantly. Betas increased during the 1970s before falling substantially during the first part of the 1980s, a development accompanied by a similar pattern in the $R^2$. In general, electric utilities were less affected by overall market movements in recent years. The dramatic declines in both interest and inflation rates seem to have had a relatively greater effect on electric utility stock prices.

The total variance in electric utility stock prices actually declined between 1969 and 1984 according to the results presented in Table 5. This significant difference in total variance over time was due primarily to the change in systematic variance, which fell dramatically during the early 1980s.

Possible differences across the three periods for each of the groups also were examined. For purposes of clarity, selected results are illustrated graphically. Figure 1 shows the mean monthly stock price returns for each utility group by period. The nonnuclear utilities (Group 1) were characterized by increasing stock price returns, from a negative level during the early 1970s to positive returns during the early 1980s. Group 2 suffered during the latter 1970s before returning to the highest relative level of returns during the first part of the 1980s. Group 3 lagged substantially behind the other two groups in average stock price returns in recent years. The Kruskal-Wallis test statistics were significant for each group across the three periods at the .01 level.

Figure 2 shows the total variance in stock price returns for each group over the three periods. Notice that overall risk declined sharply for Groups 1 and 2 during the early 1980s, while overall stock price risk remained at high levels for Group 3. However, these visual results are somewhat tempered by the fact that the K-W test statistics were not significantly different across periods for any of the groups.

Figure 3 presents the results for the nonsystematic variance calculations. Notice that this remained relatively level for Group 1 throughout the period. Group 2 was charac-
terized by a decline in nonsystematic variance between the late 1970s and early 1980s. Although not a significant decline, possibly this change is associated with less uncertainty on the part of investors once nuclear plants are placed in service and regulatory decisions have been rendered. Nonsystematic variance for the utilities with continued high nuclear risk exposure declined during the latter 1970s before rising during recent years. This change was significant at the 10 percent level and might reflect continued uncertainty due to regulatory risk.

Summary and Conclusions

The traditionally homogeneous electric utility industry seems to have been separated into several distinct sectors in recent years. Utilities with no previous or planned involvement in the construction of nuclear power plants, the nonnuclear utilities, form one group. Some utilities have completed all of their planned nuclear plants. Another group still has plants under construction. Those utilities which continue to have nuclear plants under construction have high nuclear risk exposure as reflected in engineering, financial, and regulatory risk.

This study divided the industry into the three groups defined above in order to examine risk-return stock price performance from 1969 through 1984. Group 3, with high nuclear risk exposure, was characterized by significantly lower average stock price returns over the total period (particularly during 1979-1984) when compared to the other two groups. Group 3
had significantly higher stock price return risk, primarily during 1979-1984, as measured by the total variance in returns. Nonsystematic variance also was greater for utilities with nuclear plants under construction relative to nonnuclear utilities (Group 1) and those with completed nuclear plants (Group 2).

These findings suggest that nonnuclear utilities and those with completed nuclear plants realized superior stock price risk-return performances in recent years relative to utilities with high nuclear risk exposure. This was likely due to continued engineering, financial, and regulatory risk concerns. The latter seems particularly important today because of the uncertainties surrounding how authorities will handle sunk costs associated with canceled nuclear plants, as well as expensive nuclear plants that are about to be placed into service. The prospect of risk-sharing plans and prudence tests undoubtedly adds to the perceived degree of regulatory risk in the eyes of investors. Of course, the finding of lower risk-return stock price performance relationships for utilities with high nuclear risk exposure does not answer the question of who should pay for nuclear power plants—rate payers or investors.

Notes
1. For a further discussion of risk and return considerations under regulation, see Melicher (1979b).

2. A revised form of government indemnification continues today. For further elaboration, see Melicher (1975, 1976) and Melicher and Mrister (1985).

3. For a detailed discussion of agency theory, see Jensen and Smith (1986).

4. A previous study by Pettway (1978), however, showed that price returns and total returns (price changes and dividends) were highly correlated for electric utilities.

5. The comparison of risk-return performance for Group 3 between 1969-1974 and 1974-1979 should be viewed with caution because Consolidated Edison (a member of Group 3) eliminated its cash dividend in early 1974. This "dividend shock" apparently affected the whole industry for some time (for example, see Pettway [1978] and Melicher [1979b]).
Appendix

Companies Involved in Nuclear Construction

1. American Electric Power
2. Arizona Public Service
3. Atlantic City Electric
4. Carolina Power & Light
5. Central Maine Power & Light
6. Central Maine Public Service
7. Cleveland Electric Illuminating
8. Commonwealth Edison
9. Consumers Power
10. Connecticut Light & Power
11. Duke Power
12. El Paso Electric
13. Exelon
14. FirstEnergy
15. Florida Power & Light
16. Georgia Power
17. Idaho Power
18. Idaho Power & Light
19. Indiana Utility & Light
20. Iowa Electric
21. Kansas City Power & Light
22. Kansas Gas & Electric
23. Kentucky Utilities
24. Long Island Lighting
25. Public Service of New Hampshire
26. Public Service of New Jersey
27. Public Service of Northern Colorado
28. Pacific Gas & Electric
29. Pennsylvania Electric
30. Pennsylvania Power & Light
31. Philadelphia Electric
32. Public Service of Ohio
33. Public Service of Pennsylvania
34. Public Service of Southern California
35. Publius Utilities
36. Puget Sound Power & Light
37. Reliant Energy
38. Rochester Gas & Electric
39. South Carolina Electric & Gas
40. South Carolina Public Service Company
41. Southern Company
42. Tennessee River Authority
43. Texas Utilities
44. United Illuminating
45. Virginia Electric & Power
46. Washington Gas Light
47. Wisconsin Electric Power

References


RISK SHARING AND LARGE-SCALE INVESTMENT

George A. Avery

Shortly after the Three Mile Island accident, I was inadvertently drawn into the controversy surrounding that memorable disaster. I had agreed to give a paper on the response to the accident at a ratemaking symposium and subsequently ended up appearing as a witness before both the Pennsylvania and New Jersey commissions in GPE rate proceedings on the policy questions involved. The experience piqued my interest in the whole question of risk allocation in the ratemaking process, and I have tried since to pay some attention to its treatment in various contexts. Increasingly in recent years, I have found the subject to be of more than academic interest in my own professional concerns, since these risk allocation issues have repeatedly emerged in matters on which I have been directly engaged.

It is, of course, accepted wisdom that public utilities are low risk enterprises compared with firms in the competitive sphere. Utilities, it is said, operate as natural monopolies and are not subject to the competitive market forces faced in other fields; they are subject to a system of regulation which allows them the opportunity to recover their cost of service, including a fair return on their investment. It is certainly a fact that the returns allowed and earned in the regulated environment are substantially less than those found among nonutility industrial concerns -- at least among successful ones.

Yet, when one considers the matter carefully, it is quite apparent that the possibility of very substantial risks
exists within each of the utility industries. These inhere, first, in the huge aggregations of capital investment required to provide their essential services. That capital investment is exposed to a number of risks. First, in the electric industry, the construction period for a single unit often stretches over ten to twelve years before any output can be provided, during which time billions of dollars sometimes are invested. The uncertainties thus created are enormous, and will vary from site to site involving sums of such a magnitude that events rendering those sums unproductive or the facilities in which they are invested wholly or partially unusable can have staggering consequences. Moreover, sometimes such equipment and the utility, because it provides an essential service, has the obligation to proceed with investment for required capacity through any and all financial and economic conditions. Finally, the market for the products and services sold by utilities is subject to many of the uncertainties which tend to respond by applying traditional rate-making concepts and theories to achieve results which they consider acceptable to ratepayers. My thesis is that something deeper is going on and that rational decision making would be aided by a clear understanding of the issues and of possible alternative resolutions.

Each rate case involving one of these plants tends to be perceived by the company, the ratepayer, and the regulatory commission as a discrete event. However, the problems of these nuclear plants can also be viewed in a broader industry perspective, and I think it is useful to do so.

Salomon Brothers has published two reports on these nuclear construction rate cases which provide a useful data base for presenting such an overview. Those reports indicate that there are 38 utilities building 33 nuclear units, 28 scheduled for completion by the end of 1987 and the rest expected to be cancelled. The total cost of the 28 plants is $92 billion. Obviously, not all of this amount will be subject to a prudence disallowance, but I have heard it said that as much as $40 billion is at risk. This is an enormous amount, and it venture to say that no other country in the world could ever stand the burden of rendering an investment so large unproductive to its investors. It seems to me that the very existence of real and identifiable risk of this size, particularly when coupled with actual disallowance rulings amounting to billions of dollars, carries the potential for real and fundamental change in the economic and legal environment in which utilities have existed.

What fundamental changes might bring about this change? It is certainly not possible within this paper to provide a comprehensive analysis, and so I will offer some general observations and draw some conclusions.

Beyond doubt, staggering sums have been invested in facilities whose basic economics are difficult to justify

By prudence cases I mean those rate making proceedings in which a utility faces the possibility that an imprudence disallowance will be applied to some portion of its investment in a new facility. This is a factual situation which has grown in prominence and concern during the last few years. A number of nuclear plants have approached completion at costs substantially higher than expected. In some instances, with pretax reserve levels significantly higher than established norms. In these circumstances, utilities and regulators face the prospect of rate increase requests substantially higher than the current rate of inflation. Understandably, companies and executives which perceive traditional rate-making concepts and theories to achieve results which they consider acceptable to ratepayers. My thesis is that something deeper is going on and that rational decision making would be aided by a clear understanding of the issues and of possible alternative resolutions.
in today's conditions. These plants are being completed at costs which cause their busbar power cost to be at levels requiring rate increases significantly exceeding the rate of inflation. In some cases, the capacity brought on line will not be fully required for many years.

I do not exclude the possibility that there may be instances in which these conditions are, at least, in some measure, the product of management decisions that deserve to be condemned and called to the attention of the public. Such situations are so widespread throughout the industry and the nation that one would have to postulate a mass attack of irrationality to justify a conclusion that this nuclear power problem is simply the product of incompetent utility management.

Other fundamental causes at work are not hard to identify. Under the best of circumstances, construction of these facilities requires extremely long lead times. The period in which construction of the facilities we are discussing took place was one of extraordinary volatility and change in costs of the energy markets. That volatility and change have produced growth patterns for the electric power industry entirely different from those experienced historically by utilities. They have also greatly reduced the ability of utility management to make reliable predictions and assumptions about fuel price trends and comparisons. Government energy policy in general, and regulatory policy on nuclear plants in particular, has introduced sweeping fluctuations and changes in responses to such events as the Brown's Ferry fire and the TMI accident have required additional investment in nuclear facilities of extraordinary magnitude. High inflation rates and monetary costs prevailed during much of the period in which these plants were being constructed. Public sentiment for nuclear power in general has undergone radical changes.

All these factors and others have played a role in creating the specific situation in which each utility now completing a nuclear facility finds itself, and have personally observed this to be so in a number of cases in which I have been directly involved, and I conclude intuitively that it has affected others.

This combination of factors can be described as creating a condition of risk -- and fairly high risk -- in which these plants have been built. Utility management has a responsibility to be aware of and respond to this risk. However, in assessing that response, two facts should be clearly recognized: (1) it is beyond the power of any specific utility management fully to control and manage that risk; and (2) allocating all of that risk to investors profoundly alters the nature of utility investment.

It is this perception which I think must be fostered and encouraged in the ratemaking context, in the interest not of protecting utility management but of providing ratepayers with the assurance of adequate and reliable service at the lowest possible cost. The regulator encounters the problem in the context of a rate case -- or an independent prudence inquiry as a prelude to a rate case -- in which it must be decided whether to include in rate base a large investment with resultant high fixed costs for many years. Since the legal and procedural framework is adversarial, the regulator hears vigorous allegations that responsibility should be laid at the feet of management, which controlled the decisions and not imposed on ratepayers. Regulators are told to decide the issue by applying legal standards such as "used and useful" and "prudent investment" which clearly and properly imply protection of the ratepayer interest, but which must be fleeter on foot in a context very different from that in which those standards were created. Often the decision is made in a highly charged political atmosphere in which elected officials have staked out basically antitrust positions. These conditions can produce decisions which may have relatively little extending beyond the confines of the particular cases involved.

What has happened thus far as these proceedings have unfolded? Substantial disallowances, in some cases involving a billion dollars or more, have been adopted or agreed to. Prudence reviews are under way in a number of states in which the prospect of substantial disallowances exists. A sub-industry of prudence consultants has sprung up and is prospering mightily. Methodologies for assessing prudence and measuring the dollar effects of imprudence which facilitate disallowance have been created and are gaining credence and currency. A clear tendency to impose the risks associated with these projects upon investors is emerging.

In addressing the implications of these results, I will discuss three other areas in which similar risk allocations have occurred.

**Plant Abandonments**

I have been discussing the ratemaking problems presented by a nuclear project. However, the three factors already mentioned -- enormous investment, the lengthy period when changing economic or regulatory conditions -- are also involved in abandoned plant. The question is a straightforward one of risk allocation: Should the risk of noncompletion be borne by the ratepayers, the investors, or both?

Historical precedent once provided a fairly clear answer to the question. If a utility's decision to build a plant was found to have been prudent, most commissions permitted the utility to recover its investment in abandoned plant through amortization charges. This policy developed when gas manufacturing plants were being abandoned in favor of natural gas pipelines, and buses were replacing trolleys.
in more recent times, the stakes have become higher because the burden of noncompliance -- when that burden becomes reality -- can be much greater. In these circumstances, the previously clear answer is becoming murky.

Although the FERC allows recovery if the investment in the plant was prudent, the state commissions have denied any recovery in abandoned plant, regardless of whether the investment was prudent. In 1984, for example, the New Hampshire Supreme Court held that a statutory proviso prohibiting utility rate increases for construction work not yet complete necessarily barred the recovery of investment in an abandoned plant. In Indiana, the state supreme court affirmed a lower appellate court ruling which reversed an order of the Public Service Commission of Indiana permitting a utility to recover the costs of an abandoned nuclear generating plant. The court noted that Idaho’s ratemaking statutes imposed a “used and useful” standard on the commission and concluded that the recovery of those costs was not envisioned in the state’s rate-making laws. The court added that the commission could not recover its share of the investment in the unrecovered portion, where the plant construction had received commission approval and was abandoned due to changes in demand forecasts.

In contrast to the Indiana court rulings, the Missouri supreme court held that the Missouri Public Service Commission had erred in denying recovery to the Union Electric Company for its investment in an abandoned nuclear power plant. The commission had based its decision on a statutory provision that prohibited utilities from levying charges for any cost “associated with owning, operating or holding any property before it is fully operational and used for service.” The court noted that if the provision in question were to mandate forfeiture of abandoned construction, significant problems would arise: If the abandonment was by state mandate, there was no place to place their money in ventures characterized by controlled returns and substantial risks of loss, while the utilities themselves would be reluctant to embark on new construction projects. It concluded that the provision was concerned with the timing of the recovery of construction expenditures, not with abandonment, and remanded the case to the commission for a determination of whether the expenditures incurred on the project and the decision to abandon it were prudent.

Commissions have also approached the question of ratemaking in different ways. In the case of a utility’s ongoing decision to continue building a plant, even though the original decision to construct the plant was prudent. For example, the Idaho Public Utilities Commission, which in 1976 denied Idaho Power Company’s application to build a coal-fired plant because of environmental concerns, in 1984 denied recovery of costs incurred on the project after the date of the public hearings where the utility was formally notified of environmental opposition to its plans. Similarly, the Washington Utilities and Transportation Commission denied recovery of costs incurred on the Skagit/Hanford nuclear project after June 1980, at which time a cost-effectiveness study would have shown the futility of continuing at the site. Although it did not permit the Puget Sound Power and Light Company to recover all of its expenses on the project, the commission specifically noted that amortization of extraordinary loss exposure from a time of positive effect of the loss to the particular utility and its customers. In contrast, if that loss were held to be an investment risk, the negative effect would expand and affect all utilities because investors would add a risk premium to the rate base.

The Wyoming supreme court took a somewhat different approach when it affirmed a trial court decision upholding the state commission’s determination that the Pacific Power and Light Company had not incurred any portion of the investment in the Puget Sound nuclear power facilities. Although the commission had based its decision on the fact that the projects were not used and useful, the court noted that the commissioners wanted Pacific Power and Light to bear the loss because the investment decision was made by its representatives, who had an opportunity to evaluate the attendant risks. If the utility gauged the risk of proposed ventures with the expectation that loss of ratepayer money might bankrupt it, it might venture into activities having little chance of success. The court then observed that the commission was the only entity in a position to balance the interests of all the utility and consumer considerations. In contrast, the state legislature had imposed a requirement on the commencement of a risky endeavor. Thus, although state law did not require commission approval of the project, the court stated that the decision to participate in the terminated projects, such prior approval -- not obtained in this case -- was necessary if the utility wished to have ratepayers bear some part of the loss.

Finally, while some states have been interpreting existing standards for recovering investment in abandoned facilities, others have been developing new ones. For example, the Massachusetts Department of Public Utilities decided that the prudence standard required ratepayers to bear too much of the risk of uneconomic utility investments, and it abandoned that standard in favor of a “used and useful” test. The department’s ruling, which prohibits recovery of any funds spent on plants begun after July 31, 1984, and subsequently abandoned, places the entire burden of noncompliance on investors. More recently, the department reiterated its determination to apply the used and useful standard in the future.

When commissions have permitted some recovery for abandoned plant investment, there has been a tendency to place...
limits on such recovery. For example, among those commissions allowing recovery of the utility's original investment in the cancelled plant, there exists a wide range of policies concerning the recovery of capital costs incurred during the construction period. Thus, while some states permit recovery of all AFUDC amounts accrued prior to cancellation, others allow only that portion of AFUDC attributable to debt capital, and still others deny recovery of any AFUDC.

Another issue that has repeatedly arisen in those abandonment cases where recovery is sought is whether the unamortized balance should be allowed in the rate base, thus permitting full recovery by the utility's investors. Many commissions have refused to include the unamortized portion in the rate base, relying on the rationale that the abandoned plant is not "used or useful," or that investors and shareholders should share the risk of abandonment. Thus, the Connecticut Department of Public Utility Control denied the United Illuminating Company's request to earn an interest and debt return on the unamortized portion of its investment in Seabrook Unit 2.

The department observed that unamortized balances of cancelled plant have never been afforded rate base treatment in Connecticut and concluded that its approach equitably allocated costs between ratepayers and stockholders. The Massachusetts Department of Public Utilities also refused to allow the recovery of carrying charges on the unamortized portion of an abandoned investment, noting that a contrary result would have the effect of allowing the utility to earn a return on that investment.

**Excess Capacity**

Plant abandonment is not the only area in which the risks associated with utility plant investment have increased. Due to high energy costs and other factors, many utilities have found themselves with substantial excess capacity. The treatment of the investment involved has brought confusion in rate proceedings. Again, these cases actually involve questions of risk allocation, the risk being one of market change in industries characterized by heavy fixed investment in plant capacity and long schedules for rate cases and rate cases.

Because plants are generally abandoned in response to reduced demand, one would expect the regulators' approaches to excess capacity to parallel their policies on abandoned plants. Indeed, some similarities exist. In both cases, commissions have often considered whether the original decisions to build the capacity were prudent. This was, for example, the focus of the Idaho Public Service Commission last year when it concluded that 90 percent of the cost of a new plant could be included in rate base, even though the facility had become unnecessary in the short run. Similarly, when load forecasting proved imprudent caused GuF Power Company to purchase a portion of a coal-fired generating unit, the Florida Public Service Commission in its $3.5 million in additional revenue to the utility to reflect the excess capacity resulting from the purchase. The commission's decision was affirmed by the state supreme court.

There is, however, an important difference between abandonment and excess capacity: Although it is usually obvious when a plant is abandoned, it is much more difficult to determine what portion of a utility's capacity is excess. Moreover, utilities must maintain excess capacity in the event of breakdowns, and it is difficult to maintain any predetermined level of excess capacity when efficient capacity often comes in large increments.

This inability to determine precisely when capacity is excessive may have affected regulatory attitudes toward recovery of capacity costs. For example, in Indiana, where, as I noted earlier, the courts had taken a hard line on recovery of capacity costs for abandoned plants, a report held the Indiana commission did not err in finding excess capacity to be "used and useful" and including it in the rate base. Although the investment in question would temporarily yield a reserve capacity of 47 percent, increased demand was expected to reduce that figure to 27 percent by 1986. The court observed that the temporary excess was offset by both stability of supply and economics of scale, and that the commission was not required to set a maximum level of reserve capacity against which requests for rate relief would be measured. In July 1985, the Indiana commission followed the same line, rejecting arguments that Northern Indiana Public Service Company should not be permitted to include in its rate base a recently completed coal plant.

Yet, there have been decisions which penalized utilities for the existence of excess capacity even though the decisions leading to the situation were prudent. One example is found in a series of decisions by the Pennsylvania commission in 1976. The commission found that the Pennsylvania Power & Light Company's completion of its Susquehanna Units 1 and 2.08 An intermediate approach was taken by the Iowa commission when it decided to decrease a utility's return on excess capacity; that is, the rate at which the return was disallowed accelerated as the level of excess capacity increased. The supreme court of Iowa upheld the commission's decision, noting that the utility's shareholders were not insulated from the consequences of a decision that was prudent when made but that turned out to be mistaken.

**Accidents and Other Casualty Losses**

The most obvious example of risk allocation in ratemaking is the treatment of accident-related costs. Generally, when the costs of an accident are within normally expected limits,
all or most are borne by ratepayers. A relatively brief amortization period often is established, but the unamortized balance is now allowed in the rate base. Insurance costs, which spread these risks across a larger universe, are invariably allowed as a legitimate cost of service.

Commitment to the provision of risk to ratepayers has wavered, however, when a major accident, with a substantial potential effect on rates, has occurred. The Three Mile Island accident immediately leaps to mind. Here, the state commissions involved responded to a dramatic problem in risk allocation by dividing the burden between ratepayers and investors, with a very substantial portion falling on the latter. While ratepayers have been absorbing the cost of replacement power, no recovery of the capital costs of the damaged reactor, TMI-2, and the component TMI-1 (which was being refueled when the accident occurred), has been allowed. The Pennsylvania and New Jersey commissions framed their decisions on these issues in traditional ratemaking terms, expressing such matters as the "used and useful" nature of the damaged reactor and expressing an interest in issues of fault. In fact, what they decided was that investors must accept the risk of a major capital loss arising from an unforeseen accident.

The New Jersey commission recognized, however, that its purpose was to ensure a safe and adequate power supply for the ratepayers, and it granted Jersey Central Power and Light Company the highest cost of equity theretofore allowed by any utility in the state. Subsequently, the board also assessed certain decontamination charges to ratepayers, a decision upheld by the state court.

In Pennsylvania, the commission's decision to exclude the capital cost and operating costs of the damaged reactor were upheld in 1983. The court noted that the commission's conclusion that TMI-1 was not used and useful reflected a balancing of consumer and investor interests.

The Role of Risk Allocation in Ratemaking

It is not the purpose of this paper to survey all the current cases in the various ratemaking contexts involving risk allocation questions. As discussed here could be identified. Even as concerns imprudence disallowance, abandonment, excess capacity, and accidents there are many more cases than those included here. Nevertheless, enough ground has been covered to turn to some analysis and conclusions.

Two propositions emerge from the imprudence disallowance, abandonment, excess capacity, and accident cases: (1) while commission frequently deal with the problem of risk allocation, they less frequently recognize and discuss the issues in those explicit terms; and (2) there is a clear tendency, as larger risks emerge, to place the burden of those risks on investors.

The two propositions just stated should be recognized and explicitly addressed in ratemaking decisions for two reasons. First, a clear recognition of the nature of the decision made may lead to a more reasoned and desirable result than is achieved by the simple application of established legal aphorisms such as "reasonable and prudent investment" or "used and useful property." Second, clear recognition of these propositions may avoid unintended results, both for ratepayers and for investors.

In other words, it must be recognized that the issue is not simply whether a decision to invest in a plant that either is now approaching completion at a higher than anticipated cost or must now be abandoned was prudent, or whether some excess capacity is used or useful. Rather, at issue is where certain risks should be imposed. With this clearly in mind, it becomes possible to ask some highly pertinent questions: Which result will produce the lowest long-run cost to ratepayers? What will be the result of the decision on particular elements of cost? These questions, in turn, lead to recognition of some important principles.

Although too frequently ignored by commissions and laymen alike, it is a fact that the ratepayers ultimately will bear all costs associated with supplying regulated services. Commissions often speak in terms of allocating certain costs between investors and ratepayers. Any risk-related cost should be allocated to ratepayers, however, are going to find their way back to the ratepayers in some form or other, because the market compels commissions to provide investors with returns commensurate with those they could receive elsewhere. If returns to investors are insufficient to cover the risks involved because the commission has "allocated" certain risks to shareholders, investors will simply demand a higher return on their investment. As the perceived risk of investing in utilities rises, utilities will be forced to pay higher capital costs to attract the capital they must have in order to meet their responsibility to provide service. The very substantial increase in perceived risk stemming from the imprudence disallowance cases may create lasting effects on the costs of the utilities involved and for others. The very fact that investment firms such as Salomon Brothers deem it useful and appropriate to examine these cases in detail in a series of reports indicates a substantial heightening of investor concern which can eventually have an effect on capital costs.

A second and less obvious way that risks nominally allocated to investors will eventually result in higher costs for ratepayers is through less efficient operations: Utilities will be pressed by shifting operations to less risky but higher cost processes, or to processes where ratepayers assume more
of the risks. For example, if ratepayers bear the full cost of excess capacity but only a portion of the costs of abandoned plants, utilities will tend to complete projects that are not warranted by future demand.

Indeed, this incentive toward less efficient operations through shifting risks to ratepayers may even take the extreme form of discouraging any investment whatsoever in new facilities. As I noted earlier, the courts of Indiana have imposed upon investors the abandonment costs of the cancelled Baily plant. After the initial appellate court decision reversing the commission's allowance of those costs, the shareholders of Public Service Company of Indiana, which has a similar but unresolved issue concerning its investment in the abandoned Marble Hill plant, voted overwhelmingly to adopt a resolution that future investment in new facilities will not be permitted until the state adopts a policy assuring recovery of investment in previously approved new facilities. The Indiana legislature responded by adopting a statute providing such assurances prospectively, and it remains to be seen what future patterns of investment in Indiana will be. Meanwhile, in New York, Governor Cuomo has taken a tack directly opposite to that adopted in Indiana. He has recommended adoption of a statute directly precluding recovery of investment in abandoned nuclear plants.

In this context of shifting risk allocations, the problem of investment in new plant is not confined to Indiana. In October 1985, NERC (the North American Electric Reliability Council) published a forecast that reliability of the nation's supply of power would decline over the next ten years due to the lack of investment in new facilities while existing plants are aging. NERC's forecast specifically ascribed this trend toward lack of investment to the large financial risks involved and observed that it was consistent with most regulatory mandates.

In raising these risk allocation considerations, I do not wish to say that the ratemaking process should seek to impose all risks directly upon ratepayers. Investors will of a sound policy should be to reduce risks, and their attendant costs, to the lowest economically feasible level. Utility investors are compensated for bearing some level of risk, and they should accept risks at that magnitude when they eventuate. The level of return normally experienced by a utility investor does not compensate for an extended reduction in the earning power of the investment, however, or for its complete loss. Thus, a clear shift in regulatory policy having the effect of allocating more risks to ratepayers will inevitably lead to an increase in capital costs over the levels historically experienced by utilities. Moreover, this cost increase will occur whether or not the commission expressly recognizes the shift in risk allocation it has adopted.

Nor is the level of return allowed or actually earned by the utility under historical regulatory policy the only germane factor when considering whether substantial additional risks should be assigned to investors. It must also be remembered that regulatory policy will invariably be applied to limit the utility investor's opportunity for profit. Instead, the whole thrust of regulation -- to base rates on the cost of service actually incurred by a utility -- serves to block the opportunity usually present in unregulated, competitive markets to seek the high profits available to a more efficient rival. These limits on profit opportunities are germane when considering the degree of risk for which a utility investor is being compensated.

The other reason for explicit recognition of risk allocation is that ratemaking is the achievement of a more equitable result. Because the goal is, of course, the lowest long-run cost to ratepayers, recognition of the risk allocation aspect of the decision leads to consideration of the benefits of risk spreading.

The risk premium associated with the existence of any investment risk can be reduced by spreading that risk over many people, thus reducing the risk experienced by any one person. Numerous mechanisms exist for spreading the risk; insurance and government are two examples. Unfortunately, complete insurance is not available for many risks, and it is often hard to justify why taxpayers should subsidize the costs of utilities.

When the benefits of risk spreading in reducing costs are considered, however, it becomes apparent that the larger the risk, the greater the proportion that should be borne by ratepayers. Risks involving relatively low costs can be readily absorbed by investors with little difficulty, so commissions might as well take full advantage of the risk-minimizing benefits of placing these risks primarily on investors. For high cost risks, however, the risk premium demanded by investors soars when they are asked to bear a greater share of the burden. At the same time, the incentives to minimize risk are substantial even if the investors bear only a fraction of the risk. All other things being equal, then, ratepayers will benefit the most in the long run, and they absorb a greater proportion of the risks themselves. In those unfortunate instances in which a risk becomes a reality, the ratepayer will face an additional cost burden, usually for a relatively limited period. Absorbing those costs is less expensive in the long run, however, than permanently having to pay a few extra percentage points on the company's equity capital, or perhaps even on its entire capitalization.

This kind of analysis seems far more productive than attempting to determine whether recovery of capital costs on a damaged plant should be permitted depending on whether
the plant is still used or useful, or asking whether recovery of investment in an incompletely funded facility should be allowed depending on whether the original decision to construct it was prudent. In either of those cases, the commission involved may conclude that its answer has raised the investment risk, leading ultimately to higher costs for ratepayers.

Returning to the areas of risk discussed above, some observations can be offered on the kind of result indicated by an awareness of the risk allocation aspects of the decisions involved.

First, in considering whether to disallow some portion of the investment in a successfully completed plant, the commission should carefully craft the standard of prudence which is the most important that a regulator may correctly decide the issue of prudence/imprudence as a subjective narrow, isolated factual questions unconnected to another or to larger issues of law and public policy. Rather, questions of prudence in such a case should properly be viewed in the context of relevant legal principles, and the prudence considerations. How the commission decides these issues can have consequences for the utility involved, its ratepayers and investors, as well as for other electric utilities, long after any particular case is concluded.

A regulator's task is not merely to decide whether it was prudent for a utility to have done X or failed to have done Y in constructing a particular facility. Instead, regulators must always be acutely aware that in determining whether a particular action or judgment is prudent they are making a policy judgment with respect to the apportionment of economic risk between ratepayers and investors. Individually and in the aggregate, those policy decisions hold important long- and short-term consequences. Prudence and imprudence therefore cannot be determined in a purely ad hoc fashion. A regulator must weigh all the consequences of drawing the line in one place or the other and must have a methodology or set of guidelines that is consistently applied in evaluating the literally thousands of managerial actions and decisions at issue.

The guidelines chosen by the commission should be consistent with established principles of law and policy. To make ex post facto changes in the rules by which public utilities operate would have grave consequences for utilities and ultimately for ratepayers. Commissions should therefore aim continuity in regulatory principles. I had occasion recently to consider the application of these general principles and policy considerations to the development of the concept of "prudence" itself. I concluded that to achieve these objectives, a judgment about the prudence of a managerial risk is a policy which public utility must be based on a standard of reasonableness. The finder of fact should not demand an optimal result.

In addition, the finder of fact should not apply hindsight but should determine whether the manager acted reasonably under the circumstances at the time of the decision and under the facts as then known. Above all, the finder of fact must avoid the fallacy of looking to outcomes as a method of judging the reasonableness of decisions that had to be made by their very nature, before knowledge of outcomes was available.

Next, the finder of fact should compare a manager's actions with those that other managers in similar circumstances would have taken. Actions that other competent managers would have taken cannot be considered imprudent.

Finally, even if managerial decisions were imprudent, costs should not be excluded from the rate base unless a prudent decision would have reduced the total costs of the project and then only to that extent.

Turning to abandoned plants, recognition of risk allocation factors suggests that ratepayers should bear the major share of the costs of abandoned plants. Given the utility's obligation to serve and the assumption of providing little or no returns to shareholders, there is little room for utilities to control this source of risk. Furthermore, the cost of abandoned plants often represents a major portion of the shareholder's investment; a history of nonrecovery for abandoned plants would, therefore, probably result in hefty increases in the required risk premium. It was this theory that was recently adopted as law by the Indiana legislature in the face of shareholder reluctance to invest in future plants following adverse decisions on nonrecovery of their investment in abandoned plants. Some risk should still be borne by investors, however, to encourage management to minimize both the likelihood and the cost of abandonment.

Although, in theory, the correct balance could be achieved by the present practice of amortizing investors' original investment and denying rate base treatment of the unamortized balance, this method has little analytical justification. In this connection, it is interesting to note that the PECF has recently undertaken to reexamine its long-standing policy of refusing a return on the unamortized investment in abandoned plants. A sounder approach might be to permit amortization of a fixed percentage (90 percent or more) of the cost and include in the unamortized portion in rate base. This method has the virtue of not allowing the relative allocation of risk between investors and ratepayers to be dependent on current capital costs or the period of amortization. The proper allocation of the risks of excess capacity is based on a similar analysis. Here, the issue should not be whether the existing capacity is used or useful, but whether the level of compensation paid to investors in the past justifies imposing upon them the consequences of depreciable non enhancing capacity now considered excess. In addition, it should be considered whether establishment of a policy that denies...
a return on capacity deemed to be excess will increase investor risk. A level that requires a higher overall capital cost in the future. These inquiries would create some degree of caution, both in determining whether capacity is actually excess and in denying substantial recovery of fixed investment costs. The way would be open in some circumstances, however, to reduce the required return on investment in capacity that clearly is not needed for reliable and adequate utility service. This approach resembles that adopted by the Iowa commission in the case discussed earlier.

Finally, the analysis also suggests that investors should not bear the full brunt of the risks associated with major accidents, because the magnitude of the losses tends to be substantial, while the ability to control the risk is limited.

This paper has attempted to clarify thought about the real nature of the decision being made when a risk allocation question is presented in a ratemaking situation. This leads, in turn, to recognition of the consequences of a given regulatory policy. With the vastly increased cost of new plants today, and with the increasing uncertainty in the market and regulatory environments that utilities face as they make or contemplate making those investments, it is critical that regulators, lawyers, and utility executives forge the soundest possible policy, both for ratepayer interests and investor interests, as they deal with the risks thus created. I hope that my suggestion that the risk allocation aspects of regulatory decisions be a clear center of focus will aid in achieving that result.

Notes


3. See, for example, Pennsylvania Power Co., 26 FERC ¶ 61,354 (1984). Recently, the FERC announced that a "reasonable utility management test" would be used to determine the prudence of specific costs: Would a reasonable utility management acting in good faith under the same circumstances have incurred the costs in question? New England Power Co., 31 FERC ¶ 61,047 (1985).


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THE DEVELOPMENT OF A SET OF PRINCIPLES FOR PRUDENSCE TESTS AND THEIR APPLICATION

Alan P. Buchmann

There is nothing new in the use of "prudence" as a test in utility ratemaking. What is new is the comparatively abrupt emergence of the prudence concept as a major factor in denying utilities recovery of and/or on substantial investments in utility facilities. This has gone hand-in-hand with more refined articulations of just what is "prudence" or its opposite, "imprudence," often called "mismanagement" (although the concepts may be quite different).¹

It serves little purpose to scan the cases and dictionaries for definitions. It might be noted, however, that authority can be found for the proposition that "prudence" is synonymous with "caution" [284 NW 475]. But what help are definitions drawn from a nonutility context? Is "caution" the standard to be imposed on an enterprise which has a service obligation? Plainly not. And the service obligation is or should be the overwhelming distinction between utility and nonutility legal analysis.

The primary cause of this increased interest in prudence tests lies, of course, in the dramatic changes in the electric industry over the last decade. The decreased growth in demand coupled with the extraordinary lead times required for the construction of generating facilities have led to enormous investments in plant which has been abandoned, or which has cost far more than originally estimated, or which now seems unnecessary, or any combination of these and other factors...
which make the expenditure seem questionable or at least questioned. As stated in a recent NRRI report, "the opportun-
ity for making an imprudent decision has been much greater recently than before," and "opportunities for imprudent deci-
dions are greater than in the past." While it seems odd to speak of "opportunities in this context, the authors are saying that things have become more complex and that a great deal of money is involved.

The issue is not, however, confined to the need for the construction of electric plants under past practices. The appropri-
ateness of utility decisions has been the subject of challenges for years, including: the need for electric gener-
ating facilities; the efficiency of construction practices; the need for better management of transmission lines; the propriety of fuel purchasing practices; the propriety of the supply practices of natural gas transmission and distribu-
tion companies; the operation and maintenance practices of electric utilities; and the selection of particular options under the Internal Revenue Act.

These can be multiplied, but the basic principle is a constant one: Utility ratepayers should not be charged for imprudent management decisions. It is unlikely that anyone could be found who would be willing to dispute this proposition and even more unlikely that any case law in support could be found. But, as so often, the proposition is grossly simplistic. It invites a number of questions, the more im-
portant being: What is imprudence? Who does pay for it?

Let us, for example, turn the proposition around. If we all agree that the ratepayer should not pay for imprudence, does it not follow that the ratepayer should pay for prudence? It wouldn't seem so, but that does not necessarily follow. In fact, it does not follow.

In his frequently cited dissent in State of Missouri ex rel. Southwestern Bell Telephone Co. v. Pub. Serv. Comm., 270 U.S. 276, 289 (1926), Mr. Justice Brandeis said: "The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding that might be dishonest or obviously wasteful or imprudent expenditures."

Leaving aside the difficulty of defining prudence as that which is not imprudent, this admirable principle came a cropper under the concept of "used and useful." The earlier cases deal with "prudent investment" as a rate base concept, but the idea of a constitutional rate base standard vanished with the Hope case. Every step, every expenditure, can be established as prudent, and recovery can be denied because the investment is not used in a rate base sense. This is what happened in Ohio with respect to the nuclear units cancelled by CAPCO. Conversely, even when a facility clearly provides service, it is still subject to the prudence test which may reduce its allowable cost. When an expense is involved imprudence may result in its disallowance, but prudence does not assure recovery. It may founder on the rock of the "test year concept."

Thus, the "prudence test," because passing that test does not mean you have passed the "prudence test" if the project falls, however prudent that test is, and because there is not a single test, is an impossible regulatory standard. This arises from the ultimate weapon in the regulatory arsenal, the burden of proof. Immediately after the remarks quoted above, Justice Brandeis said (262 U.S. at 289): "Every investor in a public utility may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown" (emphasis supplied). That is, there is a presumption of prudence. Almost every decision of which I am aware gives due obeisance to this principle. But the presumption is, in practice, of little or no value. The rule is not, as Justice Brandeis puts it, "unless the contrary is shown," which implies that someone has shown, that is, proven, something. As summarized in the NRRI report already mentioned, a presumption of imprudence was associated with the planning or construction of a power plant is challenged, the full original cost... is presumed to be prudent and includable in rate base. All one has to do is create a "serious doubt," and the bare fact of a cost overrun raises such a "serious doubt." Or, prudence is presumed, but the burden is on the utility "once that planning and management has been attacked" [NRRI]. A presumption which disappears upon attack is cold comfort indeed.

Assuming that a bare "attack" or "challenge" is not enough to overcome this illusory presumption, what is needed? As indicated, a bare showing of a cost overrun may be enough. If, speaking of generating facilities, there is a real question of prudence, no presumption at all [Penn. statute]. Conversely, is conformance with industry average costs -- difficult as they may be to calculate -- sufficient to sustain the presumption or to fend off the attack? It should be, unless it is assumed the entire industry is mismanaged, which is totally inconsistent with the presumption itself.

It follows, therefore, that a utility must always be in a position to prove that it has not been imprudent. That this is sometimes virtually impossible is beside the point. Once the question, then, is how does one show prudence? What is prudence? It is probably fairly well agreed -- although there are important exceptions to be discussed later -- that prudence
relates to a decision-making process. The earlier decisions seemed to indicate that the test was whether a decision had been made in a rational manner. This would entail proof of the decision-making process and, in a sense, proof that the decision process should be sufficient, even if the decision was "wrong" in some absolute sense. One would think so, even if they make mistakes, and there is considerable authority to support this conclusion. But LILCO was condemned in the ALJ's decision because its A/E had not discovered the errors of a vendor, an example of tertiary liability. In speaking of Zimmer, a consultant opined that it could not "agree that...blind reliance on independent engineering expertise was reasonable." But, assuming reasonable selection of the expertise, why should management rely upon it? If it horsepower expertise to its own and outguess its expertise, was it not imprudent to spend money on hiring them?

The basic unfairness of these prudence tests is, of course, that they are a one-way street. No case says that all prudent investment -- cheaper than reasonably expected -- should be increased for rate base purposes. If management does a superior job, wherein lies its rewards? Who brings us to the purpose of the whole exercise.

The objective of a prudence test, as stated earlier, is that the ratepayer not be charged for imprudent decisions. Leave aside the fact that the investor gets no direct increment for prudent ones -- other than the avoidance of a penalty. Assume an imprudent decision. How do we avoid charging the ratepayer for it?

We cannot in the long run. The disallowance of a nuclear unit, or part of it, from rate base will hold rates down. The current ratepayer will benefit. The current investor will lose, but the new investor will not lose, because the future ratepayer will pay a higher cost of capital. The circle is both complete and inexorable.

The fact is that most regulatory agencies are neither equipped nor competent to judge the prudence of decisions made by the regulated industry. This is not to say that all utility managements are ipso facto prudent. What it does mean is that, except in the most egregious circumstances, the regulators should either stay out or come in all the way. They must either participate in the decisions and be bound by, and bind their successors to, those decisions or stay out. A utility cannot perform its general task of providing service now, tomorrow, and ten years ahead under present circumstances, unless the regulators are prepared to recognize the huge risks involved.

And are they? It is highly doubtful. Listen to one of the conclusions of the cited NRRI report with respect to the prudent investment concept: "It is a handy regulatory tool because of the breadth of discretion and flexiblity it affords regulators." A "handy tool." That is, what was
once thought of as a, perhaps, constitutional standard for overall regulation has become an instrument -- with a "breath of discretion and flexibility" -- for regulatory interference, post facto, with utility management without regulatory responsibility. The potential consequences to utility service are enormous and adverse. Reliable utility service is far more likely to suffer from imprudent regulation than imprudent utility investment.

Note

1. It would seem a utility could "prudently" embark on and pursue a project, such as a generating plant, but do so inefficiently. The inquiry into the former aspect of the project should focus on the forecasting of demand and-supply and alternative supply options; in the latter, on construction management practices. The distinction does not seem to be articulated in the cases, although the former figures more in cancellation situations and the latter in completions.

RATE TREATMENT FOR NEW POWER PLANTS: COMMENTS ON THE FOUNDATIONS OF THE PRUDENT INVESTMENT TEST

Rosemary Pooler and Richard Goldsmith

The traumas experienced during the past fifteen years by the electric utility industry are familiar history. First, as economies of scale in power production disappeared, interest rates soared, health and safety regulatory requirements increased, and construction cycles lengthened, many companies found it extraordinarily difficult to finance their plans for capacity expansion.2 Persuaded that such expansion was required to assure the continuation of reliable service, rate regulators often provided rate relief in the form of CWIP -- an allowance which shifted responsibility for carrying the costs of new construction from investors to ratepayers.2 Then, as an explosive rise in oil prices triggered dramatic changes in the patterns of energy use throughout the nation, the sales forecasts on which the industry's expansion plans had rested failed to materialize, and much of the new capacity (with the aid of CWIP) then in the construction pipeline had to be cancelled.3 The sums lost were staggering. By 1982 more than 100 baseload units had been cancelled, with losses exceeding $10 billion, and $6 billion in further cancellations was anticipated.4 Again the industry required

Note: The authors thank Kim Frank, Class of 1987, College of Law, Syracuse University, for her research assistance.
rate relief, and again many respondents responded, this time by allowing the funds which had been sunk into abandoned projects to be amortized as a cost of service.5

Many baseload plants survived cancellation only to become a source of new trauma.6 Completed at many times their original estimated costs, these, if now entering service with price tags of $2-$4 billion.7 To make matters worse, they are often being added to systems already suffering from surplus generating capacity.8 Any economic benefits from the new will thus be limited to those which derive from its displacement of older, more expensive generation.9 Since these benefits accrue only slowly over time, conventional rate regulation -- which front loads recovery of capital costs9 -- will leave current consumers worse off with the new plant.10 When it goes into operation, they will experience higher -- perhaps sharply higher10 -- utility rates, a phenomenon aptly named rate shock.

A number of utilities have acknowledged this problem by accepting -- even proposing -- rate regulation in which they will permit the capital costs of a new generating station to be "phased" into rates over the first few years of the plant's operation.11 At the same time, the companies have insisted these plans be structured so as to assure them full recovery of their "prudent investment" in the new unit.12 Anything less would deprive them of a return to which they claim they are entitled, both as a matter of law and regulatory tradition. This paper explores these two contentions; the first part examines the legal status of the so-called precedent rule, and the second part considers its policy ramifications. We conclude that the rule is compelled neither by law nor sound regulatory policy, but we reach the second conclusion more tentatively. Regulation does not permit a utility to pay how much for a multibillion dollar generating station, which has perhaps cost far more than it will ever be worth, face an extraordinarily difficult problem whose solution may have far-reaching consequences for both the structure of the electric utility industry and the practice of regulation.

### Prudent Investment

One of the more unusual features of the current controversy concerning the proper rate treatment of new but excess generating capacity has been the assertion that a public utility is legally entitled to a fair return (or, at least, to the opportunity to earn a fair return) on all its prudently invested capital.15 Some have even suggested that this rule is an essential term of some "social bargain" between consumers and investors which regulators are supposed to protect.16 This is rather surprising for at least two reasons. First, while it has always been understood that rate regulation is an area bounded by law, its precise parameters have never been clearly delineated.17 In more recent times, moreover, the courts have virtually withdrawn from their once active supervision of ratemaking, leaving regulators with even more room for the exercise of discretion than they once enjoyed. The contention that the prudent investment rule thus seems a bit dubious.

Efforts to establish the legal pedigree of the rule usually trace its lineage to Southwestern Bell,18 where, in his famous concurrence, Justice Brandeis said of the amount prudently invested" as the measure of rate base.20 This opinion, it must be remembered, was written in the context of a lively debate then being waged over whether "original" or "replacement" cost should be used to establish the "value" of utility's rate base.21 Brandeis, of course, urged the adoption of original cost for valuation purposes, but he acknowledged that original cost should be taken only as the amount "prudently invested."22 In this context, then, his test for "prudent investment" has offered as a rule for inventorying capital costs for rate base but for valuing rate base already inventoried by operation of some other standard -- most probably the "used and useful" rule.23 Those who today cite the Brandeis opinion to support the utility industry's claim of entitlement to a return on all capital prudently invested are thus wenching that opinion out of context. In the process, they have transformed language intended to express a rule of rate base exclusion -- prohibiting a return on capital imprudently invested -- into a rule of rate base inclusion.24

Second, any claim of entitlement to a return on capital invested in the utility enterprise simply because the investment cannot be said to have been improvident is hard to square with the "used and useful" rule, which permits only a return on capital invested in rate base only of those assets used and useful in providing service.25 This rule, dating back to Sway v. Ames,26 has achieved nearly universal recognition as one of the basic principles of the public utility regulation.27 For most of this time it has operated quietly to preserve intergenerational ratepayer equity by linking responsibility for the capital costs of service with its benefits,28 and the rule would thus seem to be as essential a term of the social bargain between consumers and investors as any other.

During the past fifteen years, the used and useful rule has been riddled with exceptions as regulators, under increasing pressure from the "new economics" of the electric utility industry, have been forced both to permit the inclusion of CWIP in rate base29 and to allow recovery of (and, in some cases, a return on) investment in abandoned plant.30 These major departures from the rule, together with occasional applications which seemed to deprive the rule of any real meaning,31 have no doubt encouraged some to conclude that "used and useful" has become a mere slogan.32 We believe, however,
that the rule continues to express an important goal of rate- making: state equity between generations. 

That the goal endures as well is illustrated by the recent decision of the Federal Energy Regulatory Commission allowing electric utilities to include in their wholesale rate base 30 percent of their investment in plant under construction. 33 Since such plant is not yet in service, the tension between this CWIP allowance and the used and useful principle is obvious. Nevertheless, because many utilities were experiencing difficulty financing their construction programs, the commission might readily have defended its decision as a justifiable departure from the used and useful rule. Interestingly, it chose not to do so. Instead, when the CWIP allowance was challenged, the commission argued that its decision was "based on the "life's share" of the benefits, the tension between the used and useful rule "understood as a principle of intergenerational equity." 34 This was so because, in the commission's judgment, capital invested in plant under construction "confer[es] a present benefit on customers, namely, the reasonable assurance of a continuing quality of service....[and therefore]...it was reasonable for current ratepayers to pay for this benefit." 35 This rationale may not be wholly convincing -- indeed, even the commission conceded that its CWIP rule did not achieve intertemporal ratepayer equity as well as did the AFUDC method of accounting that it replaced. 36 But the effort made by the commission to reconcile its decision with the used and useful rule at least demonstrates that the policy concern for rate equity -- remains one of continuing vitality.

The commission's struggle to harmonize its rule with that policy also serves as a reminder that "fairness" is not the only criterion of sound rates. Important to the advancement of the prudential investment rule is the criterion of "adequacy," which implies that a utility's return on its investment should be sufficient to enable it to attract the capital it needs in order to continue to provide adequate service at reasonable rates. 38 The distinction between these two criteria is, of course, not surprising. Ever since the Hope decision, 39 the regulatory process has been understood as an essentially legislative one in which regulation should have enormous social and public interest as they balance the conflicting interests of consumers and investors. 40 There are limits to this discretion, to be sure, but they are not necessarily exceeded by a rate order which fails to provide a utility with an opportunity to earn a "fair" (that is, market) return on its investment or, for that matter, by a rate order which fails to allow any return at all. 41 In such a world, it would be unrealistic to expect that either a "used and useful" rule (which always favors investors) or a "prudent" investment rule (which always favors consumers) would enjoy perpetual privacy. 42

This is particularly so in situations in which the enormous sum at stake assure that a decision one way or the other will have a significant effect. It is thus not surprising that when regulators have confronted the problem of excess capacity they have developed new ratemaking techniques which apportion the costs of that capacity to both consumers and investors. 43 Sometimes this balancing process is acknowledged explicitly, 44 but more often it is simply implicit in the outcome. 45

Regardless of the particular technique chosen for its effectuation, cost sharing has been characterized as a breach of the basic social bargain which regulation has implied between consumers and investors. 46 First, because utilities have accepted a limited return on their investment, it is suggested that the "life's share" of the benefits, particularly "good" investments has gone to consumers; from this it is concluded that the losses occasioned by particularly "bad" (but not imprudent) investments should also be allocated to consumers. 47 Second, it is urged that because utilities have accepted the obligation to serve all customers on reasonable terms they are required to forecast future needs and must make the investments which appear necessary for those needs to be met; from this it is concluded that any disallowance of a return on such an investment (again, absent imprudence) results in an improper "penalty." 48

The problem with the first argument is that it misstates the facts. For decades utilities actually earn returns in excess of their allowed, bare-bones cost of capital 49 while rates declined during the 1950s and 1960s, costs declined more rapidly. 50 Regulatory lag was part of the social bargain between consumers and investors and operated to provide the latter with a substantial portion of the benefits of the former's investments. Requiring them now to share the costs of "bad" ones thus does not seem at all inconsistent with that bargain.

The problem with the second argument is that it misstates the fact. Requiring investors to share the costs of excess capacity is not a matter of imposing a penalty but of allocating not its costs. 51 Under competition, the risk of uneconomic capacity expansion is borne by investors in the enterprise, not its consumers. These investors are compensated for this risk. On the other hand, with returns higher than those commonly allowed to utilities, while it thus seems inappropriate, based on the model of a competitive market, to allocate the risk of excess capacity entirely to investors, it seems equally inappropriate to allocate this risk entirely to consumers -- especially since utility shareholders control the company's exposure to an earnings shortfall and receive a return on their investment that compensates them for this risk as well. 52

The moral irony of cost-based regulation is that even if the risks incident to managerial mistakes (here, the costs of excess capacity) are allocated to investors in the short
run, this will only lead to an increase in the company's cost of capital, which in turn reallocates these risks to consumers in the long run. The real issue under cost-based regulation is thus not whether the costs of excess capacity should be allocated to ratepayers or to investors but which method of allocation among ratepayers is the better one. This, of course, is an issue of policy, not law, which we believe should be resolved on the basis of the considerations discussed in the next section.

**Policy Ramifications**

Historically, the entry into service of a new baseload generating unit created problems of intergenerational equity. New capacity additions were closely followed by new load, and declining production costs meant that the arrival of a new unit would be accompanied by lower average prices. Under these conditions, conventional rate treatment of the new unit would incorporate a decline in the rate base in a reasonably fair allocation of its costs over time. Today, the same approach commonly fails to achieve intergenerational equity. Where the new unit's capacity is not immediately needed for the reliable service of load, the economic benefits which may be derived from its operation in place of older, more expensive units will accrue only slowly over time. Under these conditions, conventional rate treatment -- which front loads a company's return on its capital investments against current ratepayers too much and future ratepayers too little. In addition, because this quick recovery of capital costs reduces management's incentive to assure that the plant remains in service for its entire economic life, conventional rate treatment also places a premium on the risk of early failure -- and, at least for nuclear units, this risk seems not insubstantial.

This intertemporal misallocation of costs and risks can be remedied in some cases by the use of "phase-ins" or accounting techniques such as annuity depreciation or trended base rate which can defer recovery of the new unit's cost to a time when its operation provides consumers with net benefits. In many other cases, however, the capital costs of the new unit are large enough to offset the operational savings anticipated over its lifetime, and such cases of truly uneconomic excess capacity present fairness problems not remediable by ratemaking techniques that simply defer the recovery of capital costs. In cases such as Susquehanna 1 and 2, Wolf Creek, Nine Mile 2, and Shoreham are several which come to mind -- where net economic benefits to ratepayers from generation of new advanced technology power plant cannot reasonably be projected, any ratemaking technique that requires ratepayers to pay for that plant (for example, on the theory that its construction was not imprudent) will not satisfy the fairness criterion.

A few state utility commissions have begun to respond to this new problem by allocating a portion of the costs of uneconomic capacity to investors through "excess capacity adjustments." The method for calculating this has varied from case to case as the regulators have struggled to reconcile their conflicting obligations to investors and consumers. "All or nothing" decisions, however, have generally been rejected in favor of an adjustment which balances the interests of investors and consumers by requiring the costs of uneconomic capacity to be shared between them. Frequently, the rationale for the precise balance struck has not been forthcoming; 

It would be a mistake, nevertheless, to conclude that these decisions rest on a mere legalism; at their roots are considerations of "fairness" which are an enduring concern of ratemaking.

Elementary economic theory teaches that welfare cannot be maximized when decision makers do not face all the economic costs of their decisions. Rates which provide investors with the same return regardless of the economic value of their investment can thus only operate to promote managerial indifference to optimal capacity expansion. To be sure, allocating any portion of the costs of excess capacity to investors may very well lead to an increase in the industry's cost of capital. This will depend upon the extent to which capital markets have already discounted the risk of excess capacity adjustments and also upon the extent to which utility management, now aware of the risk, adds to or reduces the capital-intensive strategy for future service. In any event, if the industry's cost of capital does rise, this will simply enable the true costs of new capacity to be measured in the marketplace, rather than be hidden by a capital subsidy extracted from consumers.

The threat that rates will rise as a result of relieving ratemakers of the burden of paying for excess capacity reveals the near futility of contemporary rate regulations. However, the costs of uneconomic capacity may be allocated to investors in the short run, the imperatives of the capital market assure that these costs must be recovered through rates in the long run. Regulators are thus damned if they do and damned if they don't. What this may suggest is that the old (cost-based) rate treatment of new generating stations may have outlived its usefulness. Cost-based regulation worked well enough during the decades of risk-free capacity expansion, when declining production costs and steadily increasing sales combined to assure that both the "cost" and "value" of new capacity moved together. Today, in an era of high risk capacity expansion, increasing production costs and unpredict-
able growth in demand have combined to assure that the "cost" and "value" of a new power plant will often diverge dramatically. In such a setting it obviously makes less sense than it once may have to rely on a regulatory regime that automatically allocates all of the costs of uneconomic capacity expansion to ratepayers. Competitive markets would allocate the costs of such "bad" investments to investors, suggesting that it may now be appropriate to reweigh more on competition rather than regulation for inefficient supply. Of course, competition would also allow investors to capture the rewards of "good" investments, but with the disappearance of natural monopoly in the supply of generation, consumers no longer need protection from monopoly pricing, and the deregulation of generation may thus be entirely appropriate. The successes of PURPA in eliciting cogeneration and small power production, as well as the recent emergence of least-cost energy supply planning as a criterion for measuring the prudence of new plants still under construction, ibid., pp. 99-106. See also, "Survey on Regulation of the Wolf Creek Nuclear Power Plant," pp. 429-57. (The symposium discusses the regulatory problems of the recently completed wolf Creek plant).

Notes


2. As of April 1979, 33 state PUCs had allowed CWIP to be reflected in rates. See General Accounting Office,
Institute, 1984, pp. 3-16. Historically, a reserve margin of 20 percent has been used as a planning criterion by most PUCs and utilities. Ibid., p. 8.

9. These benefits flow primarily from lower fuel and operating costs. Various commissions have acknowledged these displacement benefits when deciding how to treat a plant with excess capacity. See, for example, Washington Utilities and Transp. Comm’n v. Pacific Power and Light Co., 60 PUR 4th 188 (Wash. PUC 1984); Re Iowa-Illinois Gas and Electric Co., 46 PUR 4th 616 (Iowa PUC 1982); Re Duke Power Co., 60 PUR 4th 333 (N.C. PUC 1984).

10. See, for example, Re Southern Cal. Edison Co., cited in note 7 (discussing problem of conventional capital cost recovery and considering a variety of alternative accounting techniques).

11. See, for example, Penna. PUC v. Penna. Power and Light Co., 55 PUR 4th 185, 200 (Pa. PUC 1983). ("The bottom line is that the ratepayer would be better off without [Susquehanna I] from an economic standpoint now and for the foreseeable future.") Re New York State Electric & Gas Corp., Case 28824, Op. No. 85-8 (N.Y. PSC Stip. Op. Issued April 8, 1985). (Even with a phase-in, rate year revenue requirement associated with Somerset plant was $546.47, while rate year benefits were only $39 million. See ibid., Commissioners Mead and Pooler concurring.)

12. See, for example, Matter of Kansas City Power & Light Co., cited in note 7, p. 76. (Conventional rate treatment of the Wolf Creek generating station would have occasioned first-year rate increases of 52 percent for Kansas City Power & Light Co. and 98 percent for Kansas Gas & Electric Co.; Re Union Electric Co., cited in note 7 (Conventional rate treatment of the Callaway unit would have required a first-year rate increase of 65 percent.)

13. See, for example, Matter of Kansas City Power & Light Co., cited in note 7, p. 76. (Kansas City Power & Light proposed a four-year phase-in to avoid a first-year rate increase of 52 percent; Kansas Gas & Electric proposed a five-year phase-in to avoid a first-year rate increase of 98 percent.); Re Union Electric Co., cited in note 7. (The utility proposed a five-year phase-in.); Matter of Niagara Mohawk Power Corp., Case No. 29069 (N.Y., Rec. Dec. of ALJs Issued Dec. 13, 1985). (The utility proposed a three-year phase-in for Nine Mile Point 2.)


16. See Kahn, "Who Should Pay for Power-Plant Duds?" Wall Street Journal, August 15, 1985; Re Nine Mile Point 2 Nuclear Generating Facility, Case No. 29124 (N.Y. PSC, Rehearsal testimony of Anthony J. Barabino et al., p. 9, January 6, 1986). (The prudent investment rule was said to be part of a "silent, but nonetheless critical, compact between the Commission, consumers . . . and . . . investors.")

17. Rate regulation is, of course, subject to both statutory and constitutional limits. For almost fifty years, the latter were laid down by Smith v. Ames, 165 U.S. 466 (1897), which held that a regulated company was entitled to rates that covered operating expenses and provided a "fair return" on the "fair value of the property being used by it for the convenience of the public." Ibid., pp. 466-67. More recently, the Smith test was replaced by the "end result" test of FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944), under which a rate order will be upheld if, after "a balancing of the investor and consumer interests" (ibid., p. 603), "the total effect of the rate order cannot be said to be unjust and unreasonable." Ibid., p. 602. Obviously, neither one of these tests involves the drawing of a bright line, and the constitutional limits on rate regulation is thus a subject that continues to provoke debate. See, generally, Drobak, "From Turnpike to Nuclear Power: The Constitutional Limits on Utility Rate Regulation," Boston University Law Review 65, no. 65 (1985).

18. statutory limits on rates were for many years no more precise or rigorous than those provided by the Constitution. Legislation, of course, differs in detail from state to state, but most state regulators have concluded under similarly worded statutes authorizing them to establish rates that are "just and reasonable" (see, for example, N.Y. Public Service Law § 65 [1]), and these broadly worded statutes have often been liberalized to continue as grants of authority coextensive with that permitted by the Constitution. See, for example, People ex rel Kings County Lighting Co. v. Millican, 210 N.Y. 479 (1914) (importing the "used and useful")
doctrine of Smyth v. Ames into construction of New York law; Pennin Basin Area Rate Cases, 390 U.S. 747, 770 (1968) ("the just and reasonable standard of the Natural Gas Act 'coincides' with the applicable constitutional standards"); Penn. PUC v. Penna. Gas and Water Co., 423 A.2d 1213, 1219 (Pa. 1980) (the requirement of "just and reasonable" rates set forth in the statute "confers upon the regulatory body the power to make and apply policy concerning the appropriate balance between prices charged to utility customers and rates imposed on capital to utility investors consonant with constitutional protections applicable to both"). But see Citizens Action Coalition of Indiana, Inc. v. Northern Indiana Public Service Co., 485 N.E.2d 510 (Ind. 1985) (strictly construing a statute that authorized "just and reasonable" rates for utility "service" to prohibit rate recovery of costs of cancelled plants).

Recently, a number of states have enacted laws prescribing more specific limits on rate regulation. These laws are intended to protect consumers from being required to pay for utility investments from which they derive no benefit. See, for example, 66 Pa. C.S.A. § 1315 (Pa. 1988 Supp.) (prohibiting inclusion of construction costs in rate base before a facility is "used and useful"); 20 V.A.M.S. § 393.135 (Mo. 1996 Supp.) (same); RSA 378:30-a (N.H. 1984) (prohibiting any recovery in rates of costs associated with construction of a facility "not completed"). Compare Kan. Stat. Ann. § 66-128 (1984 Supp.), the so-called Kansas rate shock statute, which, while it eliminates in great detail the considerations pertinent to the ratemaking treatment of a new generating unit, may leave the Kansas State Corporation Commission with as much discretion as it had previously. Contrast Glickman, "Allocating the Cost of Constructing Excess Capacity: Who Will Have To Pay For It All?" University of Kansas Law Review 33, no. 429, p. 431 (rate shock bill "not a drastic departure from accepted ratemaking practice") with Houston, Albrecht, and Redwood, "An Economic Perspective of Rate Suppression Legislation," University of Kansas Law Review 33, p. 469 (rate shock bill "greatly alters the power and institutional role" of the Kansas PUC).

18. This expansion of regulatory discretion was the inevitable result of FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944), which held that ratemakers were not bound by any single ratemaking methodology, and that their rate order would not be upset unless the end result was patently unjust. See, for example, KPM Welch, "Status of Regulatory Commissions Under the Hope Natural Gas Decision," Georgia Law Journal 32 (1944): 136. (Hope ended judicial control of rate regulation.)


23. See ibid. Despite the heated debate over valuation methodology, the prevailing rule for inclusion in rate base at the time of Southwestern Bell was the used and useful rule of Smyth v. Ames, 169 U.S. 466, 546 (1898); see Tennessee Gas Pipeline v. FERC, 606 F.2d 1094, 1109 (D.C. Cir. 1979).

24. Brandeis makes clear that the proffered prudent investment test is one for exclusion when he states: "The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or improvident expenditure." Southwestern Bell Telephone, 262 U.S., p. 289, n. 1 (emphasis supplied).

25. See, for example, Tennessee Gas Pipeline v. FERC, 606 F.2d 1044, 1109 (D.C. Cir. 1979).

26. 169 U.S. 466 (1898).

27. See, for example, Tennessee Gas Pipeline v. FERC, cited in note 25; Kentucky Utilities Co. v. FERC, 760 F.2d 1209, 1224 n. 4 (D.C. Cir. 1985). ("For nearly a century the 'used and useful' principle ... has stood as a bedrock principle of utility rate regulation.")

28. See, for example, Tennessee Gas Pipeline, 606 F.2d at 1109-10; Kentucky Utilities Co. v. FERC, cited in note 27. ("The principle is simple -- it requires that costs associated with electric power plants be paid by the ratepayer who benefits from the plant.") See, generally, FERC, Construction Work in Progress for Public Utilities; Inclusion of Costs In Rate Base, 48 Fed. Reg. 24323, 24 335-37 (1983).
29. See note 2.

30. See notes 3-5.

31. See, for example, Abrams v. PSC, 104 A.D.2d 135, 137-38 (3d Dep't, 1984). ("The test of whether expenditures may be deemed 'used and useful' is not whether the expenditures have resulted in a facility providing electric service to the public, but whether the expenditures were prudently undertaken toward that end.")

32. See Kahn, "Who Should Pay for Power-Plant Duds?" cited in note 16.


35. See ibid., citing 48 Fed. Reg. at 24331.

36. See ibid. While the Court of Appeals upheld the FERC's decision, the court seemed more constrained by prior precedent than persuaded by FERC's rationale. See Mid-Tex Electric Co-op v. FERC, 773 F.2d at 345-47 (1985).

37. James Bonbright's three criteria for sound ratemaking -- fairness, efficiency, and adequacy -- are undoubtably well known and appreciated. The fairness criterion implies that customers should pay for the costs of service in proportion to their derived benefits, and this is as true for the allocation of costs across time as for the allocation of costs among customer classes. See Bonbright, Principles of Public Utility Regulation (1961), p. 292. Matter of Niagara Mohawk Power Corp., Case No. 29069 (N.Y. PSC, Direct testimony of Miles O. Bidwell, August 1985).

38. See ibid.


41. Hope clearly envisioned circumstances under which the public interest might outweigh investor interests; see 320 U.S., p. 603. ("Regulation does not insure that the business shall produce net revenues.") See also Iowa-Ill. Gas & Elec. v. Iowa State Comm'n, 347 N.W. 2d 423 (Ia. 1984) (upholding rate order reducing rate of return on excess capacity with the observation that "the fixing of rates requires 'a balancing of the investor and the consumer interests,' even if the balance should result in no net revenues for the utility" [citing Hope, p. 428]); Penna. Elec. Co. v. Penna. PUC (Pa., Dec. 22, 1995). ("In cases where the balancing of consumer interests against the interests of investors poses rates to be set at a 'just and reasonable' level which is insufficient to ensure the continued financial integrity of the utility, it may simply be said that the utility has encountered one of the risks that imperil any business enterprise, namely the risk of financial failure.")


43. See, for example, Re Iowa-Illinois Gas and Electric Co., 59 PUR 4th 385 (Iowa PUC 1984). (Concluding that the Louisa generating station represented about 150 Mw of excess capacity, the commission allowed the total investment in rate base but adopted a rate-of-return adjustment as a mechanism for apportioning the costs of that capacity between ratepayers and consumers;)
Penn. PUC v. Penna. Power and Light Co., cited in note 11. (Concluding that Susquehanna 1 represented 100 percent excess capacity, the commission included the plant in rate base but disallowed a return on a portion of the utility's investment; see note 64 below.); Re Union Electric Co., cited in note 7 (excess capacity costs of Callaway shared between consumers and investors through an eight-year phase-in); Re Kansas City Power & Light Co., cited in note 7. (Concluding that the Greek represented both physical and economic excess capacity, the commission "divided the economic consequences between ratepayers and shareholders by permitting the investment in the plant to be recovered through disallowing any return on that investment to the extent that it exceeded the plant's 'value'.")

44. See, for example, Re Iowa-Illinois Gas and Electric Co., cited in note 43; Re Kansas City Power & Light Co., cited in note 7.

45. See, for example, Penna. Pub. Util. Comm'n v. Penna. Power & Light Co., cited in note 43; Re New Jersey Central Power & Light Co. v. Federal Energy Regulatory Comm'n., cited in note 46 below; Re Union Electric Co., cited in note 7 (purporting to apply "prudent investment rule" to allow return on excess capacity but adopting eight-year "phase-in" because this would match burdens of new unit with its benefits).

46. See, for example, Kahn, "Who Should Pay for Power-Plant Duds?"; Re Niagara Mohawk Power Corp., cited in note 13, p. 55 (proposal to share costs of excess capacity 50-50 between ratepayers and shareholders, saying the sharing would "establish a standard heretofore unknown in regulation ... [which] ... would change the rules of regulation in midstream").

47. See, for example, Kahn, "Who Should Pay for Power-Plant Duds?"

48. Ibid. See, for example, the company's argument in Natural Gas Pipeline Co., cited in note 42, 765 F.2d at 1163.


50. See Joskow, "Inflation," p. 305; Kahn, "Who Should Pay for Power-Plant Duds?"


52. It is patent nonsense, moreover, to contend that consumers have borne the risk of excess capacity all along and hence that cost-sharing "would change the rules of regulation in mid-stream." Re Niagara Mohawk Power Corp., cited in note 46; see also "Utility to Ask Court to Overturn PUC's Ruling on Costs for Nuclear Unit," Energy Users Report 13 (BNA), May 2, 1985, p. 400. ("It's sure as hell changing the rules at the middle of the game."") Under the "rules of the game" established since Hope, ratemaking has been viewed as a process of balancing the competing interests of consumers and investors, with an outcome that "need not insure net revenues." See Jersey Central Power & Light Co. v. Federal Energy Regulatory Comm'n., cited in note 42; see also Penna. Elec. Co. v. Penna. PUC (Pa. Dec. 9, 1985) (upholding removal of Three Mile Island Unit 1 from rate base with the observation that Hope does not require the setting of rates at a level that will, in any given case, guarantee the continued financial integrity of the utility concerned"). Whether this process, with its attendant risk of an earnings shortfall whenever consumer interests are found to outweigh investor interests, was in fact understood by a utility is, of course, legally immaterial. See Buckelschuss v. Monsanto, 104 S.Ct. 2862 (1984) (investment-backed expectations must arise from an accurate view of the law before they can be protected by the due process clause).


55. Ibid. According to staff's calculation, conventional rate treatment of the two units involved in this case would have required ratepayers to pay $460 million per
year net of fuel savings in 1984, but ratepayers in 2014, the end of the plant's useful life, would have received a net benefit of some $1.1 billion in nominal dollars.

56. See ibid., pp. 486-87.

57. Phase-ins are quickly becoming commonplace. See, for example, Re Iowa-Illinois Gas & Electric Co., 56 PUR 4th 249 (I1. PSC 1981) (commission did not base rate on excess capacity recoverable in over five years. The commission adopted the phase-in approach because it mitigated rate shock and more closely approximated marginal cost pricing.); Re Union Electric Co., cited in note 7. (the Missouri commission adopted an eight-year phase-in of Callaway in order to ensure that benefits to ratepayers accompanied the burdens.) Compare Re Utah Power and Light Co., 66 PUR 4th 32, 34 (Wyo. PSC 1985). (the commission excluded from rate base two-thirds of the utility's investment in Hunter No. 3 because it represented excess capacity. At the same time, the company was permitted to accrue a carrying charge on the excluded investment collectible if and when the plant becomes used and useful.) Under trended rate base (TRB) ratemaking, the value of rate base is increased over time to reflect increases in the replacement value of the asset. TRB has been considered as a method of ensuring intergenerational equity but to date has not been adopted by any commission. See Re Southern Cal. Edison Co., cited in note 7, p. 469. Another proposed method of dealing with intergenerational inequities is the annuity or sinking fund depreciation approach which utilizes a depreciation schedule that increases over time, resulting in an investment recovery (depreciation and return) that is constant in nominal terms. See Re Southern Cal. Edison Co., cited in note 7, p. 468; Re Niagara Mohawk Power Corp., cited in note 13, pp. 39-44.


62. See notes 27 and 28. See also Penna. Electric Co. v. Penna. PUC, cited in note 41. (*In fairness, consumers should not be required to buoy up failing utility companies by being required to, in effect, provide public subsidies for utility properties that are not useful in the public service.*)

63. See note 43. See also Re Otter Tail Power Co., 44 PUR 4th 249 (N.D. PSC 1981) (commission disallowed equity return on investment in excess capacity); Re Niagara Mohawk Power Corp., 10 op. NYPSC 911, 924-26 (Nov. 16, 1976) (commission allowed inclusion of excess capacity in rate base but lifted some of the burden from ratepayers by imputing to the company more sales than the company had projected).

64. See ibid.

65. See, for example, Re Niagara Mohawk Power Corp., cited in note 53. When the company brought its Oswego No. 5 oil-fired unit into service, the plant represented under economic excess capacity. The NYPSC sought to strike an "equitable" balance in apportioning the costs of the plant by imputing to the company one percent more sales ($6,750,000 in revenues) than the company had projected. Since the total revenue requirement associated with the plant was about $21,500,000, this required current ratepayers to supply only $14,750,000 and shifted to the company's shareholders the risk that the imputed sales would not materialize. The commission concluded that this unequal sharing of the costs of excess capacity was "equitable" but provided no clue to its reasoning. See also Penna. PUC v. Penna. Power and Light Co., 55 PUR 4th 185 (Pa. PUC 1983). Having concluded that the company's share (945 Mw) of Susquehanna I represented excess capacity, the commission did not use the actual cost of the unit (about $1700/kw) to determine the dollar amount of the disallowance. Instead, the average cost of all the utility's capacity (considerably less than $1700/kw) was used to determine the dollar cost of the 945 Mw of excess capacity. This had the effect of shifting some of the costs of the new unit to ratepayers. Just why the precise balance struck was regarded as "fair" was not addressed.


67. See, for example, Kahn, "Who Should Pay for Power-Plant Duds?"

68. See, for example, Re Niagara Mohawk Power Corp., Case 29069 (N.Y. PSC, Direct Testimony of Miles O. Bidwell,
Aug. 1985). (The actual cost of Nine Mile Pt. 2 will most likely exceed $5 billion. The present value to ratepayers, however, is less than $2.5 billion.) Re Long Island Lighting Co., Case No. 28252 (N.Y. PSC, Direct Testimony of Richard A. Rosen, Oct. 11, 1985). (Even with a $1.35 billion IVA, improvement adjustment, Shoreham is estimated to cost ratepayers about $4.7 billion more than if the plant had never been built, that is, Shoreham has no present value but represents a deadweight loss of $4.7 billion.) Re Kansas City Power & Light Co., cited in note 7, p. 60. (The commission determined that the actual cost of the Wolf Creek plant was over $2600/kw but that the plant's value -- based on the costs of a coal-fired plant meeting the company's needs -- was only $1250/kw.)


70. See, for example, Kahn, The Economics of Regulation: Principles and Institutions (1971), p. 161: ("The critical . . . characteristic of natural monopoly is an inherent tendency to decreasing unit costs.") Since central station generation is no longer characterized by declining costs, the natural monopoly rationale for regulation no longer applies; see, for example, Loose and Flaim, "Economics of Scale and Reliability: The Economics of Small Versus Large Generating Units," Energy Systems and Policy Journal 4 (1980): 37.

71. Section 210 of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C.A. § 824a-3 (1985), was designed to encourage the development of alternatives to central station generation by removing the then-existing institutional barriers to cogeneration and small power production -- essentially by requiring electric utilities to buy and sell power from qualifying facilities. See, generally, American Paper Inst. v. American Elec. Power Serv. Corp., 481 U.S. 402 (1985). Many states have since passed similar laws, for example, N.Y. Public Service Law § 66-c.


73. Because the construction of a new generating unit involves scores of complex decisions which, in theory, must be judged only in the light of the circumstances existing at the time those decisions were made, prudence review requires an intensely detailed examination of management decision making that is both costly and difficult to administer. See Re Union Electric Co., cited in note 7, pp. 211-59 (prudence review of the Callaway nuclear plant encompassing everything from project management control process to the number of "portable restroom facilities" utilized); Long Island Lighting Co., Case 27563, Opinion No. 05-25 (N.Y. PSC, 1st Op. Issued Dec. 16, 1985) (determination of prudent costs of the Shoreham Nuclear Generating Facility); see, generally, Burns et al., "Prudent Investment," pp. 62-74. These burdens have been enough to deter even the undertaking of a prudence investigation; see Pierce, "Regulatory Treatment of Mistakes in Retrospect," pp. 511-12. Even where a prudence review is conducted, it may not be conducted well. In the context of an investment which has turned out to be a multibillion-dollar mistake, the temptation to succumb to hindsight may be hard to resist. See, for example, Burns et al., "Prudent Investment," pp. 69-76 (discussion of Zimmer investigation and use of "final outcome" test). Even where properly conducted, the outcome of a prudence review will always be unpredictable. This uncertainty presents yet another "regulatory risk" and thus may add to a utility's capital costs without any assurance of compensating savings to ratepayers.
The main issue addressed by Ronald Melicher and Douglas Heath, George Avery, Alan Buchmann, and Rosemary Pooler and Richard Goldsmith is risk allocation. The authors look to who bears the "risk" of already incurred costs under traditional ratemaking as opposed to who they believe should bear the risk. They are not satisfied that traditional ratemaking is equitable either for ratepayers or shareholders.

The basic tenets of public utility ratemaking allow utilities to recover all prudently incurred costs of doing business, including the costs of bringing major operating facilities on line. However, because of the rate effects the new facilities cause, these basic tenets now face challenges from many quarters. For example, one criticism is that the cost recovery mechanism under traditional practices results in "intergenerational" inequities. Others argue that traditional ratemaking forces ratepayers to experience "rate shock" when expensive and newly completed plants are brought into ratetbase. Still another group contends that traditional methods shield utility stockholders from the risks associated with construction projects, thereby forcing ratetpayers into the role of risk-bearers. Finally, there are those who berate the after-the-fact reviews that are essential in determining which of the project's costs were "prudently" incurred.

Clearly, traditional ratemaking methods are being challenged. These papers explore the aspects of intergenerational equity, risk, and prudence reviews, with the authors concluding that prudence reviews are, at best, a tenuous method by which to assure equitable cost recovery.

**Intergenerational Equity**

In the paper by Pooler and Goldsmith the issue is raised of "rate equity" among present and future generations of ratepayers. They believe the traditional method of "front-loading" costs of construction projects causes current ratepayers to bear costs more appropriately assigned to future ratepayers.

In order to remedy this intergenerational inequity the authors advocate Trended Rate Basing (TRB), which they state "can defer recovery of the new unit's capital costs until a time when its operation provides consumers with net benefits." They also endorse value-based pricing, in which the value of the plant's capacity and energy to the system would be assessed at the time the plant comes on line. Both methods defer cost recovery of facilities to some future date.

Although the conceptual arguments underlying these phase-in proposals are appealing, the rate effects resulting from TRB and value-based pricing would be less attractive. Under both concepts, present ratepayers are better off at the expense of future ratepayers. Whether this represents an improvement or degradation in equity depends, one suspects, on whether one is a present or future ratepayer.

**Risk Sharing**

Interestingly, all the authors conclude that any attempt to shift risk from ratepayers to shareholders ultimately leads to ratepayers bearing the additional costs of that risk. As Pooler and Goldsmith state, "however the costs of uneconomic capacity may be allocated to investors in the short run, the imperatives of the capital market assure that these costs must be recovered through rates in the long run."

Similarly, Avery contends that "it is a fact that the ratepayers ultimately will bear all costs associated with supplying regulated services. Commissions often speak in terms of allocating certain costs between investors and ratepayers. Any risk-related costs allocated to investors, however, are going to find their way back to the ratepayers in some form or other, because the market compels commissions to provide investors with returns commensurate with the returns they could receive elsewhere."

Buchmann claims that in the long run we cannot avoid charging the ratepayer for an imprudent decision. He points out that "the disallowance of a nuclear unit, or part of it, from the rate base will hold rates down. The current
ratepayer will benefit. The current investor will lose. The new investor will not lose, however, and the future ratepayer will pay a higher cost of capital."

Finally, Melicher explores the question of risk allocation through empirical evidence. His analysts demonstrate that investors are wary of utilities with nuclear plants under construction. Melicher also finds that once a plant is completed and in rate base, the investor’s measure of return looks even better than for those utilities without any nuclear plants. Both findings easily comport with our expectations. They indicate that those who invest in plants under construction are subject to substantial risks, but once the plant is completed and in rate base, ratepayers assume the operational risks.

The Prudence Concept

Avery defines prudence cases as "those ratemaking proceedings in which a utility faces the possibility that an imprudence disallowance will be applied to a portion of its investment in a new facility." From an investor’s viewpoint, the major problem with prudence reviews is that the regulators focus on the past, where other circumstances and other rules may have applied. They look for an already incurred cost, an expense from the past that they believe should not have occurred, and prevent the utility from recovering that cost. This disallowance is, of course, a serious risk for the investors.

Although the authors agree with Buchmann’s statement that ratepayers will ultimately be charged for "imprudent" management decisions and feel that prudence tests are ill-conceived and inadequate, only Poller and Goldsmith offer some thoughts on how to prevent the inequities arising from the use of prudence tests. They contend that the "used and useful" rule, which "permits the inclusion in rate base only of those assets used and useful in providing service," is vastly superior to a prudence standard in equitably valuing ratepayers' cost of responsibility. This rule, they believe, "has operated quietly to preserve intergenerational ratepayer equity by linking responsibility for the capital costs of service with its benefits.

Poller and Goldsmith hope, however, that competition will render prudence tests obsolete. This notion ties in with their endorsement of value-based pricing. They state that in today’s competitive marketplace, "the ‘cost’ and ‘value’ of a new power plant will often diverge dramatically," and they believe the adoption of a value-based pricing scheme would motivate utility companies to lower costs.

Conclusion

The authors are not at all confident that the issue of equitable risk allocation can be adequately resolved. They seem to agree with Poller and Goldsmith that, for the time being, traditional ratemaking with "prudence reviews will remain a crude but essential part of cost-based regulation.

As stated earlier, the main shortcoming of prudence reviews is that they focus on the past. Both ratepayers and shareholders would be better served if regulators stated their objectives before beginning new plant construction. In other words, regardless of whether commissions apply traditional risk allocation methods, such as the "used and useful" rule, or adopt new methods, such as TRB or value-based pricing, shareholders must know what risks are involved before investing their money. Regulators should be discouraged from changing the rules "in the middle of the game," so to speak.

In sum, considerations of equity dictate that we agree on ground rules for risk allocation at the outset and forge ahead from that point. Looking backward serves only to slow the progress which we need to make in order to achieve our goal of equity.
Part Six
Excess Capacity and Structural Issues in Electricity
THE COST EFFECTIVENESS OF COGENERATION AND CONSERVATION UNDER EXCESS CAPACITY

Mary Andrews Bane

Many electric utilities today, facing uncertain demand and rising costs of traditional generating sources, find themselves in a supply planning dilemma. Increasing utility attention is being directed at efforts to influence how and when energy is used by utility customers. Conservation and cogeneration (or customer generation) both affect customer demands on the utility system and have a corollary, usually indirect, effect on the supply of energy available. Active encouragement by the utility of conservation and customer generation at first glance appears incongruous with the existence of excess utility generating capacity. This paper examines some of the issues of note when evaluating the cost effectiveness to the utility of aggressive pursuit of conservation and customer generation in periods of excess utility generating capacity.

The particular motive driving adoption of a conservation measure depends on one's viewpoint. For example, a homeowner may purchase a high efficiency air conditioner in order to reduce the cost of electricity for cooling. The local utility may encourage the use of high efficiency appliances in order to reduce weather-related peak demand, thereby eliminating the need for early additions to generating capacity. The state regulatory commission may encourage conservation to minimize societal costs of power production and increase efficient use of available energy resources. These diverse motives have the potential of working against one another.
Of interest for purposes of this discussion are conservation programs in which the utility is directly involved in initiating action.

Conservation programs represent but one alternative available to a utility for reducing the magnitude or timing of customer demand. The available classes of action are generally described by the term "demand-side management" (DSM), which can include utility promotion of customer generation, especially in the form of qualifying facility (QF) and/or energy efficiency. Like rate demand-side management programs, customer generation reduces system load during some or all hours. It can also provide electricity for resale to other customers.

Traditionally, a distinction has been made between demand-side and supply-side activities. However, all activities which reduce demand also affect supply because they free existing capacity for use by other, nonparticipating, customers. The redirected capacity is just as real as that present in a new power plant. The decision to invest in capacity through demand-side management load reduction programs is part of the set of planning decisions related to providing capacity adequate to meet anticipated demand.

A utility must begin the process of preparing to meet future demand well before that demand exhausts the utility's existing generating resources. Consider that a baseline coal-fueled power plant has an idealized construction period of eight years. A utility must decide to build such a plant at least eight years before it is needed if the plant's capacity is to be available soon enough. A utility seeking to substitute conservation-induced capacity or customer-generated capacity for that needed capacity must begin acquiring that capacity before it would be necessary to start construction of the plant.

In deciding which method is best to provide the needed capacity -- construction, strategic conservation, or customer generation -- the utility must evaluate each using a common approach. Avoided cost techniques were developed and augmented for this purpose.

Current Methods of Valuing Conservation and Cogeneration

Both conservation and customer generation affect customer use of electricity. Conservation measures directly reduce energy usage and possibly demand on the utility system. Customer generation for self-service also reduces demand on the utility system. Both conservation and customer generation indirectly increase the supply of energy available for other customers, and customer-generated sales may result in a net increase in the supply of electricity available to the utility system.

Current evaluation techniques seek to value the benefits cost pricing. The concept is simple: Alternative capacity is worth as much as the utility investment it avoids. If conservation can provide as much capacity as a new power plant, then the value of conservation is the same as the costs associated with the power plant.

The price to be paid by the utility for capacity and energy provided by an alternative generating source is similarly determined. When a utility contracts with a qualifying facility (QF) for both firm capacity and energy, the utility avoids virtually all of the generation costs -- both fixed and variable -- which it would have incurred had it generated the electricity itself. Yet, as-available energy sales generally can only lead to the avoidance of the variable cost component of an equivalent amount of utility power production. Because of the uncertainties associated with as-available energy deliveries, the utility must still provide the capacity to produce the energy and thus incurs the fixed cost of the new power plant.

The avoided cost is calculated through the use of the avoided unit's capital financing requirements schedule. This schedule is a table of yearly costs over the useful life of the facility that shows the amount of revenue required to pay for the avoided unit. The avoided cost is not simply the cost of construction. It includes financing charges, taxes, return on investment, and depreciation. The total yearly cost decreases over time as the plant is depreciated.

Table 1 illustrates the annual revenue requirements for one kw of capacity of an intermediate plant whose in-service date is January 1991. The construction period is assumed to be five years, and all construction work is in progress as of January 1991. The cumulative present worth of one kw of capacity over the life of the plant is $891.

This is the cost to the utility that could be avoided if an alternative, less expensive means of generation were utilized to supply the needed power.

Estimation of Cost Effectiveness

Cost-benefit analyses may be performed from the perspective of a specific customer, a specific utility and its ratetakers, or for all utilities and all ratetakers (society). In determining whether a particular conservation program is "cost-effective" for the utility, the cumulative present value of the benefits to the utility of the proposed program is compared to the cumulative present value of the costs to the utility of the program through some specified horizon year. If the benefits exceed the costs, then the program is said to be cost-effective to the utility. A variety of factors can affect the estimation of cost effectiveness.

The Role of Time

Cost-benefit analyses are performed from the perspective of a specific customer, a specific utility and its ratetakers, or for all utilities and all ratetakers (society). In determining whether a particular conservation program is "cost-effective" for the utility, the cumulative present value of the benefits to the utility of the proposed program is compared to the cumulative present value of the costs to the utility of the program through some specified horizon year. If the benefits exceed the costs, then the program is said to be cost-effective to the utility. A variety of factors can affect the estimation of cost effectiveness.
analyses estimate avoided costs (benefits) beginning with the in-service date of the "avoided" plant, until that in-service date, sufficient or "excess" capacity would exist, and there would be no "avoided costs" (benefits) to offset utility expenditures for either conservation or cogenerative power. The costs associated with conservation would likely occur prior to the in-service date, while the benefits (avoided costs) would occur after that date. Depending on the period selected, the estimation of the avoided costs will differ, and the evaluation of the cost effectiveness of alternatives to the planned power plant will vary accordingly.

Referring again to Table 1, one may illustrate the effect of the time horizon selected on the estimate of the avoided cost. For a time horizon of ten years, from 1986 through 1995, the avoided cost (cumulative present value of revenue requirements) for one kw of capacity is $657.69, compared to an avoided cost of $891 per kw over the life of the plant.

Inclusion of CWIP in Rate Base

Since the utility must begin construction of a plant five years prior to the needed in-service date, it begins expending funds in 1986 for the plant with an in-service date of 1991. An accurate estimate of the benefits to the utility of not constructing a plant is provided if the revenue requirements evaluation estimate includes all construction work in progress (CWIP) in rate base during the period of construction. Revenue requirements analysis with CWIP excluded from rate base during the period of construction (1986-1990) would distort the timing of benefit flows to the utility of the avoided construction.

Inclusion of CWIP in rate base affects the evaluation of cost effectiveness in two ways. First, the benefits associated with conservation programs undertaken during periods when the utility has more than enough capacity appear more favorable when CWIP is included for the years of construction prior to the in-service date. The utility avoids cost of construction during the years when there is excess capacity if aggressive pursuit of conservation programs will supply adequate alternative capacity to avoid construction of a traditional generating facility. Second, many problems with early capacity payments to QFs can be eliminated by the adoption of CWIP cost accounting. When a QF comes on line prior to the in-service date of the avoided unit, the purchasing utility may pay for firm capacity at a price determined by the present value of unit deferral. In order to protect the utility from QF nonperformance after the in-service date, the QF is generally required to provide a bond to indemnify the utility from loss. This bond may be very costly, with the result that some projects will not materialize. An alternative to early payments would be to price early capacity
by the avoided utility construction cost for each year, as found through the application of CWIP. The use of this payment scheme would more accurately reflect the avoided costs to the utility than would the estimate of the present value of the deferral over the in-service life of the avoided plant.

The Role of Risk

Traditional cost effectiveness evaluation methods examine the avoided monetary costs and benefits associated with particular DSM activities. They typically, however, do not address relative risks. This omission may ultimately distort the value of a study's given alternative, since the alternative which appears to be the more cost effective may in fact be more risky and hence more costly in the long run.

The effects of risk first surface with the utility's load forecasts. The current condition of excess capacity is the direct result of incorrect forecasts of demand. While the selected source of new capacity cannot reduce forecasting errors, it can reduce the cost of being wrong.

Capacity acquired through strategic conservation and customer generation programs normally have two risk-reducing features. First, they cost the utility less than building new base load generating plants and can be added in smaller increments. Second, most state public service commissions readily approve cost recovery for such programs. Yet, one can readily find examples of state commissions delaying power plant cost recovery until after the plant is actually in service and occasionally disallowing cost recovery if the costs are determined to be imprudent.

There are, of course, risks induced by DSM activities. The greatest risk relates to the fact that the utility is attempting to modify someone else's behavior in order to increase available capacity. The uncertainty of customer action has both long-term and short-term aspects. The long-term uncertainty derives from whether a sufficient number of participants can be acquired to produce the needed "nameplate" capacity. The short-term uncertainty comes from the participants' ability to control the capacity. Thus the main sources of risk associated with DSM programs are the uncertainty of the capacity's existence and (the lack of control over) the timing of its use.

When comparing DSM activities, capacity provided by customer generation is provided in larger increments by fewer participants. Therefore, the uncertainty of its availability at a particular time may be greater than that produced by the other DSM activities. However, the factors often exist to mitigate the effect on the utility of this greater risk. For most utilities, customer generation represents a very small percentage of total generating resources. For example, in Florida, which is the third ranking state for total customer generation capacity, qualifying facilities represent a scant 2 percent of total generation. The utility with the highest proportion of QF capacity is expected to have 10 percent of its customer load served through such capacity by 1990. If all customer generation in the state went off line for a year, demand would vary no more than it did between 1982 and 1983. If one also considers that the availability of customer generating units is very high -- typically more than 90 percent -- and the fact that most self-generating customers adopt interruptible standby service, the risk associated with customer generation becomes no greater than other DSM programs adopted by most utilities.

Utility pursuit of conservation and cogeneration can offset some of the risk of supplying new generating capacity to meet uncertain demand growth. The increasing number of utilities proposing several small gas-fired units rather than a few large coal facilities may be evidence of utility recognition that the addition of smaller increments of capacity will serve to reduce risk while maximizing revenues. DSM programs may provide needed capacity additions for less cost than even small power plants without producing offsetting risk. At the very least, DSM activities may provide the utility with greater flexibility in planning for future levels of electricity demand.

Some Guidelines for Consideration

Start-up times for conservation programs and customer generation facilities are considerably shorter than the construction time for a traditional generating unit. By the in-service date of an avoided plant, however, conservation programs must have reduced anticipated demand by the amount of capacity needed, or customer generation facilities must be in place which can supply dependable alternative capacity. Failure to institute conservation programs during periods of excess QF capacity will eliminate conservation costs over a viable means for avoiding construction of an additional generating unit. Likewise, failure to establish an environment conducive to the development of customer generation facilities during periods of excess capacity may preclude the existence of such capacities when the additional generating capacity is needed. In determining whether actively to pursue strategic conservation or aggressively seek contracts for customer-generated power when excess capacity exists, several factors should be considered by the utility.
Duration of Excess Capacity

"Excess capacity" is usually a short-run phenomenon due to the lumpy nature of electric capacity additions. The period of excess capacity is dependent on the rate of growth in the load placed on the utility system. If a utility is experiencing little or no growth in load, then any excess capacity may continue for an extended time. While this may be the case for some specific utilities or regions, this is not the general expectation.

The chairman of the North American Electric Reliability Council, John P. Williamson, believes that "generating capacity margins in this country are expected to decline over the next two years. Ten years is a reasonable planning horizon for utilities given the frailties of forecasting techniques. If the excess capacity is expected to last for ten years or less, then it may be appropriate for a utility actively to pursue strategic conservation and customer generation.

Feasibility of Off-System Sales

Excess capacity may present a problem only when a utility is viewed in isolation. Extensive utility interties would make such isolation improbable and the possibility of sale of excess power very likely. Some regions have well-developed interties for wheeling power from one utility to another. If these exist, the determining factor would be the utility's marginal fuel cost.

Relative Costs

The relative costs of conservation programs, customer generation, and construction of traditional generating facilities should be critically reviewed and compared to the associated benefits of each. Decisions regarding which type of program to pursue should be based on the relative net benefits of each program.

Relative Investment Risks

Efforts should be made to identify the risks associated with the various means for meeting needed generating capacity. Most utilities are permitted to flow directly through to customers expenses associated with conservation and purchases of energy and capacity from customer generators. Although the utility is not permitted to earn a return on investments in conservation or customer generation, the risk associated with having too much capacity is eliminated. Frequently, utilities are being denied inclusion in rate base of plant not deemed used and useful. This can pose a substantial risk to a utility planning construction of major generating facilities, given the uncertainties associated with accurately
PRICING UNDER EXCESS CAPACITY

Excess generating capacity is one of the most troublesome issues facing the electric utility industry. New coal-fired and nuclear power plants are being completed in regions that currently have enough base load capacity to meet expected demand over the next five or ten years (or even longer). The costs of these new power plants often mean that utilities are asking for substantial rate increases at a time when high electricity prices appear to be holding down demand growth. State regulators and the utilities have proposed various solutions to this problem of rate shock, including phasing the new capacity into the rate base, redefining depreciation rules, denying a return to stockholders on capacity judged to be excess, or even excluding excess capacity from the rate base altogether.1 We can add to this issue the current controversies over the prudence of many new power plants and the management by the utilities of large construction projects.

The purpose of this paper is to take a step back from the policy issues and look at what excess capacity means for the optimal pricing of electricity. The objective is to establish basic concepts which could then be used to evaluate the economic implications of various proposals for pricing excess capacity. In particular, I will show that optimal pricing (that is, marginal cost pricing) under excess capacity will not provide sufficient revenues to meet total costs and that there exists a second-best pricing structure that dominates (in a welfare sense) the most obvious alternative to marginal cost pricing, uniform average cost pricing, or any other form of uniform pricing, and is considerably more practical to implement than Ramsey prices or subsidies to utilities.

The rationale for optimal pricing is that prices are the mechanism through which decentralized decision makers achieve an optimal allocation of resources. Prices give consumers and producers information about the costs of providing various goods and services and serve to direct resources into their most productive uses. Because of this, optimal prices also determine the optimal amount of resources to be used in producing goods and services, and the optimal amount of output of goods and services. In one sense, optimal prices and excess capacity are contradictory. In the short run, however, optimal prices provide the market signals that there is too much or too little capacity. In a competitive market, these signals are profits or losses. In a regulated industry, however, profits and losses are excluded by the regulatory process. As a result, utilities with excess capacity are generally able to pass on the costs of excess capacity to consumers (and are generally prevented from earning profits if capacity is less than the optimum; see Reinfelds [1984]).

Most of the various policies for "pricing excess capacity" are in fact, methods for reducing the cost of such capacity to the consumer and, in a sense, emulating a competitive market's method for signaling that there is excess capacity by forcing producers to accept losses.2 These policies do not pass the capacity the utilities actually have and use to generate electricity. Regardless of the method used to specify the cost of capacity (short of complete exclusion from the rate base and from operating costs), utilities are entitled to recover the allowed costs. Similarly, as long as excess capacity is not ordered mothballed or dismantled, this capacity will be used, and the problem of pricing electricity under excess capacity remains.

I will assume that all generating capacity is priced at its actual cost and that the utility is able to recover its full costs. These assumptions are not necessary, but the various proposals to exclude some or all of the costs of excess capacity have long-run implications that warrant separate and serious consideration beyond the scope of this paper.

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Note: The opinions expressed here are entirely the author's and do not necessarily reflect the positions of the Department of Energy or the Energy Information Administration.
Optimal Pricing: A Review of the Literature

In the context of this paper, the economic literature on public utility pricing follows two main trends -- marginal cost pricing and monopoly pricing. As will be seen, the problems of excess capacity bring these trends together.

The focus of research into marginal cost pricing has been to find the best ways to define marginal costs for public utilities. It is given that this is the optimal pricing method, and the research problem has been to find ways of implementing this type of pricing. In the simplest case, there are two demand periods, peak and off-peak, and a single rate of profit associated with the adverse implications of electric utilities. (This means a single type of generator) (Boiteaux 1960, Steiner 1957, Williamson 1966). Marginal cost pricing in this case sets the off-peak price equal to marginal operating cost (which is assumed to be constant), and peak price equal to marginal operating cost plus marginal capacity cost (also assumed to be constant).

Several issues limited the implementation of this form of marginal cost pricing. First, the stochastic nature of electricity demand, random generator outages, and the existence of diverse types of generators are all ignored. Second, peak demand customers were perceived to face an unreasonably high price if they alone pay capacity costs. Third, there was the possibility that marginal cost would be less than average cost, and total revenues would fall short of total costs.

Extension of the utility pricing model to include stochastic demand and supply uncertainty (due to random generator outages) considerably modified marginal cost pricing. Under uncertainty, consumers in all periods contributed to the demand for capacity; therefore, marginal costs have a capacity component for all periods. Base load costs (which are denoted by $b_0$ and $b_1$) are added to the load costs noted by $b_1$ and $b_2$. (Stern and Visscher 1978). It was also shown that peak period customers contributed most to the demand for capacity and should pay a higher price. 3

Similarly, when the diversity of generator technologies was incorporated into the analysis and explicit recursion was made that peak loads are in fact met by peaking generators, marginal cost pricing was again modified so that capacity costs were shown to be a component of marginal costs in all periods (Campon 1976). The cost characteristic of this capacity is $c_1 = b_1$, $c_2 = b_2$, and $c_3 = b_3$.

The possibility that marginal cost pricing would not produce enough revenue to cover total costs led to consideration of alternative pricing. The optimal solution to this problem was to use marginal cost pricing and subsidize the utility. This solution raised a new issue of trying to identify who should pay the subsidy and the adverse effects of raising taxes to finance government subsidies. Ramsey prices (Ramsey 1927) defined the conditions of second-best pricing for a utility selling in different markets (including different demand periods) when marginal cost pricing did not meet revenue requirements, by specifying the optimal transfer from one group of utility customers to another through different prices for the same product sold in the different markets. Prices in each market are inversely proportional to the elasticity of demand in that market, which means that implementing Ramsey prices requires accurate measures of price elasticities.

An alternate approach to Ramsey prices was to examine discriminatory pricing, such as two-part tariffs and declining block rates (Of 1971). Although this type of pricing is usually associated with the adverse implications of monopoly, subsequent analyses showed that monopoly pricing with a regulated profit constraint was Pareto-superior to average cost pricing (Leland and Meyer 1978; Willig 1978). The principal objection to two-part tariffs or declining block rates was that small consumers would pay more than under average cost pricing. This objection can be overcome by allowing consumers to choose between average cost prices (or any other uniform price that differs from marginal cost) and a two-part tariff or block rate. The resulting nonlinear pricing system increases aggregate social welfare without decreasing the welfare of any one group of consumers (Willig 1978).

Optimal Pricing with Excess Capacity

Figure 1 shows a linearized approximation of a standard load duration curve. The total hours in the year are divided into periods that are defined by (1) base load only, (2) base load plus intermediate load, and (3) base load plus intermediate load plus peak load. The number of hours in each period is denoted by $z_1$, $z_2$, and $z_3$, respectively. Base load itself is $x_1$, intermediate load is $x_2$, and peak load is $x_3$. Note that the total load on the system at peak is the sum of the component loads, $x_1 + x_2 + x_3$. Loads are defined to include reserves and allowances for planned and unplanned outages.

There are three types of generating capacity -- base, intermediate, and peaking. The total capacity of each type is designated $C_1$, $C_2$, and $C_3$, respectively. Each type of capacity has its own cost characteristics (which are assumed to be homogeneous for each type). Costs are divided into annualized capacity costs, measured in cents per kw per year, and operating costs, measured in cents per kwh. Capacity costs for generator types $i$ are denoted by $b_i$, and operating costs are denoted by $b_i$.

The usual cost relationships are assumed, that is, $b_1 > b_2 > b_3$ and $b_1 < b_2 < b_3$. 4
A Simple Load Duration Curve

Figure 1.

Base capacity is the most expensive to build and the least expensive to operate, while peaking capacity is the least expensive to build and the most expensive to operate. Intermediate capacity is in the middle for both costs. It is also assumed that

\[ b_1 + b_1 < b_2 + b_2 < b_3 + b_3. \]

Optimal prices for each demand period are those prices that maximize the sum of producers' plus consumers' surplus for the year. In fact, the optimal prices are the marginal costs of generating electricity in each demand period, and the purpose of the formal analysis is to define the marginal costs in each period.

The Appendix describes the formal optimization problem and the derivation of the optimal prices. Table 1 shows optimal prices for two cases – with and without excess capacity. The essential result of the analysis is that when there is excess capacity, optimal (that is, marginal cost) prices will not yield enough revenue to cover total costs. As shown in the Appendix, marginal cost pricing without excess capacity does produce enough revenue. Since the marginal cost prices in the presence of excess capacity are strictly the marginal operating costs and do not include marginal capacity costs, the revenue shortfall occurs.

### Table 1. Marginal Costs by Demand Period

<table>
<thead>
<tr>
<th>Demand period</th>
<th>With excess capacity</th>
<th>Without excess capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>( b_1 )</td>
<td>( b_1 + \frac{b_2 - b_2}{h_1} )</td>
</tr>
<tr>
<td>Base</td>
<td>( b_1 )</td>
<td>( b_1 + \frac{b_2 - b_2}{h_1} )</td>
</tr>
<tr>
<td>Intermediate</td>
<td>( b_2 )</td>
<td>( b_2 + \frac{b_2 - b_2}{h_2} )</td>
</tr>
<tr>
<td>Peak</td>
<td>( b_3 )</td>
<td>( b_3 + \frac{b_3}{h_3} )</td>
</tr>
</tbody>
</table>

Given this shortfall, there are several options. First, utilities could charge optimal prices and be subsidized, perhaps by the government (using tax money or fees charged to utility customers). This option was often proposed in the early literature on marginal cost pricing when the assumption of homogeneous generating capacity led to optimal pricing rules that were likely to produce a revenue shortfall. Second, the utilities could charge average cost, using a uniform price across all demand periods. A variant of this option would be to charge the average cost in each demand period, allocating capacity costs among the demand periods. Third, utilities could use two-part tariffs, including declining block rates, to increase revenues enough to cover costs. This option has the disadvantage of making small consumers pay a price above the average cost. Fourth, utilities could adopt a nonlinear outlay schedule that allows consumers to choose between paying average cost or a two-part tariff. As noted in the literature survey, this option is Pareto superior to any pricing system other than marginal cost pricing (with or without subsidies). In addition, average costs can be separately specified for each demand period, retaining the useful principle that peak period customers pay a higher price than base period customers.

In a situation, such as excess capacity, in which marginal cost pricing is not feasible because of the revenue shortfall and objections to subsidizing utilities by user fees or government reimbursement, a nonlinear outlay schedule that allows the utilities to just meet total costs appears to be the second best option, especially when average costs are calcu-
lated for each demand period. Table 2 shows how average costs are allocated among the three demand periods. It is obvious that the average cost in the base period exceeds the excess capacity marginal cost. It is not obvious, however, that average costs in the intermediate and peak periods exceed the corresponding excess capacity marginal costs, and in fact there are no a priori grounds for demonstrating that average cost is greater than marginal cost in either period. Depending on the actual values of the b's, b's; b's, and \( x_{ij} \)'s, the excess capacity marginal cost can exceed average cost in the intermediate and peak periods, especially if the operating cost of peaking generators \( (b_3) \) is high relative to other costs.

If average cost in a demand period is less than excess capacity marginal cost, then the marginal cost is the correct price for that period. Surplus revenue (that is, revenues that exceed total cost in the period) can be used to offset average cost in the base period.

An examination of a nonlinear outlay schedule for the base period would be useful. Such a schedule for a single consumer can be defined as follows:

\[
\begin{align*}
P_{10} q_1 & \quad q_1 \leq E \\
E t + (P_{10} - t) q_1 & \quad q_1 > E
\end{align*}
\]

where \( q_1 \) is consumption; \( P_{10} \) is system average cost in the base period, calculated from a forecast of base period demand using average cost pricing; and \( r(q_1) \) is the consumer's outlay. The outlay schedule is illustrated in Figure 2. Note that \( E \) is the level of consumption that separates consumers who choose average cost from those that choose the two-part tariff. Assuming that the price elasticity of demand is negative, consumers choosing the two-part tariff will consume more electricity than they would have under a uniform price equal to base period average cost. Willig (1978) showed that when the largest consumer had an average outlay equal to marginal cost, the resulting price schedule was Pareto dominating. This means that all consumers are paying at least the operating cost of base generators, while the total capacity cost is spread out over a large volume of sales, reducing the average capacity cost. Then, if total revenue in the period exceeds total costs, the price charged to average cost customers can be adjusted downward. Consequently, small consumers under a nonlinear outlay schedule are no worse off than under uniform average cost pricing and may be better off, while large consumers are definitely better off, and utilities are able to cover their total costs. This discussion applies to the use of nonlinear outlay schedules in intermediate and peak demand periods.
At the same time, different price structures are possible for base, intermediate, and peak demand periods, thus preserving some of the allocated and informational benefits of time-of-use pricing. As mentioned earlier, it is possible for marginal cost in the peak demand period (or even in the intermediate period) to exceed average cost for that period even with excess capacity. If so, marginal cost is the appropriate price.

This last observation raises an interesting point. With excess capacity, the marginal cost in the base demand period is always less than average cost in that period. The real problem with excess capacity is paying for base load generators, not peaking units. For this reason, excess capacity is a matter of serious concern only when there is excess base load capacity, and attempting to measure excess capacity by looking at reserve margins may not be useful. Instead, capacity factors appear to be a better measure of excess capacity because low capacity factors for base load generators indicate that such generators are not being fully utilized. Of course, load duration curves in practice are not linear, and deciding what constitutes a "low" capacity factor for a specific utility may require extensive investigation. Nonetheless, capacity factors provide more information about potential excess capacity than reserve margins and should be the focus of research into measuring excess capacity.

Notes


2. There is an asymmetry here in that utilities are not able to capture the profits that a competitive enterprise could capture in the short run by providing a product at a lower price or by providing a new product. (In the long run, competition will eliminate these profits, just as competition eliminates excess capacity.) This problem of allocating risks and rewards in a regulated market is another aspect of the electric utility industry that is receiving considerable attention these days, but it is beyond the scope of this paper.

3. Another consequence of uncertainty was that capacity was not fully utilized at all times and that idle capacity was not necessarily excess capacity.

4. That is, maintenance outages and forced outages are treated as additions to customer load.
5. This option is the one most often found in current rate structures, especially when there is some form of seasonal time-of-use pricing.

6. See Stoffersahn (1984) for an example of the use of a complex system of rates to deal with excess capacity.

Appendix

Optimal Electricity Pricing

Optimal electricity prices are obtained by finding the set of prices that maximizes the sum of consumers’ plus producers’ surpluses across the three demand periods. Because of the possibility of excess capacity, load on any one type of generator need not equal capacity. Therefore, let $x_{ij}$ be the load on generator $i$ during period $j$, where $i = 1, 2, 3$, and $j = 1, 2, 3$. The sum of the areas under each of the demand curves is given by

$$A = h_1 \begin{bmatrix} x_{11} & x_{12} & x_{13} \\ x_{21} & x_{22} & x_{23} \\ x_{31} & x_{32} & x_{33} \end{bmatrix} \begin{bmatrix} P_1 & P_2 & P_3 \\ P_1 & P_2 & P_3 \\ P_1 & P_2 & P_3 \end{bmatrix} \begin{bmatrix} h_1 \\ h_2 \\ h_3 \end{bmatrix},$$

where the number of hours in each period convert load (in kw's) to generation (in kwh's).

Total capacity costs (TCC) are given by

$$TCC = b_1 c_1 + b_2 c_2 + b_3 c_3.$$  

Total operating costs (TOC) are given by:

$$TOC = h_1 b_1 x_{11} + h_2 (b_1 x_{12} + b_2 x_{22}) + h_3 (b_1 x_{13} + b_2 x_{23} + b_3 x_{33}).$$

Electricity load is constrained by capacity. There are two types of constraints for this problem. One applies to total system load and total system capacity in each demand period, and the other to load and capacity of each type of generator. The system constraints are

$$x_{11} \leq C_1,$$

$$x_{12} + x_{22} \leq C_1 + C_2,$$

$$x_{13} + x_{23} + x_{33} \leq C_1 + C_2 + C_3.$$  

The constraints on each capacity type are

$$x_{11} \leq C_1,$$

$$x_{12} \leq C_1,$$

$$x_{13} \leq C_1,$$

$$x_{22} \leq C_2.$$
\[ x_{23} \leq C_2, \]
\[ x_{33} \leq C_3. \]

Note, however, that there are redundant constraints. Obviously, the constraint \( x_{11} \leq C_1 \) appears in both sets. However, \( x_{12} + x_{22} \leq C_1 + C_2 \) and \( x_{12} \leq C_1 \) necessarily imply that \( x_{22} \leq C_2 \), and the constraint \( x_{22} \leq C_2 \) is also redundant. Pulling the pieces together, the result is the nonlinear programming problem:

Max \( W = h_1 \begin{array}{l} x_{11} + x_{12} + x_{22} + x_{13} + x_{23} + x_{33} \end{array} \)

subject to

\[ x_{11} \leq C_1, \]
\[ x_{12} + x_{22} \leq C_1 + C_2, \]
\[ x_{12} + x_{23} + x_{33} \leq C_1 + C_2 + C_3, \]
\[ x_{12} \leq C_1, \]
\[ x_{13} \leq C_1, \]
\[ x_{23} \leq C_2, \]

and \( x_{ij} \geq 0 \) for all \( i, j \).

The Lagrangian is

\[ L = h_1 \begin{array}{l} x_{11} + x_{12} + x_{22} + x_{13} + x_{23} + x_{33} \end{array} \]

\[ - B_1 C_1 - B_2 C_2 - B_3 C_3 - h_1 b_1 x_{11} - h_2 (b_1 x_{12} + b_2 x_{22}) \]
\[ - h_3 (b_1 x_{13} + b_2 x_{23} + b_3 x_{33}), \]

where \( \lambda_k \geq 0 \) \( k = 1, \ldots, 6 \) are the Lagrangian multipliers.

The Kuhn-Tucker conditions are

\[ x_{11} : \ h_1 p_1 = h_1 b_1 + \lambda_1, \]
\[ x_{12} : \ h_2 p_2 = h_2 b_1 + \lambda_2 + \lambda_4, \]
\[ x_{22} : \ h_2 p_2 = h_2 b_2 + \lambda_2, \]
\[ x_{13} : \ h_3 p_3 = h_3 b_1 + \lambda_3 + \lambda_5, \]
\[ x_{23} : \ h_3 p_3 = h_3 b_2 + \lambda_3 + \lambda_6, \]
\[ x_{33} : \ h_3 p_3 = h_3 b_3 + \lambda_3, \]
\[ \lambda_1 : \ x_{11} (C_1 - x_{11}) = 0, \]
\[ \lambda_2 : \ x_{12} (C_1 + C_2 - x_{12} - x_{22}) = 0, \]
\[ \lambda_3 : \ x_{13} (C_1 + C_2 + C_3 - x_{13} - x_{23} - x_{33}) = 0, \]
\[ \lambda_4 : \ x_{12} (C_1 - x_{12}) = 0, \]
\[ \lambda_5 : \ x_{13} (C_1 - x_{13}) = 0, \]
\[ \lambda_6 : \ x_{23} (C_2 - x_{23}) = 0, \]

and \( x_{ij} \geq 0 \) for all \( i, j \),

\[ \lambda_k \geq 0 \] for all \( k \).

Note that these conditions are obtained by recursively solving the equations that result from differentiating the Lagrangian by the \( x_{ij} \)'s to obtain a set of equations that contain only one price term.

The interpretation of the Kuhn-Tucker conditions is complicated by the multiple conditions for \( P_2 \) and \( P_3 \). These,
however, are required by the possibility of excess capacity and, in general, are simple to account for. The optimal price (in cents per kwh) in the base period ($i = 1$) is

$$P_1 = b_1 + \frac{\lambda_1}{h_1},$$

where $b_1$ is the marginal operating cost (that is, the cost of generating one more kwh using base generators), while $\lambda_1/h_1$ is the marginal capacity cost (on an hourly basis). If there is no excess base capacity ($C_1 = x_{11}$), then $\lambda_1 = (h_2 + h_3)(b_1 - b_2) + B_1 - B_2$, following Wenders. By assumption, $b_1 < b_2$, but $\lambda_1 \geq 0$. The marginal capacity cost is the cost of adding one kw of intermediate capacity and the savings in operating costs from using that additional base capacity during the intermediate and peak periods.

If there is excess capacity, however, then $\lambda_1 = 0$, and base period price is

$$P_1 = b_1,$$

that is, the price is strictly equal to marginal operating cost.

The optimal price in the intermediate period is defined by two equations:

$$P_2 = b_2 + \frac{\lambda_2}{h_2};$$

$$P_2 = b_1 + \frac{\lambda_2}{h_2} + \frac{\lambda_4}{h_2}.$$

The first equation is directly analogous to the optimal $P_1$. The optimal price is equal to the marginal operating cost of intermediate generators, $b_2$, plus the marginal capacity cost of intermediate generators, $\lambda_2/h_2$. Again, following Wenders, $\lambda_2 = h_2(b_2 - b_3) + B_2 - B_3$ and $\lambda_2 \geq 0$. The marginal capacity cost is the cost of one kw of intermediate capacity less the cost of building and operating one kw of peaking capacity. If there is excess capacity in the intermediate period, then $\lambda_2 = 0$ and $P_2 = b_2$. Note, however, that excess capacity in the intermediate period can be caused by excess base capacity. That is, if $C_1 > x_{11}$ (base generating capacity exceeds base load) and $C_2 = x_2$ (intermediate generating capacity equals intermediate load), then $C_1 + C_2 > x_1 + x_2$, and there is excess capacity in the intermediate period.

Assuming that the second equation produces the same price as the first equation,

$$b_2 + (\lambda_2 / h_2) = b_1 + (\lambda_2 / h_2) + (\lambda_4 / h_2),$$

and

$$\lambda_4 / h_2 = b_2 - b_1.$$

In this case, the Lagrangian multiplier, $\lambda_4$, is the difference between the marginal operating costs of intermediate and base generators and can be interpreted as the value to the utility (and the rate payers) of having one more kw of base generation available for meeting intermediate load.

In two cases, however, the second equation has a different implication. If $C_1 = x_{11}$, then all of the base and intermediate load is being met by base generators. Not only does $\lambda_4 = 0$, but also there is no generation from intermediate generators. The first equation for $P_2$ would be inoperative, and $P_2 = b_1$, the operating cost of the base generators. It is also possible that $C_1 = x_{12}$ and $x_{12} = 0$. That is, base capacity just equals base plus intermediate load. In this case, $\lambda_4$ has the same interpretation as $\lambda_1$, that is, $\lambda_4 = (h_2 + h_3)(b_1 - b_2) + B_1 - B_2$, and $P_2$ equals the marginal operating cost plus marginal capacity cost of base generators.

Turning to the peak period, there are three equations defining the optimal price:

$$P_3 = b_3 + (\lambda_3 / h_3);$$

$$P_3 = b_1 + (\lambda_3 / h_3) + (\lambda_5 / h_3);$$

$$P_3 = b_2 + (\lambda_3 / h_3) + (\lambda_6 / h_3).$$

*From the condition that $\lambda_4 > 0$ it follows that

$$b_1 + \frac{(B_1 - B_2 - h_2(b_2 - b_1))}{h_3} > b_2;$$

In order for $P_2 < b_2$ in this case,

$$b_1 + \frac{(B_1 - B_2 - h_2(b_2 - b_1))}{2h_2} < b_2$$

must hold.
Since there are no higher priced generators to be offset by using peaking generators, the marginal capacity cost in the first equation is simply the cost per kw of a peaking generator \( (B_3) \). Therefore, \( P_3 = b_3 + (B_3 / h_3) \) and, if there is excess capacity in the peak period, \( P_3 = b_3 \). The interpretation of the remaining equations follows the discussion of the intermediate period price.

While a full consideration of the optimality conditions for various regimes of excess capacity may prove useful, for the purposes of this paper only one case is discussed. In this case there exists excess base generating capacity \( (C_1 > x_{11}) \), but there is not enough surplus base capacity to displace intermediate and peaking capacity fully (that is, \( x_{22} > 0, x_{33} > 0 \)). At the same time, the excess base capacity does create excess capacity in the intermediate and peak periods. There are no apriori grounds for determining if, in fact, \( P_2 \) in this case is less than \( b_2 \). If not, then excess base capacity creates an interesting anomaly that warrants future analysis.

To summarize, optimal prices in the absence of excess capacity are

\[
P_1 = b_1 + \frac{B_1 - B_2 + (h_2 + h_3)(b_1 - b_2)}{h_1},
\]

\[
P_2 = b_2 + \frac{B_2 - B_3 + h_3(b_2 - b_3)}{h_2},
\]

\[
P_3 = b_3 + \frac{B_3}{h_3}.
\]

With excess capacity, optimal prices are

\[
P_1 = b_1,
\]

\[
P_2 = b_2,
\]

\[
P_3 = b_3.
\]

Finally, it is easy to show that with no excess capacity \( (C_1 = x_{11}, C_2 = x_{22}, C_3 = x_{33}) \) the optimal prices cover all capacity and operating costs. Since \( C_1 = x_{11}, C_1 = x_{12}, \) and \( C_1 = x_{13} \), then \( C_1 = x_{22} \) means that \( C_2 = x_{22} \). Substituting the \( C_1 \)'s for the appropriate \( x_{ij} \)'s, total revenue (TR) is given by

\[
TR = h_1 b_1 C_1 + B_1 C_1 - B_2 C_1 + (h_2 + h_3)(b_1 - b_2)C_1 \\
+ h_2 b_2 (C_1 + C_2) + B_2 (C_1 + C_2) - B_3 (C_1 + C_2)
+ h_3 b_3 (C_1 + C_2 + C_3)
+ B_3 (C_1 + C_2 + C_3).
\]

Simplifying and collecting terms,

\[
TR = h_1 b_1 C_1 + h_2 b_2 (C_1 + b_2 C_2) + h_3 (h_1 C_1 + b_2 C_2 + b_3 C_3)
+ B_1 C_1 + B_2 C_2 + B_3 C_3,
\]

which is total cost.

It follows, therefore that when there is excess capacity, total revenue will be less than total cost.
References


will review an experiment sponsored by the Federal Energy Regulatory Commission (FERC) examining the appropriateness of traditional regulatory oversight of certain transactions within the bulk power marketplace. I will also sketch some of the lessons being learned on the job regarding interchange strategy in a competitive market. Let us first consider the emerging dimensions of competition.

**Competitive Forces**

A number of interrelated factors are causing competitive market pressures, some of which are noted below.

- Reduced load growth projections and committed resource expansion plans have led to "uncommitted" capacity.
- Gas market deregulation has heightened intersource competition.
- Alternative generation sources and PURPA have had substantial effects.
- Changes in consumer behavior and product efficiency improvements have given new meaning to the consumer choice/product definition.
- Institutional momentum is a growing force.

While most of these are self-explanatory, a few comments are appropriate regarding changes in consumer behavior and institutional momentum. Not only are changes occurring in how energy is consumed, but also many customers desire a choice among suppliers. As an example, certain federal agencies are taking a strong policy stance regarding their ability to procure utility services regardless of state law which may legislate service territory boundaries or state public utility commission jurisdiction. Some industrial and commercial customers are turning to self-generation and want to wheel power from their generator to off-site loads. There also has been a rise in coordinated customer intervention in regulatory proceedings. We must recognize that customers are no longer just consumers of a product, but constituents who hold the power to limit utilities' freedom of action.

Institutional momentum is an extremely powerful force. A number of industries have gone through some form of deregulation during the last decade, and, while actual results may prove to be mixed, there is a general perceived degree of success by most individuals. The perception that there is a benefit to be gained by industrial reorganization can be a more compelling force than reality. In a recent survey of 102 state utility regulators, 101 indicated they believed...
the electric utility would go through some form of deregulation -- a rather strong presupposition.

Effectively, these competitive pressures are doubling the number of market channels with which utilities must deal. Previously, there were two or fringe competition between utilities to serve new loads and energy intersource competition, largely between gas/oil and electricity. Now there are at least four market channels: enhanced interutility competition to serve new and existing loads, greater energy intersource competition due to the "gas bubble" and gas market deregulation, alternative generation opportunities for electric consumers, and consumer product redefinition -- efficient appliances and equipment.

Changes in the first market channel -- enhanced interutility competition -- are apparent to those operating in the bulk power market. The rules of the game are changing due to economic realities. The cost of excess capacity to stockholders and captive customers is high and is driving many utilities to consider strategies previously discounted, including some product and price unbundling.

Within the second market channel, the current situation in the natural gas market has heightened the degree of competition in the fuel displacement segment of the bulk power market. It also significantly affects investment decisions by energy-consuming industries as to the form of energy they will consume.

The enactment of PURPA has opened a new market channel that entrepreneurs are aggressively pursuing to sell power both to utilities and/or to a utility's direct customers. PURPA implementation is causing economic inequities and market distortions and should be modified and discussed later. However, even repeal of PURPA would not cause this market channel to disappear -- the opportunities for "cream-skimming" in the electric utility business are too great.

The fourth market channel, much has been written about the fundamental change in philosophy from selling electricity to providing customer goods and services in the form of heat, light, and so forth. The vendors of appliances and equipment have recognized that by making their commodities more energy efficient, they can gain economic rents from the consumer by sharing the reduction in the electric bill. Clearly, competition from the producers of the appliances and equipment that consume electricity through this developing market channel.

Another element, potentially associated with the bridging of these market channels, is the development of entrepreneurial "brokerage" as a new concept to the industry, as a number of utilities have served as regional brokers in the economy energy market, but now new entrants are eyeing the game and the profit potential of the middleman.

As an example, Citizens' Energy hopes to serve as an independent power broker that will use its "profit" to develop small power projects to help the poor pay for energy. The group is seeking a declaratory order from the FERC that its "retail" transactions not be subject to regulation. This is a noble cause and puts the broker business "on the side of the angels." However, other profit-motivated entities are clearly watching to see how many barriers are in place for their future benefit by the FERC's handling of this filing.

The Southwest Bulk Power Market Experiment

With all of this activity occurring, the FERC sponsored an experiment in the southwest to see if a certain segment of the bulk power marketplace was sufficiently competitive to support rate-based regulatory oversight. This segment is the coordination services market. Coordination transactions embody a spectrum of commodities from economy energy to firm power, with both buyers and sellers having generation resources. Such transactions are normally made for economy or reliability purposes and do not involve commitments to serve load growth. I contrast coordination services with requirements service, which involves the sale of firm power on a long-term open-ended basis to either full or partial requirements customers where the customer has little or no generation and rates are set through a rigorous cost-of-service analysis. Such requirements service is similar in character to traditional retail service, except for the voltage level. Let's briefly discuss each market area to which the Southwest Bulk Power Market Experiment was injected.

Historically, the market area has had a significant amount of utility interchange. Since most utilities dispatch their own generation, economic interchange has been heavily relied on to use available generation more efficiently. Two-party agreements have been the standard contractual format, and the most prevalent form of interchange has been economy energy priced on a split-savings basis.

With the advent of competitive conditions, the "breakeven" areas have rapidly expanded. Conditions have changed quite significantly in the area, as well as in the rest of the United States. Ten years ago, rapidly expanding loads were forecast, and utilities embarked on coal and nuclear conversion and expansion through the 1970s to reduce dependence on natural gas and oil and to meet the projected demand. Transmission was built to move power from the new large remote generating units to the discrete load centers that were projected to grow so rapidly. When the loads did not materialize, projected large amounts of power were recovered in the coordination market. Certain utilities within the WSCC were still dependent on oil and natural gas, particularly in California. This led to an enhanced fuel displacement market.
The result was significant change in the character and structure of the bulk power marketplace. It was more competitive, and there were high economic stakes involved, particularly for the sellers. The market was transmission constrained, and we now find new transmission being driven more by coordination than by competition.

Finally, there was a general recognition that price and other terms for coordination sales are really driven by market forces which may only be guided by cost of service.

With that, let me provide a brief description of the experiment. In general, it represents an attempt to establish a quid pro quo between the participating utilities and the FERC. The utilities agreed to test the viability of an open and competitive market in certain coordination services, while the FERC agreed to provide more pricing flexibility for such services and explicit financial incentives to engage in off-system sales.

There are three experimental "treatments." The first is pricing flexibility. Economy and block energy transactions can be made at any price within a "zone of acceptability" ranging from 9 to 90 mills/kwh. As a seller, I have been consistently disappointed as to the end of the zone at which the price has tended to hover. The second treatment is a financial incentive whereby 25 percent of the FERC-allocated share of the profit from experiment transactions is retained by the seller. The third treatment is to ensure equal transmission access among participants so there will be ease of entry and exit in the marketplace. Transmission must be provided at established (embedded cost based) rates subject only to technical limits and pre-existing commitments.

Two measures of success for the experiment were identified: (1) Did the economic efficiency of the market improve, that is, did the experiment treatments lead to the production of power using fewer or less costly resources? (2) Did a competitive market exist in a performance or structural sense?

The Rand Corporation was retained by the FERC in the design of the experiment and to evaluate its operation. The Rand report covering the first year is now out, and I would summarize its basic conclusion as "no harm, no foul, with raisin still unresolved." To understand this bottom line, let us return to the three treatments and examine their effectiveness.

The pricing flexibility treatment was operative and did afford flexibility. However, this was occurring before the experiment through liberal interpretation of existing tariffs or by quickly drawn up agreements to meet a certain situation. These agreements were accepted by the FERC's de facto eased regulatory oversight policy.

The finally profit-retention incentive had no effect on the experiment because it did not really exist. First, sellers were only able to retain 25 percent of that portion of revenue allocated to the seller's FERC class, which averaged less than 10 percent. Second, it was only in effect for a portion of the experiment and was never in effect for my company. Finally, the experiment includes only a small fraction of the total transaction volume in the marketplace, with less than 10 percent of all coordination transactions made occurring among experiment participants.

With respect to transmission service, very little was provided for a variety of reasons. In most instances, participants were directly interconnected, and third-party transmission service was not needed. When it was, previously existing transmission agreements were frequently used. This latter result could be interpreted to mean that existing arrangements provide adequate access, and stricter access rules are unnecessary, although I think that begs the question.

From a policy perspective, I draw the following conclusions from the experiment:

- The southwest operates within a short-term bulk power market which performs competitively.
- Provision of greater pricing flexibility does not reduce overall efficiency in the market and does not result in prices that deviate significantly from the competitive ideal.
- These results will not necessarily hold for all regional bulk power markets.
- No conclusions may be reached on the effectiveness of providing an incentive to trade through retention of a portion of the gains by the seller.
- The value of having greater transmission access requirements will not be determined by the experiment; the debate will continue.

In summary, the experiment was an essential element in moving institutional forces in the direction of allowing eased regulatory oversight. But it did not, in and of itself, generate any major results we did not already know. It was a necessary and useful exercise in legitimacy.

Institutional Impediments to Industry Competitive Response

Before considering interchange strategies, I think it is useful to review impediments to the industry's ability to compete in the transforming bulk power marketplace. Traditionally, the market has been comprised solely of interutility
transactions. Now PURPA machines thrive in this market, and we are confronted with the issue of common carrier and retail wheeling.

PURPA has created a new special-interest class of favored generators. They include some who favor interutility competition so they can get cheaper traditionally supplied electricity. Yet, they oppose having the buyback rates for cogenerators power determined through the competitive market. It is the latter which must occur because the former is already being thrust upon us. Application of an incremental cost may frequently result in a rate based on avoided cost is causing significant economic distortion through the setting of an inaccurate benchmark price -- the benchmark should be the market clearing price. Why should a utility be obligated to purchase at a lower price than a cogenerator whose facility is not yet constructed when more reliable power is available from existing resources of another utility at 5 cents/kwh? To the extent cogeneration offers inherent economic efficiency through better resource utilization, this should be reflected in lower buyback rates rather than a higher rate forcing subsidization of the cogenerator by a utility's customers. However, utilities are rapidly learning that in many instances the greater risk is not artificially high buyback rates, but load displacement by cogenerators serving their own load and potentially attempting to sell to other retail customers through the use of the utility's transmission and distribution system.

Another player in this expanding marketplace is the publicly owned system, which currently has preference access to low cost power from federal marketing agencies. Many public systems, particularly the REAs, were conceived to bring power to rural America. Some are now using their access to subsidized hydro power to attract industry to their service territories. Clearly, public power is, and should be, a major force in the bulk power market. But I cannot rationalize why the nation's taxpayers should subsidize the marketing effort of some public utilities, for this market segment requires service, not just market power. Requirements customers, like many retail customers, want more control over their economic lives and want to exercise choice. Such choice is a major element in the coordination services market, but not in the requirements service, at least not historically. The distinction between these market segments must be maintained, and utilities cannot be held responsible for traditional service obligations when the customer will not honor the obligation to pay.

Another major impediment, which has technical and institutional elements of concern, is the issue of transmission access. Transmission is a complex topic, and our language makes it even more so. Just try to give a simple definition of the difference between pipelines and electric transmission lines. The emerging economic logic of "wheeling power versus money" is critical to ensuring overall economic efficiency, which we need to remind ourselves is the goal. The distinction between wheeling power and money is one of true economic substance. Efficient wheeling ensures that the lowest cost (not necessarily price) resources are used. The desire to wheel power on the basis of embedded power cost differentials rather than true application of (2), Application of an incremental cost may frequently result in an inefficient resource utilization and to the transmission system performing a welfare function of income redistribution, that is, wheeling money. The FERC should be commended for being conscious of the issue in recognizing that transmission pricing is the issue. However, utilities must recognize that the economic efficiency rationale may justify more flexible transmission access. Moreover, the political reality may mean that some form of wheeling obligation is necessary for utilities to gain approval of greater pricing flexibility -- a key to being able to compete.

Opposition to pricing flexibility will partially stem from the implication of price discrimination. Such discrimination does occur in a competitive market -- just look at the myriad of fares airlines offer based on the market segment -- business, vacation, weekend, and so forth. In a competitive market the time path of cost recovery will be different from that under regulation, and utilities must obtain the pricing flexibility to handle this.

Interchange Strategy in a Competitive Market

We have discussed how competitive market forces are changing the industry, the experiment as an effort to legitimate the competitive bulk power market's existence, and certain barriers that impede the industry's ability to compete. Independent of how these issues are resolved, utilities still must put in place the tactical strategies that will allow it to survive the natural market selection process. Consequently, we would now like to turn to the issue of interchange strategy in a competitive environment. In this discussion, I will take the perspective of a seller.

A key ingredient for any marketing strategy is to KNOW YOUR CUSTOMER. The more one knows about a prospective customer in terms of goals, alternatives, and weaknesses, the better one will be able to design a power supply to meet his needs. While it may sound corny, if his needs are met and he is successful, the seller will also be successful.

In the bulk power market, knowing the customer means much more than cursory review of the load and resource tables of potential utility customers. It means understanding the position in which the customer wants to be and performing
explicit analysis on the customer's near- and long-term load, resource and financial positions, and regulatory environment. Specifically, one should ask the following kinds of questions.

- How reasonable are the customer's load projections (demand and energy patterns), and what degree of risk is associated with them?

- What other power supply alternatives are available to the customer, and what are the associated economics?

- In what regulatory climate does the customer exist?

- What are the customer's preferences between quality/reliability and price?

- What is the customer's attitude toward investment and business risk?

- In what financial and rate position is the customer expected to be during the relevant time frame?

- What other physical or institutional constraints may need to be overcome to effect a transaction?

Attempting to answer these questions creates a complex process. It will include detailed financial analysis of various power supply packages not just on the seller but on the customer.

In performing this kind of analysis, obviously one must determine the company's objectives and capabilities. This should lead to targeting certain kinds of markets that are potentially successful. This is the essence of market segmentation. Whether due to a strategic decision or economic necessity, one must decide to participate in a number of market segments or concentrate on just a few. The important point is to recognize that market segments must be viewed as unique classifications of customers, each with their own needs and desires, and must be treated individually.

The commitment to participate aggressively in the bulk power market can lead to some fundamental changes in a utility's organization and mode of conducting business. Certain traditional staff areas may be reorganized as functional support to the market planners and implementers. For example, many generation and transmission planning departments are finding that an increasing amount of their effort is concentrated on developing and evaluating power supply packages tailored for them as a buyer, or by them as a seller, instead of the more traditional generation and transmission expansion planning activities.

A greater focus on market planning may lead to the use of "product managers" along the lines of Proctor & Gamble to best develop plans and approaches for meeting the needs of a specific targeted market segment. The type and use of analytic tools to evaluate alternatives will also change. Accounting and management information systems will need to be geared to provide profitability accounting so that costs, revenues, and margins can be examined by market segment and product. The decision-making process of utility executives changes in recognition of the need to respond more quickly to competitive threats and opportunities, particularly given a more uncertain future. Clearly, utilities must shorten their "turning radius" in adapting to changed circumstances. Continual reliance on lead times of ten to fifteen years spells doom for the industry.

Summary

As an area of our business on the edge of change, the bulk power market is certain to experience other types of experiments and pricing flexibility, including transmission pricing. Several can already be seen on the horizon. As an example, certain utilities are attempting to isolate the wholesale elements of their business even to the point of creating new companies and attempting to take them private. As a second example, certain kinds of unique joint ventures are being considered for the development of future generation and even transmission resources in a more entrepreneurial style. Experiments involving value-based transmission pricing arrangements are being seriously discussed in different parts of the country. Such experimentation should be encouraged so that legislative and regulatory change to create a more efficient industry organization can occur, if necessary, with the benefit of relevant information from such focused experimentation.

In summary, I believe there has now been an intellectual climate established regarding at least the partial deregulation of the electric utility industry, focused on the bulk power market, and the subsequent encouragement of competitive market forces that is irreversible. How utilities respond to this will dictate their survival, or at least their structure, in light of the expansion in number and size of the relevant market channels.

Notes


Jeffry Sterba's paper provides an insightful discussion of the forces that are making wholesale and retail electricity markets more competitive. To his list, I would add one other development, the growth in the availability of wheeling service. Between 1961 and 1983 it is estimated that the amount of electricity wheeled increased by approximately 1,200 percent, while total electricity sales increased by about 200 percent. Clearly, the increase in voluntary wheeling has produced more competitive bulk power markets. Most of this wheeling is performed by and for integrated utilities. Voluntary wheeling for qualifying facilities and industrial and wholesale requirements customers is less common. Without major legislative and regulatory initiatives, utility customers and independent generators will generally not get access to wheeling. If they do get access, we can expect a quantum jump in competition in the electric utility industry.

I was intrigued by Sterba's observation that deregulation preceded competition in the transportation, communications, and banking industries but that the opposite is happening in the electric utility industry. I think the accuracy of this observation depends on how one defines deregulation. It is correct if deregulation is defined as the explicit...
removal of federal and state legal authority to regulate the price charged for electricity sales. It is incorrect to argue that deregulation is more broadly to include the granting of substantial de facto pricing flexibility by regulatory agencies.

At the wholesale level, the Federal Energy Regulatory Commission (FERC) has allowed investor-owned utilities substantial flexibility in setting prices for shorter term wholesale bulk power transactions. The commission does not require such transactions to be based on long-term rates or on regulated rates for utility service. In recent years, the FERC has set price ceilings above market prices for many shorter term bulk power sales. Most industry observers probably agree that this looser form of regulation has facilitated the growth in bulk power transactions among utilities. Presumably, this prompted Professor Paul Joskow's recent recommendation that the FERC should "formalize what has been an ongoing... experiment with substantial de facto deregulation of wholesale coordination transactions."

I found Sterba's discussion of the Southwest Bulk Power Market experiment to be the most interesting part of the paper. The reader should be forewarned that Sterba and I probably cannot be viewed as objective observers of the Southwest experiment. Jeff was chairman of the administrative committee of the utility participants, and I worked on the staff of the Southwestern Power Pool that negotiated and monitored the experiment for the FERC. Given our closeness to the experiment (albeit on different sides of the fence), we probably lack the perspective to assess it objectively. With that warning in place, I would like to make a few observations.

First, the experiment did not answer all questions relating to competition in the electric utility industry. It involved only two bulk power commodities, economy and block energy. Moreover, only electric utilities participated. If the commission or Congress decides that large customers and independent power generators should be allowed to participate in bulk power markets, then certain policy questions will need to be addressed: Is it appropriate to impose conditions or compensation arrangements on customers who want to change utility suppliers? Who should be accountable for uncompensated fixed costs that were incurred to serve a customer when that customer leaves the system? Do utilities have a residual obligation to serve customers in their service area who have switched to another supplier and then want to return to their original supplier? If service is obtained from a remote supplier, does the contiguous utility have an obligation to provide control and scheduling service? If so, how should it be priced? These questions were not considered in the Southwest experiment.

Second, Sterba is correct in pointing out that the actual experiment was not the planned experiment. The latter envisioned three treatments -- pricing flexibility, profit retention, and improved transmission access. I think it is fair to conclude that pricing flexibility was the only treatment that "took" in a significant way. In retrospect this was a blessing in disguise. It eliminated a collinear problem by allowing the effect of the experiment to be attributed to one rather than three changes.

Third, I think the major policy significance of the experiment is that the "sky did not fall down." Price regulation was effectively removed during the experiment.

3. The prices charged by municipal, cooperative, and other public systems for wholesale sales are generally not controlled by any regulatory agency.


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Part Seven

The Impact of the FERC
Rulemaking on Natural Gas
"I've always loved the free enterprise system. But I find it harder to tolerate competition!" These words might have been spoken by the chief operating officer of an interstate natural gas pipeline company upon learning of a recent Federal Energy Regulatory Commission (FERC) decision, Order No. 436, which requires a pipeline offering transportation services for natural gas to provide those services on a nondiscriminatory basis. Prior to this decision, interstate pipelines operated in a regulatory climate that allowed them to maximize profits at the expense of certain customers -- notably, residential customers served by local distribution companies. This goal was achieved through the pipelines' participation in two transportation programs established by orders of the FERC.

The Special Marketing Program (SMP) and the blanket certificate program allowed customers with the ability to switch to an alternate fuel (usually oil) to avoid purchases of an interstate pipeline's high priced system supply of natural gas. These favored customers were able to negotiate directly with producers for low priced natural gas, which was then transported over interstate pipelines at a total cost far below the price paid for gas purchased from the pipeline's own system supply.

The Maryland People's Counsel (MPC), representing residential consumers of natural gas, challenged these two
programs, arguing that they were discriminatory, anticompetitive, and sanctioned a classic abuse of monopoly power. The PUC argued that the programs allowed a pipeline to segment its markets, charging supra-competitive prices to residential and other "captive" customers served by local distribution companies (LDCs), while obtaining transportation revenues from customers with alternate fuel capability, who were now able to contract for gas that was less expensive than the pipeline company's system supply and to have that gas transported by the pipeline.

In May 1985 the U.S. Court of Appeals for the District of Columbia Circuit rescued these "captive" customers, issuing a series of three opinions overturning the commission's SNP and blanket certificate proceedings. In response to the court's mandate that such programs be conditioned on nondiscriminatory access to transportation services, the commission, on October 9, 1985, issued Order No. 436. This paper considers whether Order No. 436 appropriately addresses the price discrimination previously sanctioned by the SNP and blanket certificate programs.

A Brief Historical Perspective

The Natural Gas Act (NGA) allows pipelines to transport gas from producers to end-users and distributors in other states and to purchase gas and resell it on their own account. While all purchasers were not locked into buying the high priced system supply of pipelines. Industrial customers with the ability to shift to alternate fuels, usually oil, could avoid such purchases. Their defection imposed two additional burdens on remaining captive customers. First, the fixed cost component of rates increased, since those costs would be spread among a smaller number of customers. Second, the gas cost component of rates continued to rise above the already inflated levels, since the pipelines were now taking less gas, resulting in substantially increased take-or-pay liabilities.

The 1978 predictions of 1985 markets, on which the NGPA was based, were in error, resulting in a natural gas surplus that still exists today. Factors contributing to the surplus include increased wellhead prices, impending total decontrol, greater energy conservation, and lower prices of competing fuels. The ceiling prices for all significant categories of post-1977 gas are now well above market levels for gas as determined by the energy equivalent price of fuel oil and by what arm's length buyers and sellers are currently considering for the pipeline. The surplus also led to the take-or-pay problems now facing many pipelines. During 1979-1981, pipelines entered into long-term contracts for NGPA and regulated gas at volumes and prices based on 1978 expectations. As gas prices increased, these contracts created the take-or-pay problem because many contracts obligated pipelines to take the gas at historically unheard of levels of 75-90 percent of the annual production level.

The Special Marketing Program

On June 3, 1983, the Columbia Gas Transmission Corporation and Exxon approached the commission with an application seeking
approval of a special marketing program. Columbia agreed to release its contract rights with respect to certain categories of gas and to transport the released gas to direct purchasers on Columbia's pipeline system in exchange for Exxon's agreement to credit the volumes of released gas sold against Columbia's takeable capacity. Columbia requested a temporary certificate of public convenience and necessity to transport the released gas pursuant to Section 7(c) of the NGA. Participation in the program was limited to those industrial customers who could use alternate fuels, to prevent a plant closing, or to reopen a closed plant.

The commission granted the requested certificate with several important and somewhat surprising conditions. Unlike the supply-side obligations of Columbia's suppliers, not just Exxon, were allowed to participate in the SMP. Second, the commission required the cost of the released gas to equal or exceed the average cost of gas on the Columbia system. It is important to remember that Columbia did not set the price the new purchasers paid for the released gas; the new sales were at prices significantly below that of the pipeline's system supply gas. Finally, and most important, the commission established a finite, discrete set of purchasers eligible to buy the low cost released gas and excluded all other customers. Purchasers of released gas were limited to: (1) new loads not previously served by natural gas; or (2) requirements which were or would otherwise be served by (a) alternate fuels; (b) producer direct sales arrangements; (c) gas made available pursuant to sales programs or other similar programs; (d) gas sold by pipelines under special discount rates, or an off system sale; or (e) propane or synthetic natural gas.\footnote{The commission's ostensible justification for its discriminatory programs was to increase the total amount of gas moving through the pipeline, thereby increasing the volumes over which fixed costs could be spread, resulting in lower rates to all customers. In addition, the commission argued that these programs would reduce take-or-pay liabilities. However, as discussed later, the commission ignored evidence which showed that captive customers and ultimately the industry itself would be harmed by this approach.}

The Blanket Certificate Program

In July 1983 the commission issued Order Nos. 234-B and 319, which provided pipelines with broad new marketing authority.\footnote{The commission utilized Section 7(c)(2) of the NGA to expand the transportation authority of interstate pipelines. This was one of two significant changes made in 1983. The other was Section 319 streamlined certain procedures and authorized blanket certificates permitting transportation to "high priority" end-users for five to ten years. These changes were relatively uncontroversial. Order No. 234-B, however, expanded the category of end-users eligible for direct sales gas by permitting transportation, pursuant to a blanket certificate, for any end-user, including boiler fuel users. This transportation was Columbia's takeable capacity for 120 days before running authorization could be obtained pursuant to notice and protest procedures. Low priority end-users were included in the blanket certificate program for a two-year "extension period" ending June 20, 1985. The commission refused to conduct evidentiary hearings prior to promulgating these rules and relied instead on several limited justifications. First, it reviewed the current conditions in the gas industry, including rising prices, falling demand, fixed contract obligations, and the pipelines' "seeming" inability to reduce costs to meet competition with alternate fuels. The commission did not, however, examine the reasons behind these justifications, and did not explain how these problems would be alleviated by segmenting the pipeline market. Second, the commission stated that the rule shielded captive customers from increased fixed cost burdens. Third, the commission stated that the rule would stimulate exploration and development. Finally, and inscrutably, it stated that the rule encouraged pipelines to adopt gas purchasing practices which would keep delivered gas prices competitive, even to those who remained captive to the pipeline's system supply. The Arguments of Maryland People's Counsel MPC vigorously opposed the SMP program; it was precluded from effectively opposing the blanket certificate program since there was no prior notice of the commission's intended action. The basic objection voiced by MPC was that the two programs sanctioned a classic abuse of monopoly power, since they allowed the pipelines to segment their markets between captive and noncaptive customers. The former -- including residential and small commercial customers -- were held hostage to the pipeline's high priced system supply gas; the latter -- industrial customers with the ability to switch alternate fuel sources were allowed to seek low cost gas supplies and to have the pipeline transport such gas for their use. The pipelines were able to sell their overpriced gas to captive customers and to obtain transportation revenues from customers who would have otherwise been served from the system. Thus, the pipelines had the ideal means to maximize profits. It is axiomatic that such a scheme thwarts competition and allows pipelines to engage in discrimination against captive customers, who cannot respond by switching fuels. MPC argued that the commission violated its statutory mandate by approving certificates which would cause unjustified rate increases to captive customers.}
consumers, by failing to consider the antitrust implications of its actions, and by approving programs that were unduly discriminatory and unlawful.9 The NGA, of course, does not prohibit all discrimination, only that which is unreasonable.10 With respect to the SMP, the commission, in the absence of the released gas program, declared that it was discriminatory.11 In order to exclude captive markets from the released gas program, therefore, the commission needed a reasonable basis. It offered three justifications.

MPC argued that the primary justification SMP was that it prevented core market competition between pipelines. MPC argued, first to the commission and later to the court, that the program had not been established to exclude the possibility of any competitive advantages to smaller customers that included captive customers. The commission's participation could further mitigate take-or-pay liabilities and thus further increase the fixed cost contribution resulting from the transportation of released gas. Moreover, MPC argued that core market competition would not necessarily be harmful and, indeed, that any increased fixed cost burden placed on captive customers would be outweighed by the downward pressure on all gas prices resulting from true competition in the marketplace.

The commission's second justification was based on the belief that captive customers would benefit from the fixed cost contribution resulting from the transportation and releasing of released gas to all customers in the program. In this finding was the conclusion that the pipeline would be allowed to recover all fixed operating costs in rates. However, as experience has shown, there is no factual basis to support such a view.12 The commission further concluded that captive customers would benefit from mitigation of take-or-pay exposure, which presumed that customers, not shareholders, would bear any liability associated with take-or-pay obligations. Again, this presumption was not based on fact, and the program maintained that proration occasioned by imprudent management should be borne by the stockholders. Moreover, MPC argued that any such benefits, including mitigation of take-or-pay liabilities, could only be realized if access to the released gas were available to all customers.

The third justification advanced by the commission was that its program was "experimental." MPC argued that since discrimination was present, the commission was required to assess whether it was unlawful pursuant to the NGA before implementing the discriminatory program on an experimental basis.

MPC raised similar arguments with respect to the blanket certificate program. It argued that the commission's

The Opinions of the D.C. Appellate Court

In mid-1985 the court issued opinions in the three cases brought by MPC challenging the exclusion of captive customers from the SMP and blanket certificate programs. MPC I dealt with MPC's challenge to the approval of the original SMP program.13 MPC II dealt with the filings of the blanket certificate program.14 MPC III dealt with the successor SMP order, which extended the original program with a slight variation.15 The successor order allowed for negligible participation in the program by captive customers, thereby requiring them to nominate and purchase up to 10 percent of their firm contractual entitlement for system supply pursuant to the SMP.

MPC I

In MPC I the court succinctly framed the issue: Did the commission set forth a reasonable basis for believing that the program maintained it approved would benefit all ratepayers? The court carefully analyzed each of the commission's proffered rationales in support of its eligibility restrictions. With respect to the fixed cost spreading rationale, the court agreed that it was based on the fact that if released gas were transported over a pipeline system, fixed costs would be spread over greater volumes of gas. However, the court also agreed with MPC that the commission failed to explain why such savings would not accrue in larger proportions absent eligibility restrictions that lie subsequent to SMP sales. Instead, the court noted that the commission's counsel apparently conceded this point at oral argument.
The court next addressed the contention that the SMP program reduced potential take-or-pay liabilities. The court recognized three shortcomings with respect to this justification. First, such mitigation might not be a significant benefit to captive customers because the question of whether the customers or the shareholders were responsible for this liability was unresolved. Second, the pipelines themselves had raised force majorure arguments against producers with regard to their "take-or-pay" liabilities, so that such liability might not even exist. Third, mitigation of take-or-pay exposure would occur even in the absence of eligibility restrictions.

The court further explained that even if the choice were between gas moving under an SMP with restrictions and no gas moving under an open access SMP, the commission did not establish sufficient cost spreading justifications for its approval of the restrictions. The court directly addressed the backward vertical integration argument, stating there were significant incentives for pipelines to pay above-market prices, thus producing increased profits to their affiliates. The court found that MPC's argument that the SMP enabled pipelines to price discriminate by allowing them to sell their own overpriced gas to captive consumers while still retaining fuel switchable customers by serving them at market rates, was simply not answered.

The court also found that the commission had not answered MPC's argument that savings to captive customers from any cost spreading resulting from a restricted SMP would be dwarfed by savings that could be realized if captive customers were allowed to participate. The court recognized that, because competitive costs were relevant to the public convenience and necessity standard of Section 7 of the NGA and that avoidance of the antitrust implications was puzzling in light of the commission's prior and subsequent recognition of the importance of these implications.

Finally, the court addressed the commission's main argument in defense of its restrictions -- that competition between pipelines for each other's "core" or "captive" markets would not necessarily be in the public interest. The court held that this reasoning "plainly" could not support the regulation. The court agreed with the commission's argument that competition could have avoided this problem by conditioning the certificates so that a pipeline would transport only gas released from its own system supply to its own captive customers. Moreover, the court opined that even if competition between pipelines could realize some benefits, it might be found that the downward pressure exerted on gas prices by competition would outweigh any fixed cost burden. The court labeled as "ridiculous" the commission's argument that there was nothing in the SMP to stop producers from reducing prices to Columbia for gas that they had already contracted to sell to Columbia.16

The court concluded:

It would be an exaggeration to say that this petition for review has required us to evaluate whether the Commission had, if not the better side, at least the reasonable side, of the arguments advanced by MPC over the effects of these orders. On a number of obviously significant points that MPC raised, there is simply no argument to evaluate: The Commission proceeded on its course with no comment, or with comment that was patently unresponsive.17

As relief, the court issued an order to show cause why the commission orders extending the SMP should not be vacated and remanded.

MPC II

MPC II dealt with the blanket certificate program. In this case, the court found that the commission had again expanded interstate pipelines' authority for the carriage of direct sale gas and again excluded captive customers without a reasonable basis. The court concluded that the commission had not adequately attended to its prime constituency—the consumers the NGA was designed to protect from exploitation at the hands of natural gas companies. The commission's principal shortcoming was its failure to evaluate the anti-competitive consequences of its actions. The court held that antitrust policy was a relevant consideration.

The court also rejected each rationale offered by the commission in support of its discriminatory program. The court rejected the fixed cost savings justification because the commission's claim that such benefits would not increase if blanket transportation were conditioned on nondiscriminatory access. It further held that the commission failed to answer MPC's contention that fixed costs were insignificant when compared to the benefits to captive customers allowed by being allowed to participate in spot market transactions.

Finally, the court rejected the commission's conclusion that the blanket certificate program was likely to keep wellhead gas prices responsive to reductions in the burner-tip price of other fuels by ensuring that price competition from competing fuels would be felt at the wellhead. Indeed, the court recognized that if the pipelines refused to transport direct sales gas on a nondiscriminatory basis, the result
would be presumably still greater surpluses of gas at the wellhead -- the clearest possible signal to producers that their long-term contract prices were too high. The commission's statement that the program would create an incentive for pipelines to adopt gas purchasing practices which would keep their delivered prices competitive was dismissed as a "Delphic scenario."

The court vacated the order to the extent that it allowed transshipment of dual-fuel switchable gas service without requiring pipelines to furnish the same service to local distribution companies and captive customers on nondiscriminatory terms. The court remanded the case, directing the commission to consider fully and reasonably analyze the competitive concerns advanced by MPC.

MPC III

In the final case, the court held that the commission order extending the SMP was infected by the same failure to come to grips with the highly relevant considerations found in MPC I. The court declared all SMPs invalid -- not just Columbia's.

The commission's attempt to temper its decision to exclude captive customers from the SMP by allowing limited participation (up to 10 percent of their firm contractual entitlement) was found to be an inadequate solution to the criticisms found in MPC I. The court stated that arguments as "massively significant" as those raised by MPC merited convincingly reasoned rejection, and this the commission had still not furnished. The justifications cited by the commission, such as take-or-pay roller, fixed cost spreading, and stimulation of exploration and development, were rejected -- as they had been in MPC I -- because the commission failed to explain why such benefits would not exist in the absence of eligibility restrictions, and why they would not be dwarfed by the savings that would accrue to the benefit of consumers if there were competition in the marketplace.

The court concluded that the commission's findings with respect to the new SMP programs contained "identical lapses of logic and evidence" as its findings with respect to the original program. The court held that if the commission wished to retain discriminatory SMPs in some form after October 31, 1985, it could do so only if it could demonstrate that MPC's arguments were unfounded or outweighed by other relevant considerations.

Order No. 436

On October 9, 1985, the commission issued Order No. 436 -- its landmark order concerning the regulation of natural gas pipelines after partial wellhead decontrol. The commission "took to heart" the court's findings in MPC I, II, and MPC III, stating it was issuing the rule to comply not only with the court's mandate but also with the mandate of the NGA and NGPA as well.

The commission's stated purpose for the new rule is to assure that commodity and transmission prices for natural gas between the wellhead and the burner-tip are clear, accurate, and consistent with the NGA's requirement that rates and practices be just, reasonable, and not unduly discriminatory. The final rule also secures for consumers the benefits of competition in natural gas markets consistent with both the NGA and the NGPA. These goals are achieved by establishing a framework for setting just and reasonable rates and practices for the sale and transportation of natural gas in interstate commerce and by reasonably conditioning self-implementing interstate transportation services pursuant to the NGA and the NGPA.

Section IV of Order No. 436 contains the commission's analyses of the transportation issue. Revisiting and adopting its views as expressed in the original SMP and blanket certificate orders, the commission states that it is strongly committed to conditioning natural gas transportation on nondiscriminatory access. Indeed, it describes the nondiscriminatory access provisions as the "cornerstone" of the rule. Non-discriminatory access to transportation services assures that the benefits of competitively priced gas supplies and transportation services are available to the broadest number of consumers. The commission finally adopted MPC's argument that the limited benefits of restricted access to gas transportation services are far outweighed by the benefits conferred by open competition. Indeed, the commission states that nondiscriminatory access helps to achieve a non-regulatory goal -- maximizing throughput in order to spread fixed costs over the greatest number of customers. Finally, the commission recognizes that allowing pipelines to discriminate merrily against or to exclude certain consumers from transportation services is inconsistent with the fundamental goals of consumer protection and competition as set forth in the NGA and NGPA.

From the policy standpoint, therefore, the commission squarely addressed the findings of the court with respect to the discriminatory and anticompetitive effects of restricted access to pipeline transportation services. However, the
methods for implementing these policies, as set forth in Order No. 436, could prove to be detrimental to the concept of nondiscriminatory access. These concerns -- and others -- were addressed in MRC’s application for rehearing of Order No. 436.

MRC’s major concern is the 25 percent per annum limitation on an LDC’s right to convert its firm sales entitlements. The final rule allows firm sales customers to reduce and/or convert firm sales entitlements to firm. The conversion option allows the firm sales customer who still wishes to contract for firm capacity to unbundl firm transportation capacity from firm gas sales service. This provision is central to the concept of nondiscriminatory access. Without the opportunity to obtain transportation for its firm supply on a status equal to that of its firm purchases from the pipeline, nondiscriminatory access has no real meaning for an LDC. For an LDC effective competition for low cost gas for its system supply customers, it is essential that it be guaranteed firm capacity in the pipe to transport such gas. Otherwise, it will be unable to meet its public service obligations. LDCs pay for this firm capacity and should be allowed to utilize it in a manner that minimizes their cost of gas. The commission-recognized these facts and provided a conversion option to any customer willing to pay a reservation charge for such service.

Conversion customers have the same priority and quality of transportation service as they have with respect to their firm sales agreements.

MPC raised two concerns with respect to the conversion option. First, it could not be exercised in the first three LDCs for the 1985-1986 heating season. While others could immediately search out the most competitive source of gas, LDCs could not use any of their reserved firm capacity to receive gas from merchants other than pipelines until April 1, 1986. Second, as a result of the 25 percent limitation, LDCs cannot complete the transition to a competitive commodity market for another four years.

MPC raised other, more technical, issues with respect to the final rule in its application for rehearing. However, MRC recognized that Order No. 436 took a tremendous step in favor of a truly nondiscriminatory natural gas transportation program, one which, in theory, directly responds to the court’s criticisms.

On December 12, 1985, the commission issued Order No. 436A, in response to numerous requests for rehearing and clarification. While the order deals with many issues concerning all phases of the final rule, attention will again be focused on the commission’s treatment of nondiscriminatory access to transportation services.

With respect to policy considerations, the commission strongly reaffirmed its commitment to the goal of nondiscriminatory access to transportation services. It found that it possessed the requisite legal authority to order nondiscriminatory access. Various parties claimed that Order No. 436 constituted a coercive, involuntary program and that the condition of nondiscriminatory access mandated contract carriage, in derogation of congressional intent. The commission, in a short shrift of these arguments, stated that it was not mandating common carrier status by merely using its certificate conditioning authority as a means to establish just and reasonable rates to consumers of natural gas pursuant to both the NGA and legal precedent. Moreover, the commission correctly stated that the court’s opinion in MRC II recognized that the commission has the authority to impose nondiscriminatory access conditions on pipeline transportation.

The commission reiterated that a condition on a certificate where a pipeline voluntarily chooses to accept does not direct or mandate a pipeline to do anything.

The Commission cannot agree with those applicants that insist that it is not unduly discriminatory for a pipeline that transports gas to refuse to transport gas that displaces the pipeline’s sales. This is precisely what the court found objectionable in Maryland People’s Counsel v. FERC, 761 F.2d 780 (D.C. Cir., 1985). Pipelines that were willing to transport gas for their fuel-switchable customers were not required to transport for their captive sales customers that were incapable of switching fuels.

Indeed, in MRC I and MRC II the court directed the commission "to use its authority over natural gas transportation to provide carriage on a nondiscriminatory basis, if such transportation is to be offered at all." In conjunction with the court’s mandates, Order No. 436 established a comprehensive regulatory framework that provided the commission the opportunity to allow the commodity market for natural gas to develop in a competitive fashion.

The commission also addressed the conversion option, reemphasizing that firm sales customers would be denied the
most important tool available to them to compete with inter-
state pipelines seeking to bypass them and transport gas
directly to end-users. Stated otherwise, LDCs needed the
ability to book firm transportation capacity on the pipeline in
order to acquire suppliers that would enable them to compete.
The commission concluded that the reduction/conven-
tion option "is an indispensable element of nondiscriminatory
access to transportation."29 It rejected contentions that
the option was an unlawful, unilateral abrogation of a
pipeline's contractual rights by correctly observing that
Order No. 436 neither modified contracts on its own terms
nor established any unilateral right to do so.

Despite its strong policy commitment to the reduction/
conversion option, the commission retreated slightly with
respect to its implementation. Rather than allow 25 percent
of firm sales capacity to be converted to firm transportation
capacity over four years, the commission lengthened the phase-
in to five years, capping adjustments at 15 percent for each
of the first two years, 20 percent for the third year, and
25 percent for each of the last two years. It did so despite
its recognition that the conversion option provided firm
sales customers with a greater ability to purchase gas from
nontraditional suppliers and to have it transported on a
firm or interruptible basis. It also did so despite its
recognition that without the conversion option, interruptible
customers would be the primary, if not the exclusive, benefi-
ciaries of the "free-up" clause.

The commission's only stated justification for this
modification was that the new pipeline service options would
involve some structural changes within the industry. Feeling
that these changes might be somewhat disadvantageous to
some customers, the commission opted for a slightly more cautious
approach. MPC agrees with the commission with respect to the
necessity for the conversion option, but it also believes that
these reasons arguing in favor of such a policy argue in favor of a more rapid implementation of it.

Conclusions

To the extent they prevent pipeline companies from provid-
ing transportation services on a discriminatory basis, Orders
Nos. 436 and 436A promote economic efficiency and the mutual
interests of producers and consumers in a competitive and
efficient marketplace, undistorted by pipeline speculative
power. The orders will, over time, eliminate the discrimina-
tory pipeline practices that an ideologically diverse but
unanimous Court of Appeals panel found to be anticompetitive.
The orders eliminate opportunities for price discrimination,
monopoly pricing, and economic inefficiency. LDC access to
gas from numerous producers will create competition in the
supply market that will drive gas prices down to a market
clearing level. Moreover, as that occurs, pipelines with

high-priced gas under contract will be forced to renegotiate
those contracts. The orders correctly and fairly respond
to the court's opinion that the SMP and blanket certificate
transportation programs were anticompetitive because they
fostered monopoly pricing. Since the orders encourage competi-
tive and discourage both discrimination and monopoly
pricing, pipelines have no legitimate reason to refuse to
participate in the Order No. 436 program.

The Day After

Having concluded that pipelines have no legitimate reason
for refusing to participate in a transportation program
conditioned on nondiscriminatory access, the issue now
remains whether the orders will, in fact, be utilized by the pipelines so
as to achieve the goals identified by the court and the
commission remains unresolved. There have been numerous
attempts to subvert or stay the rule, or to dispose of it
entirely.

Following promulgation of Order No. 436, various "emergen-
"petitions for stay of the order were filed with the
court by pipeline companies, alleging that the final rule
"radically changed" the manner in which the commission regul-
lated natural gas transportation, unlawfully imposed upon
the pipelines regulation of a type forbidden by Congress
(that is, mandatory contract carriage), and unlawfully
abrogated contracts.31 The court, by order dated December 31,
1985, denied each of the motions because they did not meet
the requirements of "probability of success on the merits/
likelihood of irreparable injury" necessary for extraordinary
relief. The court thus sent a clear signal that the commission
was proceeding in a manner at least somewhat consistent with
the mandates of MPC I, MPC II, and MPC III. The court did
not preclude normal appeal procedures by this ruling, and
currently about 50 parties, including MPC, are seeking judicial
review of the orders.

The assault on the orders was also carried to the commis-
sion through numerous requests for rehearing and clarification.
The commission has granted some of these requests, but, as
discussed above, the basic thrust of the commission's order
on rehearing is that it remains committed to the policy of
nondiscriminatory access enunciated in Order No. 436.32

Pipelines also attempted to render Order No. 436 a nullity
by refusing to apply for the blanket certificate conditioned
on nondiscriminatory access. At first, only the Columbia
Gas Transmission Corporation accepted such a certificate.
However, this posture is weakening. At the time this paper
was submitted, several other major pipelines had accepted
the nondiscriminatory access provisions, and rumors were
circulating that more would follow.

Another pipeline tactic for avoiding the effect of Order
No. 436 is known as the Section 7(c) "end run." The order


permits the filing of conventional Section 7(c) applications. Section 7 of the Act provides that the commission may issue a certificate authorizing, among other things, the transportation of natural gas, subject to a finding that the transportation is in the public interest and necessity. The certificate may be issued only after due notice and an opportunity for a hearing. Pipelines have utilized this provision to request authority to transport gas on behalf of individual end-users, even though the pipeline has refused to accept a non-discriminatory certificate conditioned on non-discriminatory access.

These requests do nothing more than seek the continuation of the blanket certificate program, terminated by court order as of October 31, 1985. In other words, another attempt to accept a blanket certificate conditioned on non-discriminatory access are attempting to conduct business as usual under the guise of Section 7(c) applications. However, it is clear that the commission was aware of the potential for a loophole which would continue discriminatory, anticompetitive transportation. Indeed, in dealing with a protest raised against one of the early Section 7(c) applications, the commission acknowledged that while requests for conventional Section 7(c) certificates could be filed, Order No. 436 and its underlying rationale would require the commission to assure that it would not be permitting undue discrimination to be perpetrated or perpetuated by individual consideration of the separate certificate applications.

The industry has also attempted to block Order No. 436 through legislative efforts. There were attempts made in Congress to prevent implementation of Order No. 436 both prior to and after promulgation of the rule. These attempts also claim that their contracts have been unlawfully abrogated by the conversion option. Again, this argument is simply unfounded. Firm customers have no obligation to accept delivery of or to pay for any gas with respect to contract demand (CD) amounts. That is, firm customers are not obligated to purchase even one cubic foot of gas from a pipeline's system supply or to pay any amount for the cost of gas not actually purchased. Firm customer's only obligation -- both before and after Order No. 436 -- is to convert and pay the conversion rate for CD amounts, whether or not it buys any gas.

Thus, the contractual obligation of firm customers of pipeline system supply is to pay for transmission capacity only. This has been preserved for such users. Orders No. 436 does not affect this obligation. The only change brought about by the orders is that a portion of the customer's CD may be used to transport gas purchased from sources other than the pipeline system supply. The customer still uses the pipe to transport the same CD amount of gas, and its obligation to pay the fixed costs associated with this capacity remains unchanged.
Moreover, even if a firm customer chooses to reduce, without converting, its CD, the fixed costs will most likely be recovered by the pipeline. If one firm customer reduces its CD capacity, that capacity may be sold to others, and fixed costs will be recovered. And in the event this capacity is not sold (unlikely if current market conditions are any indication), the pipeline still has the ability to file for new rates so that its fixed costs will be recovered. While the spreading of fixed costs over a smaller customer base may not be the rates for transactors victimized by increases in gas prices caused by third parties. Rather, they are both the responsible contracting parties and direct beneficiaries of the soaring prices. Indeed, state officials complained to the FERC beginning in 1982, that pipelines were purchasing gas at excessive prices which justified the denial of pass-through of those costs in rates. In Columbia Gas Transmission Corp., 26 F.E.R.C. ¶61,034 (1984) petition for review pending sub nom. Associated Gas Distributors v. FERC, Case Nos. 84-1100 et al. (D.C. Cir., filed March 16, 1984), the commission found that a pipeline engaged in purchasing practices which were unjust and unreasonable. The pipeline was found to have disregarded potential competition from No. 6 fuel oil and to have acquired gas without regard to the effect of either the purchase price or alternative fuels competition on its market.


7. Ibid., Paragraph J.

making in March and May 1981. In the first, the FERC proposed rules which it accurately described as important but relatively noncontroversial changes to streamline the commission's procedures governing the processing of applications by pipeline companies for routine activities which were typically uncontested and mechanically approved. Sales and Transportation By Interstate Pipelines And Distributors, Docket No. RM 81-29, "Notice of Proposed Rulemaking," issued March 10, 1981 (Phase I). The Phase II Notice, issued April 27, 1981, expanded "blanket certificate" transactions to include sales for resale to other interstate pipelines and eliminate the volumetric and end-use restrictions for transportation to certain high priority end-users. The second notice proposed procedures for a certification of sales from pipelines to other pipelines; this notice also proposed simplifying restrictions on transportation of gas to high priority end-users. Interstate Pipeline Blanket Certificates For Routine Transmissions, Docket No. RM 81-17, "Notice of Proposed Rulemaking," issued May 10, 1981. These proposed rules would have permitted the issuance of "blanket certificates" authorizing these routine activities on a generic basis. Neither notice proposed authorizing pipelines to transport gas released from its system supply to customers who had historically been considered low priority.

9. See, for example, Atlantic Refining Co. v. Public Service Commission, 360 U.S. 378 (1960); and Northern Natural Gas Co. v. FPC, 339 F.2d 953 (D.C. Cir. 1968).

10. See, for example, State of North Carolina v. FERC, 584 F.2d 1003 (D.C. Cir. 1978).


12. For example, the commission recently found that the Columbia Gas Transmission Corporation has engaged in imprudent and reckless purchasing practices. Columbia "virtually ignored" the effect of competition from alternate fuels (particularly No. 6 fuel oil). Moreover, Columbia acquired gas without regard to the effect on its market of the purchase price and alternative fuel competition. The consequence was that Columbia's gas prices exceeded market clearing levels, resulting in loss of load. While the commission found that these practices did not have an adverse effect on Columbia's customers for the period March 1981 to February 1982, the commission is currently conducting proceedings to determine the extent to which Columbia's customers have been harmed in later periods. Re: Columbia Gas Transmission Corp., Docket Nos. TA 81-1-21-001 et al., 26 F.E.R.C. 961,034, Opinion No. 204 (1984).


15. Maryland People's Counsel v. FERC, 768 F.2d 450 (D.C. Cir. 1985) (MPC III).

16. The court rejected two additional rationales offered by the FERC in support of the SMP program. First, in the "other docket's" rationale the FERC stated that MPC's concerns would be fully considered in subsequent proceedings regarding Columbia's SMP. The court noted that at the time of oral argument, one year later, no such order had been rendered. The court stated that the FERC's "Fabian" approach was unacceptable, and deferral of the issue was not proper since MPC's objection went to the heart of the public interest determination, which is properly made in a Section 7 proceeding. Second, the court held that the "experiment" rationale advanced by the FERC was arbitrary. The court stated it was not prepared to say that for the moment the experiment was "carefully circumscribed" to help those who did not need the commission's protection, while hurting those who did.

17. 761 F.2d at 779.


19. 1. Section 284.8(b) (firm service)

Non-discriminatory access. An interstate pipeline or intrastate pipeline that offers transportation service on a firm basis under Subparts B, C, G, or H must provide such service without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural
gas to be transported, customer classification, or undue discrimination or preference of any kind.

2. Section 284.9(b) (interruptible service)

Non-discriminatory access. An interstate or intrastate pipeline that offers interruptible service under Subparts B, C, D, or H must provide such service without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the category, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind.

3. Section 284.221(c) (subjecting blanket certificates to these conditions). Any blanket certificate under this subpart is subject to the conditions of Subpart A of this part.

20. The recovery of associated take-or-pay costs may not be included in any such reservation charge.

21. A firm customer may not elect to convert even 25 percent of the level of its firm sales entitlements to firm transportation before the twelve-month period beginning February 1, 1986. This election may not be effective until 60 days from the proposed conversion Section 284.10(d). Similarly, a customer wishing to reduce its firm purchase obligations cannot give notice of this reduction before the twelve-month period beginning February 1, 1986, and this option cannot be effective for a period less than 180 days before the proposed reduction. Section 284.10(c).

22. As discussed below, this period has been extended to five years.

23. As a related issue, the regulations are deficient since they do not provide that the authority to avoid abandonment proceedings p. 3, at 82. FERC does not question that it has such authority. See Tennessee Gas Pipeline Co. v. FERC, 689 F.2d 212, 214-15 (D.C. Cir. 1982); Transcontinental Gas Pipe Line Corp. v. FERC, 585 F.2d 186, 190 (5th Cir. 1979) (invoking "the well-established principle that generally the Commission has extremely broad authority to condition certifi-


31. Motions were filed by the Natural Gas Pipeline Company of America (No. 85-1699), the Interstate Natural Gas Association of America (No. 85-1713), and Entex, Inc. (85-1721). A similar action was commenced in the Fifth Circuit by the Texas Eastern Transmission Corporation. The Fifth Circuit, like the D.C. Circuit, denied the motion for partial stay.

32. United Distribution Companies and Southwest Gas Corporation petitioned the commission for a stay of the order. The commission in an order dated November 22, 1985, denied these motions, stating it was not persuaded that staying the effectiveness of Order No. 436 was in the public interest. The commission found the petitioners had not demonstrated that implementation of the order would cause imminent irreparable harm within the natural gas industry.


34. 50 Fed. Reg. 42,462.

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I do not intend to explain the details of Order 436 or what it will do. Instead, I will try to describe the philosophy and the regulatory atmosphere preceding and surrounding that rulemaking process. In my view, this is the best way to gain insights into the nature of pipeline regulation after Order 436.

In 1954, the Phillips decision created an unmanageable regulatory burden for the FPC. As a consequence, wellhead price ceilings were frozen during a period of rising production costs. With gas price ceilings below market levels, the FPC had no choice but to substitute administrative fiat for market forces to equilibrate supply and demand. Because gas prices were shielded from economic reality, it became necessary to ration and to establish and administer curtailment priorities; to promote the development of nonconventional supplies such as LNG; to constrain artificially those uses of gas that its distorted price made attractive; and even to tilt rate designs. Having foreclosed any material reliance on market forces to drive adjustments, the FPC (and subsequently the FERC) was compelled to expand its control of and involvement in day-to-day operations of the industry. At best, regulators could seek to bring about by rule those results that would have obtained in the market had gas prices not been distorted in the first place. In the event, things were much worse.

As phased deregulation under the NGPA moved wellhead prices toward market levels, and as the city-gate and burner-
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Charles E. Teclaw

Tip markets became more competitive, it was increasingly necessary to modify the historic regulatory philosophy with its emphasis on insulation of decision makers from market forces and economic reality.

For more than a decade, this industry has been in turmoil. Even with the implementation of Orders 380 and 436, it continues to be in turmoil. The "problem" has been attributed to pre-NPGA price ceilings, or to deregulation under the NPGA, to poor contract decisions involving take-or-pay, to unfair competition, and to a number of other causes. In the words of the report, "the distortions of regulatory intrusion on market forces." As described in Order 436, natural gas is now being traded largely as a commodity, in markets that are largely competitive at the wellhead and the burner-tip. The regulatory philosophy that led to Orders 380 and 436 takes explicit recognition of market forces, market structure, and competition. Such recognition is premised on the fact that market forces are inevitable. Government may impose an outcome, such as a particular price, which differs materially from the outcome that would have obtained under unimpeded market forces. But if it does, a wave of distortions will follow that will reduce further intervention or further distortions. Setting a price administratively either above or below the market price is likely to create a shortage or a surplus for which further administrative actions will be sought.

Administrative solutions should be considered only when it is clear that satisfactory market solutions are not available. Regulators should avoid imposing their preferences on industry participants, instead recognizing that they have their own interests and preferences far better than regulators. Regulatory actions should increase rather than limit the choices and opportunities available to these industry participants.

Orders 380 and 436 both reflect this recognition of the importance of flexibility and voluntary decision making. Both orders were designed to increase choices and to foster voluntary transactions as ever-preferable to those which were compulsory. With regard to Order 436, for example, the commission must deal with at least two major questions. First, and most obvious, is the question of block billing. If followed to its logical conclusions, this may lead to...
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a re-examination of the role and function of PGAs and to the larger issues of gas pricing generally and pipeline sales rates. These issues are now being examined in part in the continuing consideration of the block billing proposal.

In particular, there is the question of how to deal with residual pipeline market power where competitive forces cannot function effectively. This manifests itself primarily when pipelines do not provide nondiscriminatory access to transportation. How much such regulation should be by market forces is a matter of serious concern. The most immediate tasks will be to establish criteria for assuring that individual Section 7(c) certificates for transportation comport with the undue discrimination requirements of the FPA and to establish the interstate return trade-off for pipelines that either accept or reject accountability.

The resolution of these issues can be accomplished under the regulatory principles any way, but the matter of accountability. Economic law is equally invariable whether applied to gas sales or to gas transportation, or whether applied to blanket or to individual transactions. Regulation through market forces wherever they function effectively will always be preferable to regulation by fiat or shadow management. A process that affords opportunities for market adjustments will still be preferable to administratively imposed outcomes. And the principles of accountability and the importance of flexibility and voluntary choice are as applicable to providing sales as they are to providing transportation.

In Order 436 the commission has explicitly applied these principles to pipelines that choose to transport gas on a primary transportation basis. These the results of market discipline in the process that led to Order 380 and in Order 436 and the traditional rate structures that continue to pertain to other areas of the gas business should not be viewed as a gap in the applicability of philosophy or logic to what is, but the continued need to continue to insulate pipelines from market forces and from the consequences of their business decisions are increasingly difficult to justify under the general trend of regulatory philosophy that led first to Order 380 and now to Order 436.

PGAs, for example, were intended in large measure to make pipelines indifferent to producer rate increases during the area rate proceedings by assuring rapid pass through of all gas costs, facilitated by the use of continuing surcharges and credits. PGAs still function to that extent today in a fairly effective manner, except where the pressures of competition are being felt.

The very nature and thrust of the PGAs thus clearly runs counter to the principles embodied in Order 436, which stress accountability and adjustment to current market pricing. A pipeline competing in the world that begot Order 436 must be very sensitive to producer prices, to its own costs, and to burner-tip prices. The commission can certainly establish mechanisms that allow cost pass-through, but it cannot require or guarantee that the market will be willing to pay that price if the market finds the price to be inappropriate.

There are alternatives to the PGA system that better achieve regulation through market forces and better foster accountability. The most extreme form this alternative might take is the use of volumetric posted prices for gas, which could be downwardly flexible. The essential service rate should be regulated to avoid involuntary risk shifting. Alternative risk sharing arrangements might be permitted freely, as long as customers have access to the basic regulated service.

Assuming that commodity rates can be established on some basis that is consistent with market-based regulation, the question still remains whether to permit demand charges, which are revenue guarantees, and, if so, the appropriate design of demand charges for pipeline sales rates. This one area is inextricably linked to determining the appropriate balance of risk and reward in the absence of market discipline.

If the pipeline making sales is also a transporter, the matter of the appropriate level of demand charge revenue guarantees is not important, since customers have the flexibility to opt away from sales, thus avoiding inordinate demand charges. If the pipeline is a merchant, proper resolution of the matters is far more critical.

This leads to the next major set of issues, encompassed by this question: How should the commission regulate pipelines that choose not to be regulated by market forces? In Order 436 the commission noted that the role of regulation was to manage the results of market discipline in order to protect the market and to foster conditions conducive to the development of market forces whenever possible.

In my view, regulation over the years has strayed from these goals; in the present environment, regulation is getting back to these basic industry participants, like regulators, cannot defy economic law. In the long run, efforts to escape market forces will fail, particularly if regulators refuse to prolong the process through protective regulation. Industry participants that seek to avoid regulation by market forces are outlawed and to the commission lacks authority to exempt them. Regulators are bound to protect consumers in the absence of effective market forces; regulators not have an obligation to protect companies seeking a continued and largely artificial monopoly from the effective operation of such market forces. It does not serve the public interest to build an intricate web of regulation around tailored Section 7(c) certificatesspecialty targeted discount sales, and the like.

In contrast, stripping away such trappings through rate design premised on accountability and through regulations approximating the results of unimpeded market forces will provide the
benefits of competition and the voluntary choice of options to natural gas customers and suppliers alike.

THE EFFECT OF THE
FERC RULEMAKING ON NATURAL GAS

Charles R. Eberst, Jr.

Since the issuance of Order 436 on October 9, 1985, the pipeline industry has shown a general reluctance to accept the nondiscriminatory open access provisions provided under the final rule. While the pipelines' actions may have come as a shock to the Federal Energy Regulatory Commission, Order 436 creates a new industry structure utilizing the facilities of the interstate pipelines, but it neglects to give interstate pipelines the tools to deal with the problems created in the transition as this drastic restructuring of the industry takes place. It has reshaped pipeline-purchaser relationships without recognizing the corresponding need to modify pipeline-producer relations.

The intent of the Notice of Proposed Rulemaking (NOPR) on May 31, 1985, was to increase competition among gas pipelines and thereby reduce gas prices by allowing pipelines voluntarily to open up their systems and offer nondiscriminatory transportation. The original proposal was a four-part interrelated package encompassing a transportation policy, take-or-pay, block billing, and an optional certificate procedure. However, upon issuance of Order 436, for unknown reasons or political pressures, the commission only adopted the transportation policy and optional certificate procedure. Take-or-pay was dropped from the package entirely, and block billing was deferred to another proceeding.

These modifications to the original proposal leave pipelines in an untenable situation. At the outset, it is important to emphasize that Order No. 436 is not. It is not a program
to make it easier to provide transportation. It is not deregulation; it is increased pipeline regulation, especially of operations. It is not an even-handed resolution of the problems of the gas industry. It is not an equitable transition to a different industry environment. It is not a complete package at present, as it fails to resolve key issues.

Similarly, I would emphasize what the block billing proposal does not do. It does not put all market participants on a level footing. Rather, pipelines are at a competitive disadvantage due to existing supply commitments and more stringent regulatory restrictions on pricing and marketing gas. It does not give producers any incentive to allocate high cost, high take contracts. It does not properly transmit market signals. It does not reflect consistent treatment of contract sanctity. The sanctity of producer-pipeline contracts is honored, while pipeline-distributor contracts are abrogated.

I will discuss these specific problems with Order 436, particularly the take-or-pay issues and the current block billing proposal, and will offer some solutions. I will also examine the options available to pipelines under the new rulemaking and the implications for pipelines' customers.

**Order 436**

For decades, pipelines have accepted a firm service obligation to their customers. To maintain the supply necessary to meet that obligation, pipelines have entered into firm, long-term contracts with producers. However, spot market gas is currently available to a pipeline's customers at prices well below the regulated pipeline rates that the spot market accounts for approximately 15-20 percent of total gas sales. Morever, purchases of such supplies are sharply on the upswing. The suppliers of this spot gas, however, have no firm service obligation, no necessity to sell a supply, and they deliver gas "as available." By contrast, a pipeline's customers expect it to stand ready to meet their needs on a few hours' notice if spot sources are interrupted. A major distribution company in the Chicago area said exactly that, as reported in Inside FERC's Gas Market Report for November 1, 1985. In October, they were buying 75,000 to 100,000 Mcf/day of spot gas from about seven suppliers. According to a company official: "As winter goes on, we fully expect that we wouldn't get the quantities we're getting now, but we're counting on some deliveries in the winter. We'll fall back on the pipeline suppliers for the full contract volume on the days we have to." It is very difficult for a pipeline to negotiate for supplies to meet peak needs only. Producers want purchasers who take gas throughout the year, not just on peak days. Thus, the increasing use of pipelines as a peaking service aggravates their contract problems.

In light of these conditions, there are four key problems with Order No. 436.

**Supply Responsibility**

Order No. 436 places the entire responsibility for existing supply commitments on pipelines. This is neither fair nor appropriate. A pipeline's customers have played an integral part in developing those supplies. For example, much of Natural Gas Pipeline's current supply was developed through the FERC approved advance payments program during the 1970s. Of the total program advances of about $555 million, Natural's customers directly funded approximately $116 million. These advances resulted in about 1.8 Tcf of reserves, 50 percent of it NGPA $102 gas selling above $4.00 per Mcf. The average cost of these reserves is about $2.80 per Mcf today. In fact, of the 1.8 Tcf, 450 Bcf resulted directly from a $20 million advance from Natural's customers to a single producer. Under the proposed block billing procedure, if these customers are to benefit from low cost Block 1 gas, which they did not fund, then they should share pro rata in the higher cost Block 2 gas they funded and encouraged Natural to obtain. The commission's proposed block billing procedure does not recognize this.

Pipeline supplies were procured based on customer needs as projected by them to pipelines annually. Pipelines did not get in this situation all by themselves. Where pipelines are today is a result of decisions by producers and distributors as well as pipelines. While changes are necessary, producers should not be afforded open access or distributors should not walk away from their contractual obligations to pipelines, with pipelines. Some resolution should be provided through a sharing by all industry segments of the problem of high cost gas contracts and take-or-pay.

**Take-or-Pay**

In Order No. 436, the commission offers no new guidance or solutions on take-or-pay obligation, despite the implications of increased transportation for aggravating this problem.

The industry has been heavily regulated and structured to provide an assurance of reliable service. The spot market is a relatively new phenomenon. Most pipelines are well aware of the need to embrace new goals, including greater price competition, as evidenced by the numerous special marketing programs that have been in existence and the increase in transportation arrangements over the last few years. However, there must be a reasonable transition which addresses the contract issues arising out of the preexisting regulatory scheme, contractual relationships, and industry structure.
The impact of Order No. 436 can be illustrated by a few statistics relating to Natural's pipeline system. Natural's total equity as of September 30, 1965, was $589 million. Regulated earnings for the twelve months ended September 30, 1965, were $84.5 million. If Natural opens its system under Order No. 436, Natural estimates it will incur take-or-pay liability of between $600 million and $1 billion for fiscal 1966. Producers may tell you not to worry about liability of this magnitude, but they are not so flippant when it comes to negotiations with pipelines. When producers are serious that take-or-pay is not a problem, they should be willing to waive take-or-pay in return for open access and the greater marketing opportunities which result. Even if Natural were able to impose contractual liability at 10-15% on the dollar, such payments would still merely erase the jurisdictional earnings. And that would only be a temporary solution. The same problems would arise in 1967, 1968, and so on. Buying out Natural's total obligation on all reserves of high priced gas, even at 10% on the dollar, would erode Natural's equity. Clearly, this is a problem which cannot be ignored and which requires a solution equitable for all parties.

One solution is for producers to waive take-or-pay in return for open access to the pipeline's system and the greater marketing opportunities which would result. A second solution is to permit pipelines to cut back taxes from producers to the extent of transported volumes. A third solution is to permit expedited abandonment of high cost, unmarketable gas supplies combined with waiver of contract rights related to such supplies. A fourth solution would be to permit selection of high cost and low cost contracts if both are held by the same producer.

Equality for Sellers

Under the NGA, pipelines cannot change their prices, alter margins, or seek new markets without specific regulatory approval entailing lengthy delay even in response to new sellers who are taking away their markets. By contrast, other shippers (other than interstate shippers) can change prices daily, discount selectively, and pick and choose markets. Spot sellers, unlike interstate pipelines, need no facilities, have no firm service obligations, and thus need not maintain a firm supply and incur the attendant costs. If a workable competitive gas industry is to be created, pipelines must have equivalent rights with other competitors to price gas, offer discounts, and market gas. Pipelines should be free to purchase spot gas and sell it separately from system supply to any consumer. Order No. 436 does not address these concerns but merely expands the competitive advantages of other sellers vis-a-vis inter-

state pipelines. It is not remotely close to a viable long-term industry structure.

Operational Control

Pipelines must retain the ability to control their own operations. Under Order No. 436, pipelines must essentially serve everyone requesting service. This is a naive and simplistic approach. The example of the impracticality of these rules is the "first come, first served" rule for access to pipeline capacity. If a shipper wishes to use and pay for best efforts transportation on 10 miles of a 1200-mile system, there is no basis for refusing access if capacity is available. Now, if a 800-mile haul materializes a week later, it would promote gross inefficiency to "bottleneck" the pipeline by precluding that long haul in favor of the 10-mile haul merely because the short haul was earlier in line. There are many examples of the operational impracticalities a pipeline can recite concerning Order 436. The direction of Order No. 436 is more regulation.

Block Billing

The commission's block billing proposal raises many of the same issues as Order No. 436. A pipeline wishing to provide "self-implementing" transportation business must open its system to all comers, without regard to the effect on a pipeline's markets, gas supply, or take-or-pay liability. Under the block pricing structure, pipelines will be prohibited from rolling off lower costs of regulated gas with newer, higher cost supplies. In both instances, however, the commission has failed to deal with the enormous take-or-pay obligation of interstate pipelines which will result; strike any sort of balance of interests between pipelines and either producers or distributors during the transition period; provide any means for pipelines to compete as sellers, on an equal footing, with other market entrants such as producers or brokers; and recognize the need for equivalent treatment of contract sanctity at the pipeline-distributor level and at the pipeline-producer level.

The commission has drastically reshaped pipeline-purchaser relationships without recognizing the corresponding need to modify pipeline-producer relations. As discussed earlier, gas purchase contracts entered into by pipelines during the recent period of severe supply shortages often do not reflect current market conditions. They typically include higher price and take provisions that are currently warranted and do not incorporate "market out" or other market sensitive provisions. Therefore, under the
block pricing proposal as currently structured, pipelines will have significantly greater Block 2 gas than they can market at contract prices. The commission’s response is that pipelines can simply refuse to take any gas which is not marketable in Block 2. From the “ivory tower” perspective of abstract economic theory, the commission’s suggestion may sound sensible. Unfortunately, it has nothing to do with the actual world in which producers and pipelines operate. In the real world, pipelines are constrained by both contractual restrictions and state protective laws which contain provisions requiring pipelines to take at least some minimum quantity of gas or be in breach of the contract. This liability is in addition to take-or-pay payments. Furthermore, state protective laws limit the ability of the pipeline to shut in a high cost producer or field. A pipeline cannot simply refuse to take all Block 2 gas.

The proposed block pricing structure would increase the problem, under the commission’s proposal, by restricting their ability to market Block 2 gas. “Old” lower priced gas would be allocated to certain existing customers and billed separately. Only high cost (but not low cost) gas would be available for pricing purposes with current supplies. Therefore, pipelines would be hard pressed to make NOPR Block 2 gas competitively priced. By contrast, new entrants, who do not have existing purchase commitments, can take advantage of the current low field price of gas. Pipelines would be further handicapped because the new entrants do not have the burden of costs entailed in eliminating or reducing take-or-pay obligations and high cost gas agreements. Pipelines would continue to sell the old, low cost NOPR Block 1 gas, but in serving the remainder of the market: they would be at a competitive disadvantage.

Under the commission’s proposed pricing structure, a pipeline’s leverage to negotiate with producers with respect to Block 2 supplies may be more reduced. Agreement by any individual producer to renegotiate a contract will do little to lower the average NOPR Block 2 price and enhance the marketability of Block 2 gas. Attempts by a pipeline to buy new gas at lower prices will not help. Even if new supplies were bought at market levels under the well price levels under prices prevailing today, such gas would not be marketable because it will be placed in the same block with higher cost supplies. Thus, accurate market signals would not be transmitted.

Despite efforts by the pipelines, some producers have refused to renegotiate contracts whose price and take terms do not reflect the market. It is unrealistic to expect NOPR Block 2 prices to become competitive any time soon under the block pricing structure as proposed.

The following modifications to the commission’s block pricing proposal are imperative if it is to work effectively.
Pipeline Options Under Order 436

Now that I have discussed the effect Order 436 will have on the pipeline industry, I would like to examine the three strategic marketing options that interstate pipelines can select in order to adapt to the competitive environment that the commission is attempting to create. The three are: (1) continue as a full service supplier; (2) emphasize transportation/new markets as traditional firm gas supply service shrinks; or (3) become a pure transporter. It is important to note that these options are not mutually exclusive, and a pipeline may choose different strategies for different markets.

Continue as a Full Service Supplier

The first option a pipeline has is to continue its merchant role, limiting sales and transportation efforts to its traditional market. However, in order to maintain sales in the pipeline's traditional market, the pipeline will have to be the low cost supplier on its Block 1 gas. Block 1 gas and marketing sensitive gas in Block 2 will sell. The pipeline will have difficulty selling Block 2 gas that is not market sensitive.

The pipeline's customers will most likely opt to purchase available spot gas after requesting Block 1 and market sensitive gas rather than pay for high priced gas in Block 2. Pipelines electing to maintain their market share must renegotiate contracts containing nonmarket sensitive gas or release the gas.

Obtaining and marketing the incremental gas required above a pipeline's market sensitive supplies represents a true challenge. For example, in Natural's case, more than half the Block 1 gas is in mixed contracts with higher priced gas. If Block 1 gas is not used, the pipeline will lose market share. To offset increased costs, the pipeline may not be able to sell the gas. The pipeline has to be up to buy the incremental gas with spot market purchase contracts, transport the gas to the market, and purchase or brokered by an affiliate, or transport third party gas.

Even if a pipeline elects only to serve its traditional market, the pipeline's activities will change. The key to success in obtaining the "incremental" piece of the market is the ability to respond quickly to the customer's incremental business. Pipelines must be able to make gas supply and transportation arrangements over the phone in 24 hours. Also, sales representatives must have the ability to close deals with the authority to customize deals within previously set guidelines. Multiple receipt and delivery points will be required in most transportation agreements, and the accounting and legal functions must accommodate them. Furthermore, facilities such as meter stations, taps, and short distance pipelines must be installed and ready for service within 30 days. And, finally, the accounting system must shift from a rate base regulatory system to a cost accounting system if pipelines are profitably to take advantage of their unique ability to offer all or a part of their traditional products and services.

Emphasize Transportation/Develop New Markets

A second option available to pipelines is to expand into new markets under the traditional merchant role. The strategy is basically the same as continuing as a full service supplier except that even more effort would be required to capture the "incremental" gas sales market in other pipelines' traditional market territory. The pipeline would require an aggressive sales force in order to gain access to new markets. In addition, the sales force would have to be supported by staff with expertise to arrange transportation on the pipeline's system and on other pipelines' systems.

The appeal of this strategy is that it would not take a lot of capital investment to attempt to enter new markets. The only cost is the amount of management time devoted to entering new markets and the additional sales representatives required.

Pure Transporter

The third alternative is gradually to abandon the gas supply function and emphasize transportation, storage, and administrative services. If a pipeline determines that the increased risk incurred as a result of acquiring gas supply is offset by increased returns, the pipeline will opt for this strategy. The pipeline must determine whether including gas supply in its portfolio of services increases its ability to transport gas profitably. Gas supply must become a profit center; otherwise it may be advantageous to abandon it.

Pipelines electing to be pure transporters will only be successful if they can maintain low costs and are flexible. Keep in mind that the high capacity level will be a crucial factor. Also, pipelines that can offer extras such as storage, flexible contracts, and national deliveries will have true advantages in keeping the line full. Stringent cost controls will become a way of life for a pure transporting pipeline. When costs are not included in the price of the product, all the "insignificant" costs such as labor and fuel become the largest contributors. The successful pipeline transporters will create value for their services by developing packages targeted to specific markets. The price will be based on time of use and character of service. The transporting pipeline will unbundle costs for various services. Prices...
will need to be downwardly flexible with firm and interruptible rates and also include seasonality factors.

Implications for Customers

The last area I would like to cover briefly is the implications for a pipeline's customers under the NOPR environment. In the past, local distribution companies have enjoyed reliable, reasonably priced gas supply and the flexibility offered by pipelines. In the future, the pipeline's ability to offer this same service will hinge on the customers' purchasing practices and commitments. It will be critical for the pipeline's customers to communicate their anticipated future requirements and honor their purchase commitments. Also, local distribution companies must strengthen their relationships with large end-users since this market is too large to risk losing. In order to remain competitive and secure their markets, LOCs will need to develop innovative remaking techniques and offer transportation services. Pipelines want to continue their relationships with their customers, whether as a traditional merchant, a pure transporter, or a combination merchant and transporter.

Conclusion

Pipelines will have a difficult time evaluating these three marketing options with the extreme uncertainty created by Order 436. A pipeline cannot make an election to become a transporter until the block billing proposal and take-or-pay issues are addressed. As I discussed earlier, a workable competitive gas industry is to be created, pipelines must have equivalent rights with other competitors to price gas, offer discounts, and market gas. Most pipelines are not opposed to the concept of open access; however, a balance must exist between the interests of consumers, distributors, producers, and transporters of natural gas. The rule as it now stands places the majority of the risks squarely on the pipelines. Operational common sense is required if a true competitive environment is to emerge from Order 436.

Relations between pipelines and their customers are undergoing profound changes. These were first driven by competitive forces unleashed by the Natural Gas Policy Act of 1978 (NGPA), new federal regulatory policies, and changes in the oil market which ultimately led to gas-on-gas competition. New regulatory changes, especially Order No. 436, are likely to have an important influence on pipelines' relations with their customers. Relationships in this business, and in any utility business, are complicated by service obligations. These, associated with certificates granted to pipelines or other utilities, often commit pipelines to service above and beyond contractual obligations. For example, a pipeline may not automatically abandon service to a customer when a contract expires, and a distributor may not automatically stop service to customers who are not paying their bills.

I want to explore how pipeline-distributor relationships could evolve in light of the potential conflict of interest that Local Distribution Companies (LOCs) face under Order No. 436. This conflict arises in terms of an LDC facing short-run opportunism versus long-term customer-supplier relations. That is, a distributor could take advantage of the new regulations to buy depressed spot market gas, move it on an interruptible basis, and leave the pipeline with its service obligation to serve as supplier of last resort. Of course, distributors not only are the recipients of service

CUSTOMER RELATIONS IN A COMPETITIVE WORLD: A NEW CHALLENGE FOR PIPELINES

William F. Hederman, Jr.
obligations but also are subject to service obligations for their customers.

**Key Elements of Order No. 436**

Others have discussed the details of the new FERC order, but let me briefly review a few key points. First, it is "voluntary." A pipeline may opt to participate. Second, pipeline customers may unilaterally decrease their contractual obligations to the pipeline on a phased schedule set by the commission. In addition, and more troublesome than the contract reduction provision, is the provision that the open access applies to interruptible as well as to firm transportation. There are other important provisions to this order, but these are the ones important for the points I want to discuss.

In responding to the order, each pipeline faces two alternatives. One is to accept open access as a condition for providing flexible transportation services. The other is to remain a traditionally regulated pipeline, with transportation being arranged under Section 7(c) of the Natural Gas Act (NGA). In the next two sections, I will examine the implications of each of these.

**Pipeline Acceptance of Open Access**

The first point to consider with respect to an open access decision is the broad question of whether the relations with customers will take a constructive or destructive turn. I think that pipeline hesitancy to elect the open access option of Order No. 436 is largely a manifestation of concern about the possible consequences. Let me clarify. A constructive approach will require greater cooperation in the pipeline-distributor relationship. In particular, to the extent an LDC sought to reduce its obligations to a pipeline, an LDC would accept responsibility for arranging adequate supplies and transportation for itself. Likely adjustments when a distributor accepts such responsibility would include the LDC arranging a portfolio of gas supply arrangements (short-term, medium-term, and long-term). And if rates design really improved to reflect costs more accurately, each LDC would reassess the level of firm sales entitlements required from the pipeline. Another possible related development would be the joining together in co-ops or mergers of LDCs to improve bargaining power or to spread risks. A destructive approach by LDCs would, in contrast, involve those companies seeking short-run benefits while leaving pipelines responsible for their traditional obligations. Order No. 436 gives LDCs the opportunity to benefit from low spot market prices through interruptible transportation, but pipelines would retain the obligations associated with firm sales entitlements.

At the same time, do not forget that take-or-pay exposure looms as a serious problem for many pipelines under open access. Latest reports indicate that exposure through 1984 was about $5 billion and that another $3 billion would result in 1985. The block billing proposal, combined with the provisions of Order No. 436, could make these figures seem modest.

Another development that would most certainly follow with open access would be unbundling of services now frequently offered on a single-bill, full-service basis. This would mean new rates for services often purchased as part of system supply sales (such as load balancing and storage). These services, often "invisible" to the customer in the past, may cause some form of "bill shock."

**Remaining a Traditional Wholesaler/Utility**

To date, few pipelines have opted for the open access option, and we need to consider the implications of this decision as well. One main effect could be that transportation consumes all of a pipeline's customers will be limited. Some grandfathered transportation options could extend as late as October 1987. Some Section 7(c) certificated programs could provide new transportation programs, but delays appear likely due to the threat of systematic protests by certain parties.

If a pipeline makes this election, customers will need to replace volumes previously transported by pipelines prior to Order No. 436 with system supplies. In some cases, this may raise prices, and this could cause LDCs to face renewed pressure if industrial users switch from natural gas. This trend, however, the FERC has relieved LDCs of significant minimal bill obligations through Order No. 380. Pipelines electing this alternative face several important problems, including threatened challenges to Section 7(c) applications, possible punitive treatment of traditional utility rate cases by the FERC, as well as take-or-pay problems (which may not be as great as under open access). On the other side of the relationship, distributors are worried about the threat of bypassing their networks, with pipelines serving some customers directly.

**Implications of Block Billing**

In addition to Order No. 436, a fourth policy element is still under consideration by the commission. There is an unusual amount of confusion about what this proposal would do. This is due in large part to contradictory information in the proposed regulations. Whenever the Department of Energy may introduce new considerations.

It is particularly unclear how the block billing proposal would improve market signals given existing contracts and...
state regulations. With respect to existing contracts, the block billing material from the FERC specifically mentions that customers would not be given the right to sequence pipeline deliveries. The proposed rule also explicitly states that it would not sequence take. Clearly, both pipelines and LDCs would be doing everything in their power to take as much low cost gas as possible and to lower their Weighted Average Cost of Gas (WACOG), but what additional pressures or means to do so would arise from this proposal is not clear. The other factor the commission seems to be overlooking is that long-term contracts arose to fill a market need. Part of that need may have been the construction of the pipeline network, but such contracts also mitigated important sources of uncertainty. Care must be taken in how these contracts are adjusted to deal with the major regulatory changes now being implemented.

With respect to state regulation, the theoretical benefits hoped for through block billing could be blocked by regulations at either end of the pipeline. For example, if state regulators in consuming states applied rolled-in pricing, this would eliminate the benefits that federal regulators hope for through block billing. Moreover, state regulation of natural gas withdrawal patterns can also block the signals the FERC wants to create. At least one pipeline has already indicated that it is up against "must take" gas limits and cannot cut takes any further.

Another potential consequence of this proposed billing rule is that pipelines could be thrown into competition with their customers for new load. LDCs may gain an advantage in this competition because they could roll in old cost gas in their offering to new potential customers, while pipelines could only offer Block 2 gas.

Conclusion

In conclusion, transportation was playing an increasingly important role in the natural gas business. The attached transportation statistics and related graph from a recent INGAA report make that quite clear. I think it is safe to say that transportation will play an increasingly important role in the natural gas business. There is a status at the moment, however, and the extent of transportation activity continuing in the immediate aftermath of Order No. 436 is uncertain.

The key for pipelines subject to the ill-advised policies of Order No. 436 will be constructive relations with their customers. Distributor customers now face the challenge of accepting new responsibilities when dropping old obligations. Orders No. 436 and 380 can tempt an LDC to play the spot market, move the natural gas on an interruptible basis, and keep the pipeline as supplier of last resort. Such a short-sighted approach would likely harm everyone associated with interstate natural gas markets. Renegotiation of service agreements between pipelines and their distributor customers is one important element of this necessary cooperation. FERC's recent measures create major questions about how these developments will proceed. Pipelines, their customers, and their regulators need to find a way to restructure customer relations that fairly balances the rewards and risks of the new natural gas marketplace. The commission has not provided a framework to encourage such cooperation. The challenge for pipelines and LDCs is to make the "Leap of Faith" that each side is interested in achieving a fair balance between the risks and rewards the industry now faces.

Notes


3. This schedule was modified by FERC, Order No. 436-A, Docket Nos. RM85-1-000, et al., December 12, 1985.

## Appendix A

### Table A-1. Voluntary Carriage, 1984 and 1985, by Quarter

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Voluntary carriage (tcf)</th>
<th>Sales (tcf)</th>
<th>Total (tcf)</th>
<th>Voluntary carriage share of total (%)</th>
</tr>
</thead>
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<td>1.84</td>
<td>3.75</td>
<td>5.59</td>
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<td>2nd</td>
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<td>4.27</td>
<td>39</td>
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<td>4.16</td>
<td>42</td>
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<tr>
<td>4th</td>
<td>1.52</td>
<td>3.01</td>
<td>4.53</td>
<td>34</td>
</tr>
<tr>
<td>1985 1st</td>
<td>1.70R</td>
<td>3.60</td>
<td>5.30</td>
<td>32</td>
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<td>3.62</td>
<td>41</td>
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<td>3rd</td>
<td>1.64</td>
<td>1.85</td>
<td>3.49</td>
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</table>

Source: INGAA survey of members.

Note: Response from pipelines representing 93 percent of interstate purchases and production in 1983 according to the Department of Energy, Energy Information Agency, Statistics of Interstate Natural Gas Pipeline Companies, 1983. R = Revised from previous report.

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**Total Carriage** = **Sales + Total Carriage**

Transportation was classified as “carriage for and under.”

In those cases in which all lines purchased natural gas to generate electricity, the method used was:

\[
\text{Gross Energy} = \frac{\text{Total Carriage} \times \text{MCFM}}{\text{MCFE}}
\]

Source: INGAA survey of members.

**NOTE:** Response from pipelines representing 99 percent of interstate purchases and production in 1984 according to the Department of Energy, Energy Information Agency, Statistics of Interstate Natural Gas Pipeline Companies, 1984. R = Revised from previous report.

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The papers by Thomas Gorak, Charles Teclaw, Charles Eberst, and William Hederman are written by authors representing four of the parties who, within a very short time after the issuance of Order No. 436 on October 9, 1985, had already visited the U.S. Court of Appeals for the District of Columbia Circuit concerning various attempts to obtain immediate relief from the rulemaking order. The intimate experience of these authors with these regulatory proceedings certainly qualifies them to comment on the merits or demerits of the FERC’s action.

Although he is critical of some deficiencies in Order No. 436, Gorak, and his colleagues in the office of the Maryland People’s Counsel, must have experienced satisfaction upon the issuance of Order No. 436 (and Order No. 436A issued December 12, 1985); those orders indicated the FERC had finally embraced the concept of nondiscriminatory transportation of natural gas by interstate pipelines after the agency had resisted the NPC’s efforts to eliminate discrimination through three cases in the D.C. Circuit Court. Naturally, Charles Eberst and William Hederman are less enthusiastic about Order No. 436, and Charles Teclaw, another principal in this evolutionary process, is encouraged that Order No. 436 is a major step in the right direction.

Note: The opinions expressed herein are those of the author and should not be construed as necessarily representative of the opinions of the Iowa Office of Consumer Advocate.
Observers of this country’s energy importation, production, transportation, and consumption might have viewed noncarriers of natural gas as an inevitable development. Those observers who were particularly astute might even have expected that a powerful catalyst in the process of establishing a nondiscriminatory transportation policy would be attempts of the FERC and pipeline industry to abuse the monopoly power of the industry by discriminating against local gas distribution utility companies (LDCs) and their customers. The captive-customer program (CSP) and the blanket certificate program struck down by the D.C. Circuit Court in the MEC cases were, as Gorak says, “a classic abuse of monopoly power.” The court required the FERC to fulfill its duty to promote and protect the public interest by preventing the abuse of monopoly power in the natural gas pipeline industry.

Amid the talk of a competitive national natural gas market, it must be recognized and remembered that the FERC did not, in Order No. 436, eliminate monopoly power in the pipeline industry. When judged by sound economic standards (which cannot be altered by government or industry), pipelines are and will remain monopolies with respect to the transportation of natural gas. Pipelines are obviously the most efficient means of transporting natural gas. Market entry is extremely difficult, costly, and risky because of the large, geographically dispersed capital investment that would be lost upon exit from the market. And pipelines exhibit dramatic economies of scale since capacity is an exponential function of the radius of the pipe. With Order No. 436 the FERC regulates, but does not eliminate, monopoly power in the pipeline industry.

Gorak presents a comprehensive report and analysis of the events leading to the FERC’s issuance of Order No. 436 (including an excellent synopsis of the MEC cases), a brief summary of the FERC’s action on the transportation order, a limited criticism of the order, an update on the situation, and a short response to pipeline industry opposition to the order.

Gorak’s limited criticism of Order No. 436 focuses on the right of LDCs to convert contract demand to firm transportation service. His complaint that LDCs could not take advantage of this right for the 1985-1986 heating season, while valid in principle, tends to overlook the magnitude of the changes in the natural gas industry mandated by Order No. 436 and the uncertainty which both preceded and followed issuance of the order. I suspect that LDCs were not positioned to convert substantial portions of contract demand to firm transportation service during that season, particularly if they shared Gorak’s concerns about pipeline abandonment of transportation service.

Gorak is also critical of the FERC’s phase-in of the right to convert contract demand to firm transportation.

Order No. 436 would have allowed conversion of up to 25 percent of contract demand per year, but in Order No. 436A the FERC lengthened the phase-in period to five years, with conversion limits in the first two years, 20 percent in the third year, and 25 percent in the fourth and fifth years. As Gorak notes, the FERC itself concluded that the conversion order “is an indispensable element of nondiscriminatory access to transportation.” Since the FERC recognized that the conversion order is essential to nondiscriminatory transportation service, its phase-in plan is, by the FERC’s own admission and definition, a perpetuation of discrimination against pipelines’ captive customers. The price of the FERC’s cautious approach to opening pipeline transportation service will be paid by those gas users least able to protect themselves and least able to bear the cost of monopolistic price discrimination -- residential and small commercial firm service customers. Order No. 436 will cause substantial changes in the gas industry, and it would be naive to suppose that the process of implementing nondiscriminatory transportation and pricing could be structured and managed in such a way as to treat all affected persons and entities with perfect equity. Nevertheless, in perverse logic to conclude that because some group of customers will be disadvantaged during the transition to nondiscriminatory transportation, it is appropriate or necessary effectively to exclude that the group to be disadvantaged will be the same group whose vulnerability to monopolistic price discrimination necessitated the establishment and implementation of the regulatory policy in the first place.

Gorak’s other deficiency in Order No. 436 noted by Gorak is the failure to “provide that the authority to avoid abandonment proceedings for self-implementing transportation does not extend to service secured by an LDC through an exercise of its option to convert contract demand.” He suggests that LDCs must afford to relinquish their contract demand in order to have a guarantee that their firm transportation service secured by conversion from contract demand is as reliable as the contract demand. This deficiency may be more serious than the FERC’s phase-in period. An LDC’s firm service to local gas consumers does not become less important (or less worthy of preservation) because all or part of that service is provided with natural gas purchased from a supplier other than the pipeline. An LDC’s firm transportation service obtained by conversion of contract demand should, therefore, be accorded no less protection than is provided the contract demand itself. If LDCs perceive the risk to the continuation of firm transportation service to be substantially greater than the risk to the continuation of firm sales service, they may reject opportunities to obtain lower cost gas supplies, and the elimination of monopolistic price discrimination would be an illusion. To assure achievement of the
objectives of Order No. 436, this deficiency should be remedied.

The pipeline industry view of Order No. 436 as represented by Eberst differs markedly from that of Gorak. Eberst is very critical of the order because, in his view, the FERC did not resolve some of the issues held dear by the pipeline, particularly take-or-pay and high cost gas contracts. In essence, the pipeline industry demands regulatory assurance that its stockholders will not bear any significant share of the costs associated with the pipeline's captive customers, or that it is prohibited from discriminating against its captive customers.

Although the FERC did not determine in Order No. 436 whether to require take-or-pay, as Gorak notes, it did indicate that its previous policy allowing pipeline recovery of prudently incurred take-or-pay costs will remain in effect. Certainly, Gorak is correct in stating the prudent cost standard is reasonable. Industry interest is not to have its supply contracts judged against the prudent cost standard on a case-by-case basis. Rather, it is the pursuit of self-interest.

Eberst suggests producers waive take-or-pay, at least to the extent of transported volumes, in exchange for producers' access to the pipelines' systems. This is not a bad solution. It is less onerous to producers than abrogation of take-or-pay contracts (and there is ample precedent for the abrogation of contracts which are inimical to the public interest) because producers will have the opportunity under Order No. 436 to sell their gas at prices ostensibly established by competitive markets. Equally, if the commission's position that the only cost of this solution to producers is the economic rent they are able to extract under take-or-pay contracts but which they cannot extract from gas consumers in competitive markets.

In an event, the final solution to the take-or-pay problem must not shift costs forward to the pipelines' captive customers. With transportation service available, noncaptive customers can avoid the take-or-pay costs. Shifting those costs to the captive customers is the next logical step, which Order No. 436 is intended to prevent. The same considerations that require governmental imposition of a rule of nondiscrimination for transportation require nondiscrimination in treatment of various quantities of unmetered gas.

Eberst is also critical of the FERC's block billing proposal, which the agency deferred to another proceeding. He argues that take-or-pay on high priced contracts would burden pipelines with substantial quantities of unmeterable gas and composite contracts which effectively require pipelines to take proposed Block 2 gas in order to receive proposed Block 1 gas. Since the effect of take-or-pay on block billing does not dictate a different resolution of the problem than does the effect of take-or-pay on pipeline provision of transportation service, the previous comments on the subject remain applicable. After the Supreme Court's decision in Transcontinental Gas Pipe Line Corp. v. State [of] Mississippi, 106 S.Ct. 709 (1986), striking down a state's attempt to enforce its ratable take rule against a pipeline for the reason that the rule was preempted by the Natural Gas Policy Act, it will be difficult, if not impossible, for producers to employ state prorationing laws to force pipelines to take unmaketable, high cost gas. It may, however, be necessary, as Eberst suggests, for the FERC to contemplate sequencing of purchases to assure producers of proposed Block 1 gas which is covered by composite contracts. Ultimately, the effectiveness of any block billing plan will depend upon state regulatory treatment of gas costs in pipeline designs of LDCs. It is certainly possible for political pressures within individual states to result in effects to (1) preserve "old" low cost gas for traditional firm service customers, particularly for residential space heating and other high priority uses, and (2) preclude underpricing of deregulated gas via rolled-in pricing.

Eberst concludes with a description of three strategies, or options available to pipelines in the new "competitive environment. They essentially cross the spectrum from merchant to transporter, including combinations of the two functions. The choice for a specific pipeline will be difficult and will depend on its particular circumstances. The public interest would best be served if pipelines operated only as transporting utilities. Separation of the transportation function from the merchant function, as well as from the sales and production functions, would allow competition to displace regulation where appropriate and would facilitate more effective regulation where necessary. Implementation of this separation by corporate diversification of the functions' boundaries would diminish, or preferably eliminate, the opportunity for the subsidization of competitive operations by monopoly operations. This sort of restructuring of the gas industry is the next logical step in the evolution toward a "competitive" natural gas market.

Teclaw offers his perspective of the development of Order No. 436, which he recognizes as one major step in the evolution toward comprehensive price regulation to the "competitive" natural gas market. He characterizes the historical "problem" in the natural gas industry for which Order No. 436 is to be a partial solution as a substitution of "administrative flat" for "conventional market forces. While Teclaw's remarks are appropriate (and understandably) general, a better understanding of the niche Order No. 436 occupies in the development of regulation of the natural gas industry
is possible if the "problem" to which he refers is more specifically defined. As the natural gas industry developed in this country, natural economic monopoly, that is, pipeline transportation, was combined with functions which, at least theoretically, could have been governed by market forces but which were accorded artificial monopoly status. That is, the merchant function of pipelines. Wellhead price regulation was, therefore, a necessity. The error of this system eventually led to the passage of the NGPA, another imperfect response which produced the incongruous situation of rising gas prices in the face of falling demand and rising supplies. The "problem" was a failure to identify and distinguish the fundamental economic characteristics of the functional divisions of the natural gas industry and to deal with those functional divisions in accordance with sound economic principles. Order No. 436 is at least an attempt to recognize and appropriately respond to these economic characteristics -- it is an essential control on that part of the industry which possesses natural monopoly power.

Hederman generally echoes the views of Eberst. Thus, my prior comments apply. Obviously, I disagree with Hederman's conclusion that the "policies of Order No. 436 are "ill-advised." I also disagree with his implication that voluntary transportation on the part of interstate pipelines was reasonable and sufficient to assure equitable treatment of gas consumers. Why is pipeline transportation service acceptable to pipelines if provision of the service is controlled exclusively by pipeline management, but "ill-advised" if subjected to a rule of nondiscrimination? The answer is simply that the latter deprives pipelines of the opportunity to exploit their monopoly power at the expense of captive customers.

The basic policy of Order No. 436 is to regulate monopoly power in the natural gas industry in a manner which serves to promote and protect the public interest -- to protect the most vulnerable gas consumers from the extraction of monopoly profits. The adoption of that policy should be welcomed.
PIPELINE MERGERS AND THEIR POTENTIAL EFFECT ON NATURAL GAS MARKETS

Richard P. O'Neill

Mergers can increase the efficiency of markets. If goods and services can be produced at lower costs on a larger scale or in conjunction with other goods and services, the combination of existing firms can lower costs. Nevertheless, the combination of two or more firms buying or selling the same goods or services (a horizontal combination) that results in market power can adversely affect competition by causing wealth transfer and resource misallocation [6]. (Market power is the ability of a company to impose a substantial change on the market, especially in prices, unilaterally.) In general, there are four types of natural gas markets: resource, wellhead, wholesale, and burner-tip. Historically, these have been subject to federal and state regulation ranging from moderate to almost complete. This article examines the structure of natural gas markets, primarily the wellhead and wholesale markets, and the potential competitive effect on these markets of the new relaxed regulations and recent mergers.

Background

Before the Natural Gas Policy Act (NGPA) of 1978, the Federal Energy Regulatory Commission (FERC) and its predecessor, the Federal Power Commission (FPC), followed a cradle-to-grave approach to regulating interstate pipelines. The Natural Gas Act of 1938 (NGA) required the FPC to certificate entry into a market, to assure "just and reasonable" rates for service, and to permit exit from a market. In 1954, the Supreme
Court in Phillips v. Wisconsin decided that the FPC should regulate wellhead prices. In addition, a regulatory wall was constructed around the FPC-regulated interstate markets, precluding many transactions with the intrastate markets not regulated by the FPC.

The NGPA loosened the FERC's control on natural gas markets, mainly by decontrolling most activities related to new gas and requiring that gas be allowed to flow more freely between markets. With the gradual depletion of old gas, the decontrol of new gas will virtually eliminate the commission's jurisdiction over wellhead purchases and, consequently, its jurisdiction over most of the costs in a sale for resale.

In response to requirements of the NGPA and a general philosophy of less regulation, on October 9, 1985 the FERC issued Order 436 to allow faster market entry and exit and to increase competition and rate-setting flexibility. Order 436 reflects the long-term implications of the NGPA, that is, that without full regulation of wellhead sales, the FERC can only effectively regulate interstate transportation of natural gas. Nevertheless, the current structure of interstate natural gas markets was established predicated on a comprehensive regulatory system.

The new flexibility may eliminate much of the implied immunity of natural gas markets from antitrust laws. Under comprehensive regulation, interstate pipelines had relatively little freedom to exercise market power. Indeed a major purpose of such regulation was to prevent use of market power in noncompetitive markets. But in a freer environment, practices leading to antitrust issues may arise. For example, Order 436 explicitly permits what probably will be a large range in transportation rates for the same service. Antitrust suits and threats thereof may be a new source of discipline for natural gas markets in the near future.

Recent Combinations

Many financial analysts consider natural gas pipelines to have very good cash-flows relative to other lines of business. The regulatory system that governed interstate pipelines for decades allowed many companies to realize returns on their rate bases that were both fairly high and consistent. Before the NGPA, however, both intrastate pipelines and producers might have hesitated to enter the interstate pipeline business, for fear that natural gas or their performances might someday become exposed to regulatory scrutiny.

During the 1980s, mergers and acquisitions generally have increased. In the producing sector of the oil and gas industry, combinations, historically, have been common [1], but recent have taken place (Table 1). These combinations are often justified on the basis of undervaluation of reserves or the resource potential of leases.

<table>
<thead>
<tr>
<th>Date</th>
<th>Acquiring company</th>
<th>Acquired company</th>
<th>Cost (billions dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/79</td>
<td>Shell</td>
<td>Beidridge</td>
<td>3.7</td>
</tr>
<tr>
<td>7/79</td>
<td>Mobile</td>
<td>General Crude</td>
<td>0.8</td>
</tr>
<tr>
<td>4/80</td>
<td>Sun</td>
<td>Texas Pacific Oil</td>
<td>2.0</td>
</tr>
<tr>
<td>12/80</td>
<td>Tenneco</td>
<td>Houston Oil and Minerals</td>
<td>1.6</td>
</tr>
<tr>
<td>7/81</td>
<td>DuPont</td>
<td>Conoco</td>
<td>7.0</td>
</tr>
<tr>
<td>11/81</td>
<td>US Steel</td>
<td>Marathon</td>
<td>6.0</td>
</tr>
<tr>
<td>8/82</td>
<td>Occidental Cities Service</td>
<td>4.0</td>
<td></td>
</tr>
</tbody>
</table>
### Table 1 - Continued

<table>
<thead>
<tr>
<th>Date</th>
<th>Acquiring company</th>
<th>Acquired company</th>
<th>Cost (billions dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/84</td>
<td>Texaco</td>
<td>Getty</td>
<td>10.0</td>
</tr>
<tr>
<td>3/84</td>
<td>Chevron</td>
<td>Gulf</td>
<td>13.0</td>
</tr>
<tr>
<td>3/84</td>
<td>Mobil</td>
<td>Superior</td>
<td>5.8</td>
</tr>
<tr>
<td>6/84</td>
<td>Phillips</td>
<td>Amoco</td>
<td>1.6</td>
</tr>
<tr>
<td>10/85</td>
<td>US Steel</td>
<td>Texas Oil and Gas</td>
<td>3.6</td>
</tr>
<tr>
<td>12/85</td>
<td>Occidental</td>
<td>Midcon</td>
<td>3.0</td>
</tr>
</tbody>
</table>

Source: Various news reports.

### Table 2. Mergers and Acquisitions Involving FERC-Regulated Natural Gas Pipelines from 1982 to January 1986

<table>
<thead>
<tr>
<th>Date</th>
<th>Parent company</th>
<th>Acquired pipeline</th>
<th>Cost (billions of dollars)</th>
<th>Acquired markets by state</th>
</tr>
</thead>
<tbody>
<tr>
<td>11/82</td>
<td>Northwest Energy Company</td>
<td>Cities Service Gas (now Northwest Central Pipeline)</td>
<td>.34</td>
<td>CO, KS, MO, NE, OK, TX, WY</td>
</tr>
<tr>
<td>12/82</td>
<td>Burlington Northern</td>
<td>El Paso Natural Gas</td>
<td>1.30</td>
<td>AZ, CO, NM, OK, TX, UT,</td>
</tr>
<tr>
<td>2/83</td>
<td>Goodyear Corp.</td>
<td>Celeron Corp. (includes Mid Louisiana, Louisiana Interstate &amp; Tuscaloosa Pipeline)</td>
<td>.83</td>
<td>LA</td>
</tr>
<tr>
<td>6/84</td>
<td>MidCon In conjunction with Transok &amp; Houston Natural Gas</td>
<td>Conversion of 457 mile crude oil pipeline (formerly Texoma Pipeline Co.)</td>
<td>.13</td>
<td>TX</td>
</tr>
<tr>
<td>1984</td>
<td>Phillips Gas Pipeline</td>
<td>Conversion of 500 mile crude oil pipeline (formerly Seaway System)</td>
<td>TX</td>
<td></td>
</tr>
<tr>
<td>11/84</td>
<td>Houston Natural Gas (Houston Pipe Line)</td>
<td>Transwestern</td>
<td>.39</td>
<td>AZ, KS, NM, OK, TX</td>
</tr>
</tbody>
</table>
Table 2 - Continued

<table>
<thead>
<tr>
<th>Date</th>
<th>Parent company</th>
<th>Acquired pipeline</th>
<th>Cost (billions of dollars)</th>
<th>Acquired markets by state</th>
</tr>
</thead>
<tbody>
<tr>
<td>12/84</td>
<td>Houston Natural Gas</td>
<td>Florida Gas Transmission Co.</td>
<td>.80</td>
<td>AL, FL, LA, NS, TX</td>
</tr>
<tr>
<td>3/85</td>
<td>Coastal Corp. (Colorado Interstate Gas Co.)</td>
<td>American Natural Resources (ANR Pipeline Co., Great Lakes Gas Transmission Co. (50 percent))</td>
<td>2.45</td>
<td>IL, IN, IA, KS, LA, MI, MO, OH, TN, WI, WY</td>
</tr>
<tr>
<td>5/85</td>
<td>InterNorth (Northern Natural Gas)</td>
<td>Houston Natural Gas</td>
<td>2.30</td>
<td>TX, NM</td>
</tr>
<tr>
<td>7/85</td>
<td>Tenneco (Tennessee Gas Pipeline)</td>
<td>Mid-Louisiana Gas, Louisiana Intrastate Gas, Tuscaloosa Pipeline (from Goodyear)</td>
<td>.50</td>
<td>LA</td>
</tr>
<tr>
<td>9/85</td>
<td>MidCon</td>
<td>United Gas Pipe Line</td>
<td>1.14</td>
<td>AL, FL, LA, NS, TX</td>
</tr>
<tr>
<td>12/85</td>
<td>Occidental</td>
<td>MidCon</td>
<td>3.00</td>
<td>AL, AR, CO, FL, IA, IL, KS, LA, MO, NS, NB, NM, OK, TX, WY</td>
</tr>
</tbody>
</table>

Source: Federal Energy Regulatory Commission, Order 436, p. 11-14, and various news reports.

will compete under new regulations and how these new market arrangements will affect prices.

Overview of Competition and Market Structure

Perfect competition is an ideal model, but the necessary conditions to demonstrate that actual markets behave in a manner close to perfect competition are difficult to meet. A theoretical requirement for perfect competition is that no single buyer or seller can influence the price. In general, markets with many firms are presumed competitive, but markets with only a few large competitors, that is, concentrated markets, are considered candidates for further investigation.

In the 1940s and 1950s, the strict structural requirements (and the resulting lack of usefulness for many policy decisions) of the perfect competition model led to a search for a better one [2]. J.M. Clark coined the phrase "workable competition" [3] to describe markets that were less than ideally competitive but enough so not to warrant antitrust intervention. The general idea is that workable competitive markets should not be subjected to government intervention. This concept generated an explosion of articles but has not yet resulted in a clear and concise model. As George Stigler puts it, to determine whether any industry is workably competitive, therefore, simply have a good graduate student write his dissertation on the industry and render a verdict. It is crucial to this test, of course, that no second graduate student be allowed to study the "industry" [4]. In other words, actual markets cannot easily be proved competitive or monopolistic.

Recently, the contestability theory introduced by William Baumol and several colleagues [5; 14] has been presented as a model of competition. Contestable markets are characterized by ease of entry and exit. In a perfectly contestable market, sunk costs (costs of assets with no value for use in other activities) of entry and exit are zero. This condition, like the infinite number of buyers and sellers in perfectly competitive markets, provides an interesting theoretical framework but excludes most actual markets from analysis. The practical consequence of this model is that it can be applied to markets in which entry and exit costs are low or in which sunk costs can be recovered after entry because of institutional rigidities, for example, through fixed tariff provisions for existing firms.

Perhaps more important for practical reasons are the Department of Justice (DOJ) Merger Guidelines issued in June 1984 [6]. These defined "market power" as the power profitably to restrict output, thereby raising prices. Under the "five percent test" set forth in the guidelines, if a single seller (or group of sellers) or buyers in a given market could impose a 5 percent price increase for one year, that entity could be said to have market power.

As a practical screen for market power, the DOJ guidelines established the Hirshman-Herfindahl Index (HHI) as a screen for mergers. The HHI is the sum of the squares of the market shares of either the selling or the buying firms in the market. (DOJ characteristically multiplies the HHI by 10,000. For purposes of this paper, the HHI is left as a number between zero and one, and the DOJ guidelines correspond to an increase in manner close to perfect competition are difficult to meet. A
of 0.01 or a postmerger HHI of 0.18. For a description and examples of how the HHI is calculated, see Appendix B. In its guidelines, the DOJ stated: "If the increase in the HHI exceeds 100 (0.01) and the postmerger HHI substantially exceeds 1,800 (0.18), only in extraordinary cases will such factors establish that the merger is not likely substantially to lessen competition" [6, p.23, brackets added].

The "effective" number of sellers (or buyers), the inverse of the HHI, is a measure that effectively weights the number of sellers by their size (for more details see Appendix B). The DOJ has determined that markets with the concentration of less than 15 percent, five firms of effectively equal size, and candidates for the exercise of market power, and those with more are not. Furthermore, the Department of Justice is likely to challenge the merger of the leading firm in the market with any firm whose market share is at least one percent.

Mergers can also be analyzed vertically [7]. That is, integration of the marketing channels is also subject to examination. The DOJ cites the potential of circumventing regulation, inflating internal price transactions, and tying arrangements as some of the potential problems occurring in vertical mergers. Yet, vertical combinations can create efficiencies by lowering the risk of business transactions between the firms involved [13].

Natural Gas Markets

In general, markets are difficult to define because the products, substitutes, and distribution channels are difficult to specify meaningfully. Natural gas markets are easier to define than most because natural gas is a well-defined product, and distribution channels are defined by pipelines. Because new pipeline construction requires permitting, certification, and construction (which can take more than a year), market entry and exit are not easy. Sunk costs are usually high.

Substitutes for natural gas also are reasonably easy to define. In the residential and commercial market, these are usually home heating (No. 2) oil or electricity. In the industrial or electric utility markets, the substitute fuels include residual fuel (No. 6) oil and coal. Acquiring the capacity to burn substitute fuels costs money; they usually take some price disparity before switching fuels. In addition, the alternative fuel price has often exceeded 105 percent of the gas price for more than one year [7]. Under such circumstances, the natural gas price would need to be able to sustain a 5 percent increase for a year if it faced no competition from other natural gas firms.

There are four basic segments to natural gas markets: resource, wellhead, wholesale, and burner-tip or end-use (retail). Much of the burner-tip market is a pure monopoly, since natural gas distributors are often granted exclusive territories by states and as sole suppliers are heavily regulated. In wholesale markets, distributors and some large end-users purchase gas from pipelines and occasionally purchase (principally in intrastate markets). The first physical exchange of natural gas usually takes place in wellhead markets. Resource markets, markets for resources in the ground, involve the transfer of ownership. This article will not examine the burner-tip (retail) and resource markets in detail, but will focus on the wellhead and wholesale markets, in which questions of competition are most pressing. The analysis, which takes a broader overview of natural gas, is limited to areas in which the data are useful and available.

Wellhead Markets

Wellhead natural gas markets consist of producers (sellers) and, for the most part, pipelines (buyers). Recently, however, producers have been increasing direct sales to downstream buyers, for example, to distributors and large end-users. Producers own or control natural gas reserves, the inventory from which sales are made. The wellhead markets are further complicated by contractual and regulatory claims on the reserves and resources. Most production decisions and pricing are governed by contracts of five to twenty years or more in length. Consequently, market responses are often slow or otherwise limited.

Reserve inventories differ from other inventories in two important ways. First, the rate of production (withdrawal from inventory) depends largely on operational decisions, the geology of the land in which the inventory is stored, and state regulations, rather than just the business judgment of the producer. Second, the quantity in inventory is somewhat speculative (that is, quantities are only estimated, not usually measured) and its value depends on many factors, including the general depletion of the resource [15]. Consequently, the value of reserves relative to the value of the future production stream is determined by estimates of the reserves, the timing of the extraction and sale, interest rates, and expected future prices. In general, these uncertainties make the unit market value of current production about 2.5 to 3.5 times the unit market value of reserves.

The proper definition of a market is a matter of judgment. Geographically, the smallest definition of a wellhead market is usually the field (except for some very large fields). However, because field level data are often unavailable or of doubtful quality, they are not used in this analysis. Next in geographic size is a producing area (for example, southern Texas). For this level of aggregation, data are available. Although some would argue that this definition for a market is too large and, consequently, overstates competition as measured...
by the HHI (because local isolated buyers in smaller areas are aggregated into an apparently more competitive market), the producing area will be used as the market definition for the analysis that follows. This is certainly reasonable for the selling side of the wellhead transaction. A local sales monopoly is of relatively little value when pipelines have no compulsion to buy at all.

For reserve ownership, a form of producer concentration, the producer's (seller's) side of all markets except Alaska has low HHIs and, without additional information to the contrary, appears to be competitive (Table 3). In these markets ownership is characterized by fifteen or more 'effective' owners. In the wellhead markets, there are no available data on all buyers and sellers, but the FERC Purchased Gas Adjustment (PGA) data are available for interstate transactions. Using the PGA data and FERC designated producing areas, very little producer (seller) concentration is observed via the HHI (Table 4). In general, these markets are characterized by ten or more effective sellers. Areas where the HHI is greater than 10 are, in general, small markets or those in which a considerable share of the market is intrastate as measured by the ratio of PGA purchases to all production in an area. (Over half the Texas market is intrastate.) If problems exist in the competitive structure on the seller's side of the wellhead market, they are not apparent at this level of analysis.

Table 3. Concentration of U.S. Natural Gas Reserves Ownership

<table>
<thead>
<tr>
<th>Area</th>
<th>Volume (Tcf)</th>
<th>Percent of area's proved reserves</th>
<th>HHII</th>
<th>Hirschman-Herfindahl index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachian-Illinois</td>
<td>6</td>
<td>16.3</td>
<td>0.029</td>
<td>34</td>
</tr>
<tr>
<td>Other South</td>
<td>45</td>
<td>30.5</td>
<td>0.022</td>
<td>45</td>
</tr>
<tr>
<td>Southern Louisiana</td>
<td>45</td>
<td>61.3</td>
<td>0.043</td>
<td>23</td>
</tr>
<tr>
<td>Texas Gulf Coast</td>
<td>25</td>
<td>55.8</td>
<td>0.053</td>
<td>19</td>
</tr>
<tr>
<td>Permian Basin</td>
<td>18</td>
<td>60.0</td>
<td>0.033</td>
<td>30</td>
</tr>
<tr>
<td>Hugoton-Anadarko</td>
<td>33</td>
<td>37.2</td>
<td>0.023</td>
<td>43</td>
</tr>
<tr>
<td>Rocky Mountain</td>
<td>28</td>
<td>30.8</td>
<td>0.062</td>
<td>16</td>
</tr>
<tr>
<td>California</td>
<td>6</td>
<td>55.0</td>
<td>0.053</td>
<td>19</td>
</tr>
<tr>
<td>Alaska</td>
<td>33</td>
<td>95.6</td>
<td>0.238</td>
<td>4</td>
</tr>
<tr>
<td>Total United States</td>
<td>209</td>
<td>54.3</td>
<td>0.028</td>
<td>36</td>
</tr>
</tbody>
</table>

Analyzed in two stages, first using the corporate ownership before 1982, then examining the market following all mergers as of November 1, 1984. The premerger concentration of buyers (pipelines) is greater in all regions than the concentration of producers, often by a substantial margin. In 11 of 26 areas the HHI falls into the range that would be called into question by the DOJ guidelines (Table 4). Many of these areas are

Table 4. Hirschman-Herfindahl Indices (HHI) for Pipelines

<table>
<thead>
<tr>
<th>Producing area</th>
<th>Interstate pipeline buyer HHI</th>
<th>Interstate pipeline seller HHI</th>
<th>PGA purchase quantity (Bcf)</th>
<th>PGA purchases as fraction of EIA-E23 production</th>
<th>Average PGA price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Appalachian</td>
<td>0.266</td>
<td>0.022</td>
<td>84</td>
<td>0.35</td>
<td>$3.69</td>
</tr>
<tr>
<td>Basin North</td>
<td>0.330</td>
<td>0.056</td>
<td>247</td>
<td>0.36</td>
<td>$2.99</td>
</tr>
<tr>
<td>Appalachian</td>
<td>0.330</td>
<td>0.056</td>
<td>247</td>
<td>0.36</td>
<td>$2.99</td>
</tr>
<tr>
<td>Basin South</td>
<td>0.500</td>
<td>0.071</td>
<td>61</td>
<td>0.26</td>
<td>$2.85</td>
</tr>
<tr>
<td>Arkansas (North)</td>
<td>0.414</td>
<td>0.303</td>
<td>10</td>
<td>0.20</td>
<td>$2.17</td>
</tr>
<tr>
<td>Arkansas (South)</td>
<td>0.362</td>
<td>0.091</td>
<td>70</td>
<td>0.39</td>
<td>$3.20</td>
</tr>
<tr>
<td>Colorado-Julesburg</td>
<td>0.239</td>
<td>0.078</td>
<td>373</td>
<td>0.83</td>
<td>$1.21</td>
</tr>
<tr>
<td>Kansas</td>
<td>0.163</td>
<td>0.019</td>
<td>186</td>
<td>0.51</td>
<td>$2.59</td>
</tr>
<tr>
<td>Louisiana (North)</td>
<td>0.128</td>
<td>0.065</td>
<td>863</td>
<td>0.65</td>
<td>$2.90</td>
</tr>
<tr>
<td>Louisiana (South)</td>
<td>0.096</td>
<td>0.052</td>
<td>3,656</td>
<td>0.92</td>
<td>$2.54</td>
</tr>
<tr>
<td>Offshore</td>
<td>0.260</td>
<td>0.029</td>
<td>167</td>
<td>0.64</td>
<td>$4.28</td>
</tr>
<tr>
<td>Mississippi</td>
<td>0.568</td>
<td>0.054</td>
<td>42</td>
<td>0.16</td>
<td>$1.02</td>
</tr>
<tr>
<td>Montana</td>
<td>0.168</td>
<td>0.063</td>
<td>77</td>
<td>0.33</td>
<td>$3.33</td>
</tr>
<tr>
<td>Dakota</td>
<td>0.745</td>
<td>0.074</td>
<td>615</td>
<td>0.24</td>
<td>$2.42</td>
</tr>
<tr>
<td>New Mexico</td>
<td>0.394</td>
<td>0.047</td>
<td>619</td>
<td>0.24</td>
<td>$2.34</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>0.200</td>
<td>0.018</td>
<td>560</td>
<td>0.39</td>
<td>$3.39</td>
</tr>
<tr>
<td>Andarko</td>
<td>0.157</td>
<td>0.021</td>
<td>271</td>
<td>0.17</td>
<td>$1.76</td>
</tr>
<tr>
<td>Panhandle</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4. Continued

Richard P. O'Neill
<table>
<thead>
<tr>
<th>Producing area</th>
<th>Interstate pipeline (buyer) HHI</th>
<th>Interstate pipeline (seller) HHI</th>
<th>PGA purchase quantity (Bcf)</th>
<th>PGA purchases as fraction of EIA-23 production</th>
<th>Average PGA price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oklahoma Panhandle</td>
<td>0.157</td>
<td>0.021</td>
<td>271</td>
<td>NA</td>
<td>$1.76</td>
</tr>
<tr>
<td>Oklahoma (Other)</td>
<td>0.323</td>
<td>0.023</td>
<td>111</td>
<td>NA</td>
<td>$3.04</td>
</tr>
<tr>
<td>TRRC</td>
<td>0.145</td>
<td>0.035</td>
<td>95</td>
<td>0.30</td>
<td>$2.66</td>
</tr>
<tr>
<td>District 2</td>
<td>0.153</td>
<td>0.042</td>
<td>84</td>
<td>0.11</td>
<td>$2.37</td>
</tr>
<tr>
<td>District 3</td>
<td>0.159</td>
<td>0.051</td>
<td>371</td>
<td>0.35</td>
<td>$3.12</td>
</tr>
<tr>
<td>District 4</td>
<td>1.000</td>
<td>0.149</td>
<td>3</td>
<td>0.02</td>
<td>$2.94</td>
</tr>
<tr>
<td>District 5</td>
<td>0.210</td>
<td>0.034</td>
<td>162</td>
<td>0.40</td>
<td>$3.24</td>
</tr>
<tr>
<td>District 6</td>
<td>1.000</td>
<td>0.539</td>
<td>40</td>
<td>0.31</td>
<td>$2.68</td>
</tr>
<tr>
<td>District 9</td>
<td>0.138</td>
<td>0.056</td>
<td>411</td>
<td>0.70</td>
<td>$1.90</td>
</tr>
<tr>
<td>District 10</td>
<td>0.173</td>
<td>0.653</td>
<td>792</td>
<td>0.74</td>
<td>$3.09</td>
</tr>
<tr>
<td>TX Federal Offshore</td>
<td>0.217</td>
<td>0.071</td>
<td>399</td>
<td>NA</td>
<td>$3.01</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>7,287</td>
<td>0.66</td>
<td>$2.67</td>
</tr>
</tbody>
</table>

Sources: Federal Energy Regulatory Commission, Purchased Gas Adjustment filings, and Energy Information Administration, Form 23.

Note: NA = Not available. TRRC = Texas Railroad Commission.

relatively small, but they total more than one-third of the gas represented in the PGA. In several areas the same is true for the lower bound on the HHI (PGA HHIx(PGA quantity/EIA-23 quantity)^2). The lower bound assumes that there are an infinite number of small buyers for gas not covered in the PGAs.

This creates a dilemma in using the guidelines for mergers since many HHIs do not meet the criteria set forth in the guidelines before a pipeline merger and therefore cannot meet them after a merger. Nevertheless, the mergers do increase the HHIs considerably in several areas (Table 5). Seven regions (Louisiana North, Montana-Wyoming, New Mexico [four counties], Oklahoma Panhandle, Other, Texas [Railroad Commission Districts 6 and 10]) appear likely to meet both DOJ criteria.

<table>
<thead>
<tr>
<th>Number of buyers before combinations</th>
<th>Number of buyers after combinations</th>
<th>Area PGA purchase quantity (Bcf)</th>
<th>Average PGA price ($/Mcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Louisiana (North)</td>
<td>14</td>
<td>0.163</td>
<td>12</td>
</tr>
<tr>
<td>Louisiana Offshore</td>
<td>18</td>
<td>0.096</td>
<td>13</td>
</tr>
<tr>
<td>Montana-Wyoming</td>
<td>11</td>
<td>0.168</td>
<td>10</td>
</tr>
<tr>
<td>New Mexico (4 counties)</td>
<td>10</td>
<td>0.394</td>
<td>8</td>
</tr>
<tr>
<td>Oklahoma Panhandle</td>
<td>12</td>
<td>0.157</td>
<td>9</td>
</tr>
</tbody>
</table>

Sources: Federal Energy Regulatory Commission, Purchased Gas Adjustment filings.

Wholesale Markets

This study will define a wholesale market by a single purchaser, the distributor. This is reasonable because distributors usually serve geographically defined territories within which there is little or no competition. The current structure of wholesale interstate markets has been heavily influenced by FERC decisions granting certificates over the last 50 years. But if regulations are to be relaxed, then new opportunities for the exercise of market power arise.

In wholesale markets, the confusing issue in analyzing mergers is that few wholesale markets pass the DOJ screen prior to a merger (Table 6) and, therefore cannot pass it after the merger. Although the HHI increases by more than .01 in some markets after a merger, this consideration pales in light of the premerger HHIs. In general, the increase in sales HHIs after mergers is relatively small because the pipelines involved serve different areas. (The supplier's HHIs differ from the wellhead purchaser's HHIs because merged pipelines often purchase in the same markets.)
More than half the wholesale markets have only one supplier, but these markets are small and constitute only 15 percent, by quantity, of the distributor markets (Table 6). Overall, the average effective number of sellers in wholesale markets is less than two. Even in markets with five or more suppliers, the high market shares of the larger sellers make the effective number of competitors fewer than two. Most larger interstate pipelines effectively have only one other sales competitor and more than a 50 percent market share in their average market. Furthermore, it should be emphasized that this analysis is for sales. Since many of the sales are transported over the same physical pipeline systems, the concentration of transportation service would be even higher.

Given this general lack of competitive structure in the wholesale market, mergers may create or enhance market power even without increasing concentration in any given market.

Table 6. Concentration in Wholesale (Distributor) Markets

<table>
<thead>
<tr>
<th>Number of sellers</th>
<th>Number of sellers</th>
<th>Sellers (marketers)</th>
<th>Effective HHI</th>
<th>Bcf</th>
<th>Total Market share</th>
<th>Market share of the second largest seller</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Aver- age weighted volume</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Act- tive volume</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(in largest market)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(in largest market)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(HHI)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(Bcf)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Tcf</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>876</td>
<td>1</td>
<td>1.00</td>
<td>2.1</td>
<td>1.00</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>350</td>
<td>2</td>
<td>0.91</td>
<td>1.3</td>
<td>0.94</td>
<td>0.06</td>
<td></td>
</tr>
<tr>
<td>106</td>
<td>3</td>
<td>0.83</td>
<td>2.2</td>
<td>0.99</td>
<td>0.10</td>
<td></td>
</tr>
<tr>
<td>56</td>
<td>4</td>
<td>0.64</td>
<td>2.5</td>
<td>0.71</td>
<td>0.19</td>
<td></td>
</tr>
<tr>
<td>36</td>
<td>5</td>
<td>0.64</td>
<td>1.9</td>
<td>0.76</td>
<td>0.17</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>6</td>
<td>0.48</td>
<td>1.3</td>
<td>0.61</td>
<td>0.24</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>7</td>
<td>0.51</td>
<td>1.0</td>
<td>0.66</td>
<td>0.18</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>8</td>
<td>0.42</td>
<td>0.6</td>
<td>0.52</td>
<td>0.31</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>9</td>
<td>0.34</td>
<td>0.7</td>
<td>0.49</td>
<td>0.27</td>
<td></td>
</tr>
</tbody>
</table>


* Effective number of sellers = 1/HHI

**The Mergers**

In general, the pipeline combinations that have taken place since 1982 could be classified as strategic development of the hub and spoke configuration. The hub, the Gulf Coast in Texas and Louisiana, is not only where most companies maintain a large corporate presence but also where considerable production, consumption, and transportation capacity is located.

The spokes consist of two types: those extending to predominantly wellhead markets and those extending to predominantly wholesale markets. The most important wellhead market with virtually no consumption is the Gulf of Mexico offshore. Other wellhead markets with limited consumption include the Permian Basin (western Texas), the San Juan Basin (northwestern New Mexico), and the Rocky Mountain Thrust Belt.

Currently, the three largest companies (as measured by 1984 sales) are Midcon (Figure 1), HNG/Internorth (Figure 2), and Tenneco (Figure 3). All are remarkably similar in general configuration. All have a significant presence in the Gulf of Mexico and the Gulf Coast but have few competitors in their wholesale markets. These latter are by several aggregate measures highly concentrated (Table 7). Two other companies resulting from combinations, Coastal (Figure 4) and Williams (Figure 5), maintain hubs in the gas-rich Hugoton/Panhandle area of Texas, Oklahoma, and Kansas and serve highly concen-
treated wholesale markets. With the hub and spoke network configuration these large companies can make purchasing and dispatching decisions that create economies of scale and scope, thereby lowering costs of serving markets.

Table 7. Concentration in Wholesale Markets for Selected Major Interstate Pipeline Companies, 1984

<table>
<thead>
<tr>
<th>Company</th>
<th>Sales (Tcf)</th>
<th>Weighted HHI for sales</th>
<th>Market share for sales</th>
<th>Market share weighted average</th>
<th>HHI for sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>MidCon</td>
<td>1.36</td>
<td>0.61</td>
<td>0.67</td>
<td>0.42</td>
<td></td>
</tr>
<tr>
<td>HNG/Internorth</td>
<td>1.04</td>
<td>0.63</td>
<td>0.57</td>
<td>0.45</td>
<td></td>
</tr>
<tr>
<td>Tenneco</td>
<td>0.92</td>
<td>0.66</td>
<td>0.53</td>
<td>0.44</td>
<td></td>
</tr>
<tr>
<td>Texas Eastern</td>
<td>0.52</td>
<td>0.42</td>
<td>0.35</td>
<td>0.16</td>
<td></td>
</tr>
<tr>
<td>Transco</td>
<td>0.89</td>
<td>0.53</td>
<td>0.60</td>
<td>0.36</td>
<td></td>
</tr>
<tr>
<td>El Paso</td>
<td>0.82</td>
<td>0.44</td>
<td>0.56</td>
<td>0.27</td>
<td></td>
</tr>
<tr>
<td>Coastal</td>
<td>0.87</td>
<td>0.66</td>
<td>0.74</td>
<td>0.54</td>
<td></td>
</tr>
<tr>
<td>Columbia</td>
<td>0.83</td>
<td>0.71</td>
<td>0.77</td>
<td>0.58</td>
<td></td>
</tr>
<tr>
<td>Williams</td>
<td>0.73</td>
<td>0.90</td>
<td>0.91</td>
<td>0.86</td>
<td></td>
</tr>
</tbody>
</table>


HHI in each market is weighted by the total sales in that market. Market share is the share of all markets.
Potential Effect

Perfectly competitive markets are appealing because they are self-disciplined, outcomes yield efficient output levels, and monopoly profits (rents). Markets in which competition is neither perfect nor perfectly contestable have the potential for producing inefficient results and monopoly profits. This potential is increased when sunk costs increase and competitors decrease. Industry representatives have implicitly acknowledged the existence of some market power by conceding that "gas pipelines do not possess excessive market power in either the field or citygate markets" [20]. Increased efficiency and consumer prices are lowered. Economies of scale, better integration of facilities, and lower transportation costs are all cited as arguments for mergers. Another (considerably different) argument in favor of mergers is the "failing firm" defense, in which a merger is permitted because one of the firms is failing.

Interstate pipeline companies have traditionally performed two quite different roles in the overall natural gas industry: They have physically transported gas, and they have acted as sellers for gas. In terms of the possibility for competition, especially under contestability theory, these roles are very different. The business of transporting natural gas is characterized by significant sunk costs. Once the pipe is in the ground, there is virtually no mobility of these assets. In interstate commerce, barriers to entry and exit are added by FERC regulations, the NGA, and state law. Thus, the ability to circumvent these barriers. In any case, the construction of a new pipeline to enter a market is time-consuming as well as expensive, making quick entry almost impossible. Consequently, with the exception of sales taxes and other relatively small public projects, it is hard to argue that the transportation market is contestable. Yet, sales of natural gas require only the establishment of a brokerage. The sunk costs of opening a brokerage can be relatively small, and there are few regulatory barriers to entry or exit that appear to be necessary. As a result, the brokerage of natural gas may qualify as a contestable market. If a transportation option for the buyer does not exist along with pipeline sales for resale, the opportunity to extend market power through tying arrangements exists.

In supply markets, the inability to obtain transportation to central marketing points (for example, the Gulf Coast) at reasonable cost can cause market failures and potential underdevelopment of resources in remote areas or areas with high pipeline concentration. Additional geographic scope in producing areas will place postmerger companies in a better position to take advantage of temporary geographic market imbalance in buying and selling. Independent producer groups in Texas and Oklahoma have requested protection from potential discrimination by MidCon after its recent acquisition by Occidental [17].

On January 22, 1986, the Supreme Court decided that Mississippi's ratable take order was pre-empted (Transcontinental v. Missississippi). Even the dissenting opinion saw little need for ratable takes across reservoirs. One function of ratable take rules is to prevent a pipeline from using its market power against producers. If the decision is interpreted broadly, most state ratable take statutes are no longer operable for interstate commerce. If ratable take orders are no longer enforceable, market power could be exercised by pipelines as "essential facilities" under antitrust law.

In the wholesale markets, concentration measures indicate that the number of sellers is not large. Historically, substitutes for natural gas in end-use markets have fluctuated considerably relative to natural gas. In addition, there are usually nontrivial sunk costs needed to install equipment to burn alternatives, and in some cases an alternative creates environmental concerns. Consequently, high potential for collusive or monopolistic behavior exists. (The DOJ has just announced an investigation into pipeline activities [18].) Furthermore, Order 436 allows for selective discounting with considerably less information to be filed at the FERC concerning these new transactions. These factors lead to the potential use of market power.

Dealing with market structure and mergers from a regulatory viewpoint, one principle is to regulate where competitive outcomes are inhibited and to allow competition where possible. In a very short period of time, a high level of combination activity occurred, more than half the wellhead market was deregulated, the FERC issued Order 436, and the Supreme Court struck down a ratable take rule. The natural gas market is in rapid transition. But because the requisites for efficient outcomes are hard to establish, significant new concerns are replacing old ones. If market power is exercised in the spoke markets served by these companies, the benefits of these new company configurations may never be seen by consumers or producers.
APPENDIX A.

NATURAL GAS COMPANIES AND AFFILIATES

MIDCON

Natural Gas Pipeline Company of America

U-T Offshore (joint ownership with United and Transco)
High Island (in joint ownership with ANR, United, Texas Gas, and Transco)
Stingray (50%; 50% Trunkline).

United Energy Resources

United Gas Pipeline (still pending before FTC)

Texas Gas Offshore
Texas Adventarko
United Alaska Fuels
United Mid-Continent Pipeline
United Offshore Company
United Offshore Transmission Company
High Island
Sea Robin (50%; 50% Southern)
U-T Offshore
Border Pipeline

Alabama Gulf South
Florida Gulf South
Gulf South
Mississippi Gulf South
Texas Gulf South
UTTCO
Coastline Gas
South Gulf Energy Inc.
Texas Industrial Energy Co.
United Texas South Plains, Inc.
Palo Duro Pipeline
South Plains Energy
Titus Co.

Mississippi River Transmission (September 3, 1983)

Midcon Texas Pipeline Corp.
Midcon Louisiana Pipeline Corp.
Midcon Oklahoma Pipeline Corp.
Midcon Mississippi Pipeline Corp.
MCN Acadian Gas Pipeline Corp. (50%)
MCN Tidal Transmission Co.

MCN Bayou Interstate Pipeline Corp. (50%)
MCN Calcasieu Gas Gathering (50%)
MCN La Industrial Gas Supply (50%)
Cajun
MCN Pelican Transmission (50%)
MCN Spindletop Gas Distribution Corporation (50%)
Golden Triangle
MCN West Lake Arthur

COASTAL

ANR (March 14, 1985)

ANR Gathering
Great Lakes Transmission (50%; 50% TransCanada)
High Island (Partial)
Pathfinder (Partial)
ANR Pipeline

Colorado Interstate Gas (January 2, 1973)

Wyoming Interstate Gas

Cody Gas Company

INTERNORTH

Northern Natural Gas Pipeline
Consolidated Gathering Systems
Consolidated Natural Gas Ltd.
Consolidated Pipeline Company
Northern Intrastate Pipeline
West Texas Gas
Houston Natural Gas (May 1985)

Houston Pipeline Company
Intratex Gas Company
Valley Pipelines, Inc.
Llano, Inc.
Panhandle Gas Company
HNG Offshore Company
HPI Transmission
Industrial Natural Gas Company
Oasis Pipeline Company (50%)
HF Gathering Company (50%)

Florida Gas Transmission (December 1984)

Florida Intrastate Pipeline Company

Transwestern (November 1984)
PANHANDLE EASTERN PIPELINE COMPANY

Trunkline Gas Company
Trunkline Offshore Company

Illinois NapGas
Stingray (50%; 50% Natural Gas Pipeline)

WILLIAMS COMPANY

Northwest Energy Corporation (October 1983)

Northwest Central Pipeline Corporation
Northwest Pipeline Corporation

Williams Pipeline Company

TENNECO

Tennessee Gas Pipeline
Midwestern Gas Transmission
East Tennessee Natural Gas
Collins Pipeline Company
Cresol Gas Pipeline
G & T Pipeline Company
LHC Pipeline
Northeastern Gas Transmission
Oasis Pipeline
Seahorse Offshore Transmission
State Gas Pipeline
Tennessee Overthrust Gas Company
Tennessee Gas Transmission
Tennessee Iroquois Gas Company
Tennessee Niagara Gas Company
Tennessee Ozark Gas Company
Tennessee Trailblazer Gas Company
Tennessee Trans-Andarko Gas Company
THC Pipeline Company
Louisiana Industrial Gas Supply
Mid-Louisiana Gas Co. (1985)
Louisiana Intrastate Gas Corp.
Tuscaloosa Pipeline Co.

Northern Border Pipeline Company is owned by the following companies.

InterNorth (22.75%)
The Williams Companies (12.25%)

Panhandle Eastern Corporation (22.75%)
United Gas Pipeline Company (12.25%)
TransCanada Pipelines LTD (30.00%)
APPENDIX B.

Calculation of Hirschman-Herfindahl Index

The Hirschman-Herfindahl Index (HHI) for a market is calculated as follows:

$$HHI = (\text{Market Share of Firm 1})^2 + (\text{Market Share of Firm 2})^2 + \ldots + (\text{Market Share of Firm n})^2$$

where the market share is a number between zero and one.

The HHI is 1.0 for monopolies, and the HHI is near zero for classical competitive markets.

Examples of the HHI calculation:

If there are two firms of equal size in a market, the

$$HHI = (0.5)^2 + (0.5)^2 = 0.5$$

and the effective number of sellers (1/HHI) is two.

For two firms of unequal size,

$$HHI = (0.75)^2 + (0.25)^2 = 0.63$$

and the effective number of sellers is 1.6

For five firms of equal size,

$$HHI = (0.2)^2 + (0.2)^2 + (0.2)^2 + (0.2)^2 + (0.2)^2 = 0.2$$

and the effective number of sellers is five.

For five firms of unequal size,

$$HHI = (0.4)^2 + (0.3)^2 + (0.1)^2 + (0.1)^2 + (0.1)^2 = 0.28$$

and the effective number of sellers is 3.6.

References


MERGERS IN THE NATURAL GAS PIPELINE INDUSTRY:
ENFORCEMENT OF SECTION 7 OF THE CLAYTON ACT BY THE FTC

Marc G. Schildkraut

As one might expect of an industry in transition, the energy industry has been evolving in a number of ways. Oil and gas mergers are one visible sign of this evolution. It is the task of the Federal Trade Commission (FTC) and the Antitrust Division of the Department of Justice to review these mergers for any anticompetitive effects. It is my task to examine a small part of that review process, namely, how the FTC analyzes a merger between natural gas pipeline companies. I should note that when I use "we," I am referring to the staff of the FTC, not the commission itself or any individual commissioner.

I shall begin with the process named after the Hart-Scott-Rodino Antitrust Improvements Act of 1976, which has revolutionized merger review procedures under Section 7 of the Clayton Act. Prior to the 1976 act, the FTC and the Antitrust Division often learned about an acquisition after consummation. Postacquisition litigation was the typical means of enforcing the law, which could be a long, drawn-out, and expensive process, and at the end adequate relief was not always available because we could not always reconstruct a fully effective and viable competitor after a lapse of many years.

With the passage of Hart-Scott-Rodino, the situation changed dramatically. Before two companies may merge, they must notify the commission and Antitrust Division of their

Note: The views presented are the author's and do not necessarily reflect those of the Federal Trade Commission or any individual commissioner.
intended action and wait for 30 days (in most cases), giving the agencies an opportunity to review the acquisition. Through a clearance procedure, the agencies determine which of them will review. The FTC usually handles natural gas pipeline acquisitions because of its greater experience in this area. During the 30-day waiting period, the FTC (or Antitrust Division, if it is the investigating agency) may request additional information and documents from the companies. When such a request is issued, the parties cannot consummate the acquisition until 20 days after providing the material.

The waiting period is shorter if the acquisition is a cash tender offer, which has been true of almost all the major oil and gas mergers. In such cases, the agency must request additional information within 15 days, and once the acquiring company submits the materials it must wait only 10 days before "taking down" the stock of the target company. Typically, one to two weeks elapse before the agencies respond to a request. Thus, in a cash tender offer context, the time available for review is generally about one month.

At any point during the review, the agency can terminate the waiting period if it finds the acquisition is unlikely to have an anticompetitive effect. This is what usually happens, since most mergers are either benign or beneficial. In 1984, requests for additional information were issued for only 5.5 percent of the reported transactions.

If there appears to be a competitive problem, the FTC may follow one of several courses before the waiting period ends. It may seek to enjoin preliminarily the acquisition under Section 13(b) of the Federal Trade Commission Act, which is not a final determination on the antitrust issue but a court injunction if the commission presents fair grounds for a thorough deliberation and determination by the FTC.

If the court grants the injunction, the matter is returned to the commission for administration adjudication, but in many cases this proves unnecessary because the parties often rescind their merger agreement at this point. If the court does not grant a preliminary injunction, the parties are free to consummate the acquisition, but by that time the commission is likely to have issued an administrative complaint, which means the matter returns to the commission for administrative litigation. The objective of any administrative litigation is to determine whether there is a violation of Section 7 of the Clayton Act and whether a divestiture of assets or other remedy is available and appropriate.

On rare occasions, the FTC has forgone the preliminary injunctive remedy and proceeded directly to an administrative litigation. The commission is unlikely to select this course unless there are special circumstances or very good reasons to believe the acquisition would not harm competition in the short run and any long-run harm could be remedied without much difficulty.

If possible, the FTC seeks to avoid either of these steps when it has reason to believe Section 7 has been violated and prefers to negotiate an agreement containing a consent order which spells out whatever relief the FTC considers necessary to remedy the problem. For example, the order might require the merging parties to divest certain assets. When the commission provisionally accepts the order, the parties can proceed to consummate the acquisition. The FTC places the order on the record for public comments, and based on those received and additional staff analysis, the commission can issue the order as final or reject it and take whatever additional actions it deems appropriate.

This brief review of the procedural setting brings us to the substantive analysis of competitive effects, which are of critical importance. Under Section 7, the commission has no authority to challenge mergers just because they are large in physical or monetary terms. The FTC can take issue with a merger only if the effect may be "substantially to lessen competition or tend to create a monopoly." 10 In recent years there has been considerable discussion about what this means exactly. At one time, antitrust enforcement officials and the courts seemed to view market concentration as the end as well as the beginning of merger analyses, that is, mergers would be presumed legal or illegal based simply on the market shares of merging firms. 11 Little attention was given to just how the merged firm would affect the industry's ability to raise prices and restrict output.

In the early 1970s the courts began to realize that relying solely on numbers could be misleading, 12 and enforcement authorities have followed suit. Today, although I will not consider concentration and market shares important, they represent the beginning and not the end of our competitive analysis. This approach is exemplified by the FTC's "Statement" released on June 21, 1982, 13 and the Department of Justice Guidelines issued that same day (and updated recently, 14). The commission's "Statement" and the Guidelines note that measures of concentration will be considered important as a preliminary indication of the need for an agency response. But both also stress the importance of other market characteristics, including entry barriers, demand and supply responsiveness, and possible efficiencies.

Since these guidelines are better understood in their application in the abstract, I will now turn to the FTC's substantive criteria for analyzing natural gas pipeline acquisitions. We have reviewed quite a few such mergers in recent years, the two most noteworthy being Internorth's acquisition of Houston Natural Gas and MidCon's acquisition of United Energy Resources. 15 In both cases, major interstate natural gas transmission pipeline companies were joined. Some of these merging companies also had very significant intrastate pipeline subsidiaries.

Among the first questions pipeline companies raise is why
the FTC is concerned about acquisitions in an industry regulated by the Federal Energy Regulatory Commission (FERC) and similar state agencies. First, as a matter of law, the regulatory scheme does not foreclose enforcement of Section 7 of the Clayton Act. Second, and more important, the regulatory scheme does not foreclose the benefits that can be obtained from competition. Even in pervasively regulated industries, of course, not all gas is one, consumers can benefit from competition that forces firms to conduct their business more efficiently. Competition and regulation can go hand in hand to spur more efficient performance. There is also good reason to believe that such FERC-subsidized pipelines might file a rate with FERC that is less than the maximum that FERC might permit.

In any case, competition is growing and regulation is declining in importance in the pipeline industry. The best way to explain the significance of this trend to merger analysis is to first consider a world without any regulation. Let us assume that pipelines tend to conduct their business as contract carriers. In such a world, nonpipeline firms buy gas in the field, contract for transportation, and eventually sell the gas in the field, contract for transportation, and eventually sell the gas to the pipeline or use it themselves. In this simple case, pipelines might have to lower the price of their gas to attract customers. If they tried to raise the price, consumers could buy gas in the field and also transport it themselves. Their competition with pipelines, however, could still exercise market power by maintaining the transportation rate at the maximum level permitted by law. Under its new rule, FERC allows pipelines to charge lower transport tariffs, in order to inject more competition into the markets. Pipelines could limit such competition by agreeing not to offer the discounts that FERC permits. FERC's new rule also suggests another way pipelines could exercise market power, simply by deciding as a group not to opt for FERC's simplified transportation program.

This explanation of the FTC's interest in gas pipeline acquisitions usually prompts a second question: Given the increasing level of competition in the natural gas industry, why is enforcement of the Clayton Act contemplated? The FTC recently responded, in a somewhat different context, by saying that growing competition does not mean an acquisition poses no threat. "In fact, it is just that emerging competition that must be watched in connection with mergers that facilitate the suppression of such competition."22

From the abstract issue of how firms might exercise market power, we turn to the more concrete matter of whether an acquisition may increase the likelihood that firms would exercise resources.

Both these worlds offer some insight into the present situation in the pipeline industry. First, rather than contract carriage by pipelines, the predominant form of competition is purchase and resale, some aspects of which are regulated, but others are not. For example, the price at which pipelines purchase most gas is no longer regulated, and thus they could use market power to lower the price of gas in the field. Although FERC regulates the resale price for some pipeline gas, pipelines might still exercise non-jurisdictional sales and cannot require pipelines to pass through any decrease in acquisition price to those customers. While FERC does regulate the resale price for pipeline gas, pipelines might lower the price of their gas to increase their margins if FERC would permit a higher rate of return. This higher rate of return might be sustainable in a noncompetitive market but not in a competitive one. Finally, on the selling side, pipelines might exercise market power by raising the price to non-jurisdictional customers. FERC has also issued a new order that contemplates an expanded role for contract carriage, providing pipelines an opportunity to exercise market power under a simplified transportation program, conditioned on non-discriminatory access to it. If pipelines opt for contract carriage and if FERC enforces nondiscrimination, pipelines could not directly force gas prices below the competitive level in the field or directly raise prices above the competitive level in consuming markets. If they tried to lower the price, producers could sell directly to consumers and use the pipelines as contract carriers. If they tried to raise the price, consumers could buy gas in the field and also transport it themselves. Their competition with pipelines, however, could still exercise market power by maintaining the transportation rate at the maximum level permitted by law. Under its new rule, FERC allows pipelines to charge lower transport tariffs, in order to inject more competition into the markets. Pipelines could limit such competition by agreeing not to offer the discounts that FERC permits. FERC's new rule also suggests another way pipelines could exercise market power, simply by deciding as a group not to opt for FERC's simplified transportation program.
such power. This depends on a host of considerations, but we
usually begin by asking whether buyers of the product or ser-
vice sell to the product and geographic markets are defined, we turn
in other areas, particularly the Gulf Coast, the number avail-
able may be somewhat larger.

In recent years debate about the weight that should be given to various
characteristics has led to policy changes that take an attempt to
deal more realistically with the competitive effect
of horizontal acquisitions. In 1982 this policy process led a
unanimous commission, including members appointed by three
different presidents, to conclude that an "increase in the
threshold market share is clearly justified," and that
"consideration of additional characteristics... may provide a
more accurate picture of competitive dynamics." Thus
Merger Guidelines raised the threshold market-share level and intro-
duced a new index to measure concentration, the Hirschman
Index (HHI). In a nutshell, the likelihood of a
government challenge to a merger between competitors is based
in part on the postmerger HHI index and the size of the
HHI change caused by the merger. For example, a challenge is
unlikely if the HHI value after the merger is below 1,000
"points." A market would have an HHI value of 1,000 points if
there were ten firms of equal size in the market. The HHI is
obtained by expressing market shares in decimal form (that is,
less than one) and then squaring these, and then summing. By
definition, the result is multiplied by 10,000 to obtain the raw HHI
score (or "points"). For example, a market with three firms
having market shares of 50 percent, 30 percent, and 20 percent
would have an HHI of 1,000. If the HHI in a market is above 1,000 but below 1,800
a challenge is still unlikely if the merger changes the HHI by
less than 100 points. If two pipelines, each possessing 5
percent of a market, were to combine, the change in the HHI
would only be 50. If a pipeline with 10 percent of a market
were to acquire another pipeline with a 5 percent share of the
market, the change in the HHI would be exactly 100.

If the postacquisition HHI is more than 1,800, the thresh-
hold standard changes somewhat. In such a market, a challenge is
unlikely to challenge an acquisition that increases the HHI by
less than 50.

Using these benchmarks, many of the pipeline acquisitions
that the FPC has reviewed raised no competitive problems;
either the merging firms did not participate in the same
markets or one of the firms had a relatively small share of a
market. In some recent cases, to which I have already referred,
two substantial mergers joined two substantial firms in markets
with HHI's above the 1,000 or 1,800 thresholds.

Marc G. Schilling
This quick review of concentration methodology should not
give the impression that the commission's pipeline analyses
begins and ends with the invocation of the HHI or similar
exotic antitrust jargon. In fact, the most important innova-
tion of the commission's Merger Statement was to stress
increased reliance on evidence beyond market shares, one of
the factors being the magnitude of entry barriers or entry impedi-
ments.27 No matter what the HHI, firms cannot exercise market
power if new firms can easily enter the market and drive prices
back to a competitive level. In some markets, however, impedi-
ments could prevent or delay this kind of response, and one is
simply the length of time it takes to enter a market.26 The
longer it takes to enter, the more significant is the period
during which market power can be exercised.

Government approvals also can delay entry.27 FERC must
certify many new pipeline services, and in determining approval
it applies a balancing test, in which gains from certification
(such as a reduced price to consumers) are measured against
losses to the incumbent pipelines (which might result in higher
prices to consumers in other markets).28 Under Order No. 436,
however, FERC will offer expedited certification procedures to
potential entrants willing to assume the entire risk of the
venture. Although this option may make entry easier in some
cases, new entrants would still face a higher risk than do
incumbent pipelines. This higher risk is the type of impedi-
ment to entry that might permit incumbents to maintain non-
competitive conditions in the industry.29

Another factor the FTC is likely to consider is the
availability of rate and throughput information, concerning
which FERC required the filing of very detailed data. Even
under Order 436 pipelines must file selective discounts with
FERC.30 Where such information is available, collusive agree-
ments are more likely to persist. Firms participating in such
agreements could detect and retaliate against any deviation in
an agreed upon tariff.31

Among the numerous other characteristics considered when
analyzing a merger, to which both the FTC Merger Statement and
the Department of Justice Guidelines offer a guide, I would
like to mention one, efficiency. If the consolidation creates a
more efficient firm and such efficiency could only be
achieved through the specific acquisition, the FTC will account
for this in its merger analysis.

If after due consideration the commission has reason to
believe an acquisition may substantially lessen competition, it
will attempt to find a remedy that resolves the competitive
problems yet permits the merger. This procedure has been most
productive in the energy area, where the anticompetitive ef-

cfects of the acquisition are sometimes only incidental to its
main purpose. Most of the assets in such acquisitions are in
markets where no anticompetitive issues are likely to arise,
and the commission seeks a consent order leading to divestiture

of problem assets. As noted earlier, if the order is nego-
tiated, the parties are allowed to merge. Only when no work-
able consent arrangement is achieved will the commission seek
an injunction or file an administrative complaint.

I would like to offer a final comment about where we
obtain the information for analyses, which we sometimes have to
complete in about one month. We rely on data provided by the
merging firms to some extent, but we also need information from
the rest of the industry and from relevant regulatory agencies.
Any such help is always welcomed and can contribute to a speed-
der and more thorough assessment.

Notes

also, Pflueger, Plaine, and Whittmore "Compliance with
Divestiture Orders under Section 7 of the Clayton Act:
Analysis of the Relief Obtained," Antitrust Bulletin 17
(1972): 19; and Elzinga, "The Antimerger Law: Pyrrhic
4 Reporting requirements are set out in 16 C.F.R. S800 et
seq. Some mergers and acquisitions need not be reported.
This depends on the size of the acquisition and other
criteria.
5 16 C.F.R. S803.10(b).
6 16 C.F.R. S803.11.
7 Federal Trade Commission, Eighth Annual Report to Congress
Pursuant to Section 201 of the Hart-Scott-Rodino Antitrust
Improvement Act of 1976.
9 See, for example, FTC v. Bass Brothers Enterprises, Inc.,
(1963).
12 United States v. General Dynamics Corp., 415 U.S. 486
(1974).


15 Intermountain Inc. and Houston Natural Gas Corporation, Dkt. No. C-3168 (September 30, 1985); and MidCon Corp. and United Energy Resources, Inc., Dkt No. 9198; see 50 Fed.Reg. 42032 (October 17, 1985).


17 It may be that competition can ameliorate inefficiencies resulting from regulatory incentives. A large body of economic research suggests that regulation tends to induce a variety of inefficiencies and economic distortions unrelated to economies of scale.


19 Gas covered by Sections 102, 103, 107, and 108 of the Natural Gas Policy Act of 1978, 15 U.S.C. SS 3301 et seq., is either deregulated or free of controls because the ceiling price is above the competitive price.

20 FERC had also approved a number of special programs under which pipelines had offered price discounts to some customers. If FERC approves such programs in the future and if they are upheld by the courts, pipelines might attempt to exercise market power by refusing to offer the discounts that FERC permits. For a discussion of the legal status of some of these discount programs, see Maryland People's Counsel v. FERC, 761 F.2d 768 and 761 F.2d 780 (D.C. Cir., 1985).


23 FTC Statement Concerning Horizontal Mergers.
The Old World

Pipelines stand at the center of the natural gas industry and have done so for more than half a century. Their position has rested partly on size. Major pipelines are larger than most of the producers from whom they buy gas and the distributors to whom they sell it. By that measure, pipelines' dominance has been growing, and future mergers are likely to increase it further.

But size has not been the only or even the principal basis for pipelines' dominant role. From the beginning it also rested on their control of their own transmission capacity. It is technically possible to move gas by means other than pipelines. Like railroads in the nineteenth century, however, pipelines have a cost advantage so large that technical alternatives are economically not alternatives at all. To control pipeline transmission is to control natural gas transportation.

Control of transmission has rested with the pipelines themselves. Unlike railroads, pipelines have not been common carriers. Most of the gas they have transported has been their own. Although they have sometimes provided transportation for other shippers, they generally have been under no legal obligation to do so. Individual pipelines have had the power to determine whether gas moved into many markets; pipelines collectively have had the power to determine whether gas moved into virtually every market.

During the 1970s, federal wellhead price controls gave pipelines control over two additional strategic assets: physical supply and economic rent. These assets were two sides of the same coin. Gas was scarce because controls held price below the market level; it carried economic rent because supply did not satisfy demand at the regulated price.

Gas was scarce, and interstate pipelines controlled most of it. There were, in fact, two natural gas shortages during the 1970s. One was an immediate and real imbalance between supply and demand in the interstate market. The imbalance was the result of federal price controls, but the shortages were no less real for being a product of regulation. Not everyone was willing to buy gas at the regulated price could be supplied. Regulators, pipelines, and distributors became involved in a system of rationing intended to direct gas to its most valuable or politically sensitive uses.

The second shortage was longer term and was as much a matter of perception as of reality. The immediate natural gas shortages of the 1970s were part of the more general energy crisis of those years. Gas shortages coincided closely with the oil embargo and its aftermath, a dramatic increase in world oil prices, and local shortages of gasoline and other oil products. The gasoline shortages were, like those in natural gas, partly a reflection of real changes in the relationship of demand to resources. By the 1970s it was no longer economical-
ily feasible for the United States to be self-sufficient in oil, much less to serve as a supplier of last resort to its allies. Dependence on imports need not have led to shortages; without regulation, the changes would have been reflected solely in higher prices. For oil as for natural gas, it was price controls that transformed changes in demand and resources into shortages and rationing. Natural gas price controls were in some sense responsible for the immediate shortages should have been beyond debate. At some price, supply and demand would match. However, it was commonly believed that the required price would be high and that most of the response would take the form of reduced demand rather than increased supply. Supplies of natural gas and oil were believed not merely to be finite (which undoubtedly they are) but to be finite in a way that required regulation of their use. The Fuel Use Act for natural gas and mandated automobile mileage limits for oil were the response to short- and long-term shortages, just as curtailment regulations and rationing were the response to the real immediate one. Natural gas and oil were not commodities that should be competitively marketed but scarce and precious resources that should be managed. For gas, pipelines were the central managers. Economic rent went with the interstate pipelines' physical supply. Interstate customers who were able to buy gas did not just receive the physical commodity. They also received an economic benefit equal to the difference between the current price and the price they would have paid in a competitive market. It was a significant economic benefit, and it could be obtained in only one way by purchasing natural gas from interstate pipelines' system supply. Pipelines' control of transmission, supply, and rent laid the basis for their position in the natural gas industry down to about 1980. It was a position largely undisturbed by competition. The natural gas that pipelines sold insulated from effective competition from other fuels, and each pipeline was at least partially insulated from effective competition from other sellers of gas itself.

Competition from Alternative Fuels

Competition came mostly from oil. It was an ideal competition. Oil prices generally changed little over the short term. The Texas Railroad Commission once saw to their stability; early in the 1970s that role shifted to OPEC. When oil prices did change, they generally moved in only one direction: upward. Even if oil prices had been more flexible, it would have been difficult for them to match the price of gas. The large gas surplus accumulated as a byproduct of oil exploration depressed prices through the 1950s. When increased demand absorbed the surplus, federal price controls restrained the price increase that market forces would have dictated. Only briefly during the 1960s was price competition from oil a serious factor.

During the 1970s some customers installed equipment that allowed them to burn oil as well as natural gas. Today this equipment allows close price competition between gas and residual oil in the boiler fuel market. Originally, however, the equipment was a response to the unavailability of natural gas rather than to its price. Almost everywhere, gas was cheaper if it could be obtained at all.

Gas-Against-Gas Competition

Major natural gas markets generally were served by more than one pipeline, but minimum commodity bills and other legal restrictions limited competition among them. Potential competition from new pipeline entrants was even more restricted. Entry depended on approval by the Federal Power Commission, which could require a year or more, if it was obtained at all. Only rarely did interstate pipelines enter major new markets after the 1960s.

Entry barriers were even greater for nonpipeline sellers. In legal theory, direct sales by producers to end-users lay outside the jurisdiction of the FPC. In regulatory fact, interstate sales could not be made without FPC approval. Nonpipeline sellers also faced the problem of obtaining transportation. Pipelines that could transport gas to end-use markets generally also sold gas there, and they were unlikely to transport gas that competed with their own systems. Finally, even if the sale was approved and transportation was available, the nonpipeline seller generally faced the competition of pipeline system supply selling at a below-market price. Direct sales by producers to distributors and end-users developed a modest role in the mid-1970s. It was the natural gas shortages that temporarily broke down the barriers to entry. For the FPC, direct sales were a way of ameliorating shortages without general abandonment of wellhead price controls. For pipelines, the sales were not a competitive threat because demand by customers in any case exceeded the supply of pipeline gas. For customers who bought directly from producers, the lower price of system supply was irrelevant because that gas supply was not available to them.

The basis for the direct producer sales also imposed limits on their role, however. Neither the FPC nor the pipelines had any interest in promoting such sales where system supply was available, and purchasers had no reason to buy directly from producers at a higher price when they could buy pipeline system supply at a lower one. The volume of gas sold directly by producers was never large during the 1970s, and such sales largely disappeared toward the end of the decade as more adequate pipeline supplies undercut their role.
The Forces of Change

Control of three assets—transmission capacity, supply, and economic rent—effectively protected pipelines against any challenge to their dominant role during the 1970s. Since about 1980, however, these assets have either diminished in value or partially slipped from pipelines' control. Change began with supply. The FPC dramatically increased the wellhead price for new supplies during the early 1970s. In the Natural Gas Policy Act of 1978 the Congress both ratified the higher price ceilings and began the gradual elimination of those ceilings for new interstate supplies.

By 1980 the natural gas shortage was largely over; by 1982 the problems of allocating a scarce supply had been replaced by those of managing a surplus. Pipelines no longer controlled a scarce physical commodity.

Today they also no longer control a significant economic rent. That rent came from the difference between the average price pipelines paid for gas and the market value of that gas. The difference initially increased as a result of the large rise in oil prices in 1979, but it then began rapidly to diminish as gas prices increased while oil prices first stabilized and then declined.

By mid-1985 no major pipeline had average gas costs significantly below the current market level; for a number of pipelines, average gas cost was well above that level. Pipelines still controlled some gas priced well below market, but they were also contractually committed to take or pay for other gas that was priced above the market. The economic rent was gone.

Pipelines still generally controlled their own transmission capacity, however. In practice, political and regulatory pressure and the threat of antitrust probably caused pipelines to control transportation when they otherwise would not have done so. But for the most part, they still were able to refuse to transport gas that would compete with their own system supply.

Pipelines did transport gas for distributors and end-users in their own market area when they could not get gas from the system supply. In 1984, unlike 1975, pipelines did not lack system supply to sell; supply they had in more than ample quantity. But in some cases their gas was too expensive to compete with alternative fuels or other gas sellers. Transportation of gas that a customer had purchased from a producer then was preferable to losing the customer altogether.

Control of pipelines' transmission capacity has now passed, in part at least, from the pipelines to their customers and regulators. Order 436 does not directly require pipelines to transport gas, but it makes an offer that few pipelines are likely to refuse. There still exist major uncertainties about the order, and the resolution of these may significantly affect its impact. It seems clear, however, that in many cases non-pipeline marketers will be able to require pipelines to transport gas in competition with the pipelines' own system supply. Pipelines' ability to use their control of their transmission capacity to shield themselves from competition has been substantially diminished.

Regulation as well as economics will influence the competition. Transportation costs may be lower for pipeline system supply than for competing gas, but regulation also gives advantages to nonpipeline marketers, namely, flexible prices and a profit incentive to sell their gas.

The Cost of Moving the Gas

For sales customers, the implicit transportation rate for pipeline system supply is the nongas portion of the commodity rate; for transportation customers, it is the pipelines' transportation surcharge. In either case, if regulation is not to bias the outcome of the competition, these two rates must be the same. In fact if not in name, pipelines must have a single set of transportation tariffs governing the terms and rates for both system and nonsystem supply. If explicit transportation rates vary with the season and with distance, sales rates must vary according to the same factors and in the same amounts.

Flexible Prices

Nonpipeline marketers are free to adjust price at frequent intervals without public notice, and under Order 436 pipelines are allowed to discount their rates for transporting nonpipeline supply. System supply is priced through the PGA procedure, requiring pipelines to announce in advance the price at which they will sell their gas for a six-month period, and in recent decisions the commission has been unsympathetic to pipeline requests to be allowed to discount their sales rates to meet competition.

Profit Incentive

Marketing brings no profit to pipelines. They must resell gas at cost, and the rate base on which they earn their return is largely devoted to transmission and storage. Pipelines might be able to win the marketing competition, but it is not clear why they should want to do so.

The future role of pipelines in the natural gas industry, therefore, is in doubt, and that doubt inevitably leads to uncertainty about the future structure and operation of the industry itself. The pre-1980 world will not come again, but whether the new world will be an evolutionary modification of the old or a radical transformation world is an open question.
The New World

The physical supply of natural gas will come to market through pipelines because there is no economical alternative. The question concerns ownership of the gas. Will pipelines also own the gas they transport, buying it from producers and reselling it to distributors and end-users? Will the marketing function be performed by some other organization, possibly marketing companies affiliated with producers, distributors, or the pipelines themselves, or independent marketers not affiliated with companies in other sectors of the natural gas industry?

Two very different futures are possible. In the first, pipelines are still the principal marketers. For various reasons some large end-users prefer to buy their gas from independent marketers, but most buyers find they cannot improve on the combination of price and supply security offered by the pipelines.

In the second future, pipelines serve principally as suppliers for the smaller distributors. The larger distributors and large end-users purchase their gas from nonpipeline marketers. This second future is most likely to develop if the pipelines voluntarily relinquish the marketing role, and they are likely to do this only if their own unregulated marketing affiliate assumes a major part of that role. In the second future, therefore, the principal marketing function is divided between marketers affiliated with the pipelines and other marketers. The illustration assumes that the latter would be independent, but they might instead be affiliated with producers or distributors.

The second future thus would involve competition between marketers affiliated with the transporting pipeline and those lacking that affiliation. In such a structure, abuses would be possible, and allegations of abuse would be certain. Thus, one part of the second future probably would be closer regulation of pipelines' transportation rates and allocation of transmission capacity between affiliated and nonaffiliated shippers.

Note

1. A number of pipelines adopted transportation tariffs that were expressly limited to situations where the pipeline was not able to satisfy demand from system supply.

ORDER 436 AND LOCAL DISTRIBUTION COMPANIES: A POLITICAL AND POLICY PERSPECTIVE

Frederick E. John

Southern California Gas Company (SoCalGas), like most other members of the natural gas industry, is still grappling with the recent actions of the Federal Energy Regulatory Commission (FERC). The FERC is taking action on the numerous petitions for rehearing of Order 436 (issued on October 9, 1985), and the commissioners have heard the diverse views of the industry, regulatory community, and legislative interests on the "deferred" block billing proposal. These events highlight the fluidity of the regulatory changes occurring in today's natural gas environment.

At this point some background and perspective on SoCalGas seem appropriate.

Background and Perspective

SoCalGas is the largest natural gas distributor in the United States. It is not a combination gas/electric company and so does not have a captive utility electric generation market to which to sell its gas. SoCalGas operates and maintains about 38,000 miles of pipeline and serves more than 4 million meters, of which about 3.8 million are residential customers. The service population is about 13 million.

Note: The author wishes to express his appreciation to Steven W. Miller in preparing this material.
In 1985 the sales profile of SoCalGas was as follows: residential, 28 percent; commercial/industrial, 25 percent; utility electric generation, 34 percent; and wholesale, 13 percent. More than 50 percent of this market has the ability to switch to alternate fuels, such as propane, No. 2 fuel oil, and No. 6 fuel oil (both high and low sulfur). Today, about 70 percent of the SoCalGas revenue dollar goes to the purchase of natural gas, which is a specific example of the point stressed by Commissioner Stalon.

Since mid-1985 SoCalGas has become the largest single purchaser of spot market gas in the United States. This averaged almost 25 percent of total system supply during the last half of 1985. During that period the delivered price of spot market gas dropped from $2.73 per MMBTU to $2.25/MMBTU, on a weighted average basis, and SoCalGas generally could purchase gas on the spot market for $.50 to $.60 per MMBTU less than the marginal cost of its interstate pipeline supplies. In 1983, the system served the rate base at $.70/MMBTU; today, its about $1.85/MMBTU. This equates to about $26.00 per barrel of oil at the burner-tip, which is a very competitive rate.

Since May 1983 SoCalGas has passed through rate reductions to its customers totaling about $335 million. During the past five years it has given customers cash refunds of about $530 million. So rate reductions and cash refunds total more than $885 million.

Order 436: A Fork in the Road

Why am I citing these statistics? I want to demonstrate that SoCalGas is a major player in this transition of the gas industry and to emphasize that although Order 436 represents "a major fork in the road," the transition has been occurring for the past seven years, since the passage of the Natural Gas Policy Act of 1978. There has been a rapid escalation in wellhead prices in an effort to avoid future gas shortages. As the wellhead price increases flowed to the burner-tip, a consumer revolt began, best exemplified by large industrial users switching off gas to alternate fuels. This market loss led to a gradual but steady reduction in prices.

The FERC's Order 380 series, which eliminated minimum bills and minimum takes for variable costs, was a significant first step by federal regulators to provide LDCs with the flexibility needed to gain access to supplies other than through the traditional pipeline monopoly.

Almost concurrently with the Order 380 series, the FERC allowed pipelines/ producers to market their "surplus" gas through special marketing programs, blanket certificates, off-system sales, special discount rates, and so forth. But these programs were originally designed to exclude LDCs from the spot market. Industrial customers with the ability to purchase lower cost alternate fuels were the primary beneficiaries of these programs. The FERC (with some help from the D.C. Circuit Court of Appeals) recognized that these programs were and still are only a Band-Aid approach to attainment of the goal expressed by Commissioner Stalon: increased discovery and development of natural gas supplies through prices that will provide the opportunity to market gas and through access by the ultimate users to the gas supplies.

At the state level the PUCs and LDCs also adopted special rates for certain classes of customers in an effort to regain those industrial customers who switched to alternate fuels. These customers Order 436 and with it is a minor state by state Moron within the industry. Producers do not like the block billing concept because they claim it will discourage exploration and development of new reserves. Yet, they love the open access to transportation. Pipelines do not like the open access to transportation unless (a) the producers renegotiate their high priced gas contracts and relieve the pipelines of take-or-pay obligations and (b) the service obligation of the pipelines to the LDCs is redefined. Distributors are generally reluctant to relinquish their rights to pipeline transportation capacity and their "share" of the pipeline's system supply. This is especially true where the LDCs' end-users and/or state regulators refuse to relieve the LDCs of their obligation to serve a customer who jumps off and on the distribution system.

There is also a split within the LDC community over the benefits or detriments of block billing depending on the amount of "old" gas that the distributor's pipeline has, whether the distributor is a full or partial requirements customer, and how much gas the distributor took from the pipeline over the past three to five years.

The state PUCs are scratching their heads trying to determine the ultimate effect of Order 436 at the state level. With limited staff and a myriad of other issues facing them in the areas of telecommunications, electricity, water, trucking, railroads, and so forth, the PUCs have to decide whether to allow intrastate transportation to avoid the horrid "bypass" and how Order 436 will affect the long-term reliability of gas supplies to the LDC's customers.

End-users are split between the high priority (so-called core) market and lower priority (so-called industrial market) as the battle lines are drawn between value-of-service and allocated cost-of-service, whether through rate design for sales or for transportation.

These things are not confusing enough (based on the different interests/desires of the producers, pipelines, LDCs, state regulators and end-users), we cannot leave out the federal and state legislatures. Despite the fact that only one piece of major natural gas legislation has passed Congress since 1954 (the NGPA) and took more than two years of bitter debate
before enactment—some segments of the industry still think that Congress can solve the present transitional problems by deregulating old gas now, relieving the pipelines of their take-or-pay obligations, and requiring mandatory carriage at the federal and/or state level. Political reality says that this will not happen in the foreseeable future.

Some state legislatures see legislation prohibiting bypass as the answer to the PUCs' and LCDs' fears. But this is only a "fingerprint" in the "dike" approach to the bypass problem. Finally, we cannot ignore the role of the judiciary. For example, the U.S. Court of Appeals for the D.C. Circuit has shown no reluctance to tell the FERC or other federal regulatory agencies that in their rush to provide for deregulation and "to allow market forces to work" they cannot ignore prior legal precedent or the laws of Congress, such as the Natural Gas Act.

At the state level many courts in the producing regions of the United States are faced with decisions on how the PUC policy affects on state regulatory laws. I have briefly described the position of the various players in the industry. What is the common thread? They are all attempting to shift the risk away from themselves to someone else.

The Future

Where does this leave us in 1986, seven years after the enactment of the NGPA? SoCalGas starts with a system average rate of $4.85 per MMBtu, which is a bargain for the general consumer; a huge and relatively stable core market for natural gas; increased flexibility to respond to changing demand, competition, and prices; no cost constraints on sales through least-cost purchasing practices. This latter comes at a time when competition among SoCalGas's various suppliers for both sales and transportation is at its zenith. A key issue is how much reliance SoCalGas will place on traditional pipeline gas merchants versus gas transporters. In the past, interstate pipelines took a paternalistic and benign view toward the LCDs who allowed and/or encouraged this attitude. But emerging competitive forces will change this relationship and force the LCDs to make their own decisions. The "old buddy system" between pipelines and LCDs is over.

Despite increased gas purchasing flexibility, SoCalGas still has limited flexibility as to how to allocate costs among different customer classes. The major constraint stems to a great extent from the California legislature's intrusion into the rate design arena. The present life-line/baseline legislation in California limits severely the ability of the LCDs to remain competitive in the industrial markets over the longer term. The limitation is caused by a formula in the law from which it is difficult to deviate. The result to date is a system average rate of $4.85 per MMBtu; a Tier I residential rate (up to 72 therms in the winter) of $3.55 per MMBtu; and a Tier II residential rate (above 72 therms in winter) of $8.20 per MMBtu and commercial rates of $6.50 per MMBtu.

Of course, SoCalGas is faced with the thrust of competition not only from alternate fuels but also from other gas companies both within and outside the state—exemplified by a drive to serve a burgeoning incremental gas market for enhanced oil recovery and cogeneration in the San Joaquin Valley. Finally, SoCalGas can provide service to end-users on an unbundled basis—separate purchase, brokerage, transmission, storage, and distribution—provided the state regulators allow these services to be priced on an economically rational basis.

SoCalGas can compete with LCDs such as SoCalGas expect any pipelines select strategies to deal with the increasingly competitive gas market? (1) Greater volatility of pipeline rates. As pipeline competition becomes more intense, sales and transportation rates will change more frequently than every six months in the PUC policy affecting on set dates tied to a pipeline's generating rate case. (2) Pipelines will attempt to shift costs to less competitive markets and services through new rate schedules, changes in rate zones, and new methods of allocating common costs, such as the "rate band" and peak/low load provisions of Order 436. (3) Pipelines will try to discontinue services for which they are not adequately compensated. Many will become transporters instead of merchants to avoid take-or-pay exposure if they cannot market their gas. (4) Pipelines will become more aggressive in bypassing distributors, especially high cost pipelines in competitive markets and those close to existing industrial end-users. (5) Pipeline competition may result in lower prices for gas, which could affect the prices charged by distributors. (6) Pipeline competition will induce distributor competition. Pipeline competition for sales and transportation markets will meld regional gas markets into an integrated natural gas market. (This may be accelerated by the pipeline mergers discussed by the other panelists today) and the distributor's ability to serve its marginal customers will depend on the net back price it can offer the producer. Net back price includes the marginal value of the gas to the end-user less the cost of the transportation or sales margin charged by the pipeline that delivers the marginal unit of gas and the margin charged by the distributors.

How can the LCDs improve their competitive positions? They must be able to obtain concessions from pipelines for reducing the pipelines' risk. (As described above, pipelines are uncomfortable with increased risks from competition). But one must be careful to avoid arrangements that have anticompetitive implications. The state PUCs may have to play a major role here to provide a possible state action defense.

If an LCD has abundant storage it may want to make direct purchases of gas from producers whose prices are less expensive than the pipeline's system supply. The LCD may be able to
store the gas for winter use. An LDC may be able to make direct purchases from the producers at lower prices than a pipeline by promising to buy gas from the producers at a very high load factor. An LDC may also be able to tailor gas purchase contracts to the needs of a specific customer and "split the margin" between the producer and the LDC. Efforts by an LDC to buy gas directly from the producers will probably require enhancement of its staff to do the job properly. The state PUCs must recognize that these increased costs in the short term are just and reasonable in order to obtain the long-term benefits of a reliable low cost supply.

As discussed above, a major challenge for the LDCs will be finding the proper balance of pipeline system supply and direct purchases. The LDCs may have to pay some of the pipeline's take-or-pay penalties in order to obtain the proper mix, and the state PUCs must recognize these costs as just and reasonable.

Transportation for large industrial end-users is a good way to shift risk from LDCs to end-users and procurers. However, this is a difficult philosophical and psychological hurdle for LDCs to overcome, because it requires a shift from the traditional role of merchant to transporter. The LDCs should also consider offering storage for large industrial customers as a separate service.

All these strategies will differ depending on whether the LDC is a captive or in a competitive market. Captive distributors should support the FERC staff's imputed load factor policy: Rates would be calculated using higher volumes than the pipeline is likely to realize in the test year, for example, highest throughput achieved over the past six years. This is very important to LDCs that have to deal with pipelines which might choose to concentrate in less competitive markets. Captive distributors must also watch out for cost shifting. Pipelines with a mix of competitive and noncompetitive markets will try to shift costs to those that are less competitive. Finally, captive distributors should encourage the pipeline to open its system to transportation. Although this approach will not keep the pipelines' fixed charges down, it will ensure that the LDC is not also paying noncompetitive wellhead prices.

Those distributors in a competitive market should watch out for bypass, especially if their pipeline suppliers are near lower industrial end-user customers. These LDCs must continue competition among their pipeline suppliers and should support the FERC's move toward market-based pricing. This will force higher cost pipelines to meet their lower cost competitors' prices.

Conclusion

If many of these concepts sound familiar to state regulators, it is because the same principles are being applied today in the telecommunications industry and have already been used in the airline industry to deal with their deregulated environments. Deja vu will be the watchword as the state regulators see the transition of the gas industry to a more competitive environment. The state PUCs must continue to confront the issue of how to regulate a company that is a monopoly dealing in a competitive business. The state PUCs must provide the LDCs with sufficient flexibility to accomplish the objective of securing adequate supplies on a least-cost basis.

Notes

1 Pipelines complain that LDCs have no obligation to take from pipelines, but pipelines have a continuing obligation to serve LDCs. These pipelines forget that in the 1970s, in a period of gas supply shortages, the pipelines with the blessing of the Federal Power Commission (FPC) and the federal courts, abrogated their service obligations to LDCs, that is, curtailment. One very positive thing developed as a result of these curtailments: SoCalGas, like other LDCs, sought a diversity of supply. In our case we bought gas from Canada and the Outer Continental Shelf of California. This diversity provided for more competition among our traditional pipeline suppliers, and we are now seeking the benefits of this competition.

2 Ed Schroer, the new chairman of AGA, said at a recent NARUC annual meeting that "bypass is not yet a social disease but is close to becoming one."

3 See Wall Street Journal, December 3, 1985, "Reagan Administration's Deregulation Drive Often Thwarted by Appeals Court in Washington."

4 Gary Stewart, Iowa Office of Consumer Advocate, has said that end-users should not assume any of the risk. I disagree with his view, and the more progressive state regulators are already on record indicating that there must be some sharing of risk by the end-users as they attempt to secure adequate and competitively priced gas supplies. Those same consumer groups who so vociferously advocate transportation for end-users must recognize that as end-users seek to purchase their own gas and have it transported from the wellhead to the burner-tip they must be willing to assume more risk.
5 Despite the trend of nature of competition, state PUCs must still recognize that LDCs are monopolies with certificated franchise areas, and the state commissions must resist efforts by other LDCs to invade these franchised areas unless it is shown by substantial evidence that the existing LDC is not able to serve the market.

6 The netback pricing concept has been the subject of controversy, which may be nothing more than a semantical problem. LDCs cannot sell gas for less than "cost." Cost includes a minimum distribution margin, pipeline margin, and the wellhead price of the gas. Thus, the maximum wellhead price an LDC can pay equals customer value less the minimum LDC margin less the pipeline margin, that is, netback. Some people have erroneously concluded that the producers would be forced to accept the netback price. This is not accurate. The producer will accept the market price. But if the netback is less than the market price, the LDC will not be able to serve the market.

Richard O'Neill, Marc Schildkraut, Robert Means, and Frederick Johns have addressed various structural issues facing the natural gas industry. These encompass the effect of recent mergers among interstate pipelines, the emergence of new marketing facilities, and the evolution of new strategies by the LDCs to deal with the increasing competition being experienced at all levels of the industry. At least one theme is common among the papers. Newly experienced competition in what was formerly a highly regulated industry is resulting in changes in behavioral patterns, including consolidation, mergers, and new marketing entities. These developments are new to the natural gas industry but are probably common to other industries experiencing similar pressures.

Johns, who represents the largest U.S. distributor of natural gas, explains that Southern California Gas has become the single largest purchaser of spot gas in the country. Thus, it is a major player in the transition toward greater competition, at least as a beneficiary of reduced costs from the increased competition upstream of its operations as a distributor. In forecasting an increasingly competitive natural gas market, he anticipates more volatility but also a more integrated market. He seems to suggest that a prescription for success in the interim period for the regulated distribution monopoly is to encourage and take advantage of the competition among its suppliers. However, the distributor might need to avoid competition itself (for example, by-pass). There are going to be problems enough, according to Johns, for distributors in dealing with changes in local rate design, where cross-
subsidiaries among previously supplied services will be under extreme market pressure, without additional competitive pressures.

Mergers are a particularly visible sign of the structural changes occurring in any industry. The papers indicate that the no less true for the natural gas pipeline industry, in which certificates of public convenience and necessity act to segment and protect markets. O'Neill and Schildkraut recognize some of the serious pressures raised by increased concentration in the basically monopolistic interstate pipeline industry and in particular the basis for review of mergers by the FTC and the Department of Justice. Specifically, they note there has been a change in how mergers are judged and in particular in the analytical methodology for making judgments on the acceptability of a merger. Enforcement of the law under the Hart-Scott-Rodino Act, Schildkraut informs us, has moved from postacquisition litigation to a preacquisition review and determination. No longer is the legality of a merger judged solely and simply on market share data. Now, more general considerations of how a merger affects the industry's ability to raise prices and restrict output are equally important. In terms of determining the benefits of any resultant increase in efficiency from increased concentration by merger, Schildkraut notes that "consideration of the regulatory scheme does not forecast enforcement of Section 7 of the Clayton Act" and that "the regulatory scheme does not forecast the benefits that can be obtained from competition."

Schildkraut and O'Neill consider the positive aspects of mergers in the pipeline industry as economies of scale, more efficient integration of facilities, lower transportation costs, and the concept of failing firms. Analytical results by FTC and EIA confirm that the natural gas wellhead market is reasonably competitive. At the pipeline level the recent number of large mergers do not appear to have materially increased the market power of the new integrated system. However, the power is already relatively high in most if not all markets, a result not inconsistent with the originally designed monopoly nature of the natural gas interstate transmission industry. The question of whether the merger is still appropriate is not judged explicitly in these papers. What is addressed is the clear fact that the industry is currently experiencing the need to change in its operation and cost structure - a change induced by demographic changes in demand, including a permanent substantial loss of demand in some market areas.

Since the market appears to require a change in the industry's structure, several questions are raised by these papers. Who should benefit from the changes? If, on the other hand, efficient firms should prevail, does the post-merger regulatory structure of the industry - which has granted price subsidies which are unequally dispensed among firms - really allow the more efficient firm to prevail, or does it only promote the firm with a regulatory advantage? Indeed, who are the most efficient?

In addition, it was recognized that competition is on the rise in the pipeline industry, but the exercise of market power may occur in nontraditional ways. These include raising the rates at which gas is transported for others; failing to discount in a nonuniform manner; collectively raising the selling price to consumers; and alternatively or simultaneously lowering prices in the field in line presumably of absorbing (via stockholders) some costs that cannot be passed through to the ultimate purchaser.

Means described the growing demand for offering and charging separately for services and noted the market is acting to sever the functions of transportation, storage, purchases, and sales. He described the complex new set of entities of affiliated and nonaffiliated organizations - transporters, pipelines, marketers, brokers, and traditional pipelines - all of which may act to increase or decrease exercise of market power.

Returning to the four benefits from mergers, the second and third more efficient integration of facilities - the lower transportation costs - seem worthy of greater scrutiny given the large concentration of market power that appears to exist. In particular, given the evolution of the regulatory scheme, it is pertinent to ask: What evidence is there that through these recent mergers transportation costs have indeed been lowered? Have facilities been integrated and have cost savings been realized leading to the elimination of presumably redundant facilities and overhead costs?

Means questioned directly, and the other authors only obliquely by reference to market power exhibited through transportation costs, the contribution or role a nondiscriminatory transportation program plays in affecting a pipeline's level of market power. This seems to be a crucial point, especially given the growth of new unregulated marketing affiliates that may have distinct advantage in arranging transportation.

Additional questions are raised as to how transportation costs should be reviewed in order to provide maximum opportunity for real competition. Questions about availability of capacity seem equally pertinent.

To sum up: We are moving from a highly concentrated transportation system to a new highly concentrated transportation system which holds the potential. But not necessarily the guarantee, of greater efficiency and competition, presumably with the characteristics of lower cost.

The reader is left with many unanswered, perhaps unanswerable questions and the feeling that major considerations still must be addressed by the regulatory structure with respect to how efficiencies are to be realized and facilitated for the public good.
Deregulation is, of course, the hot topic in the natural gas industries these days. The industry is in transition; the time of the monopoly is over. We are rapidly moving toward a world of competition not only in production of gas but also in transmission and distribution. Not uncommon to times of major upheaval, those who have to deal with the results of change are divided into two groups: those who dislike change and the uncertainties they bring and those who welcome the opportunities offered by them. This is certainly the case in the natural gas industry.

A primary discussion has centered on the effects of free enterprise in the natural gas industry. Brought about by the Federal Energy Regulatory Commission's (FERC) Order 436 and the associated notion of anticompetitive possibilities arising from industry mergers, I am reminded of the saying about closing the barn door after the horse has gone. Well, the fact is, the horse named "Free Enterprise" is out of the barn. Unfortunately, many in the industry are still standing around looking at the empty barn wondering if someone took the hay as well. It is not only too late for that, but also that is the wrong approach.

Robert Means accurately concludes there now exists a possibility that in the future the principal marketing role will be divided between marketers affiliated with the pipelines and other marketers. "In such a structure, abuses would be possible and allegations would be certain." In his excellent paper, Richard O'Neill details the mergers and acquisitions taking place in the oil and gas industries. He discusses the recent combinations that have occurred in the pipeline industry, stating that "the acquisition of large natural gas pipeline companies by other companies with natural gas pipeline companies... is a recent phenomenon; 1983 marked the beginning of the consolidation trend."

O'Neill, too, believes that in this less regulated environment practices leading to antitrust issues may arise. He states that antitrust suits or the threat of suits may soon become a new source of discipline for natural gas markets. It is important to understand, however, that O'Neill's perception of the threat of antitrust suits is only a possible outcome of Order 436.

O'Neill further states that mergers can be beneficial if efficiency is increased and consumer prices are lowered. He also indicates that the potential exists for producing inefficient results and monopolistic profits. He points out that antitrust or market power can be very difficult to determine; that there are several tests for market power, none of them conclusive.

I would agree with O'Neill that antitrust is difficult to determine. I would add that beneficial mergers should not be precluded just because the antitrust threat exists. I firmly believe that the effects of mergers can be measured and dealt with by regulatory bodies if negative monopolistic effects are determined. Noticing the warning signs of anticompetitiveness becomes the simple application of common sense.

State and federal regulatory commissions have the obligation to watch for warning signs, and those signs of anticompetitive activity should be obvious. As O'Neill says, if sunk costs increase and the numbers of competitors decrease, the situation becomes ripe for monopolistic price abuse.

If a merger is going to be anticompetitive in nature, there will be adequate, if not blatant, advance warning. As the California Public Utilities Commission said on March 5, 1986, in its Decision 86-03-012 regarding PG&E's merger with Pacific Gas Transmission Company (PGT), "we remind both PG&E and PGT that this Commission has concluded that transportation for California end-users promises to promote economic efficiency for the state's gas industry as a whole. Hence, those who block or thwart such transportation for California end-users must bear the burden of proof that such action is in the best interest of all ratepayers." In the words of CPUC Commissioner Priscilla Crew regarding this decision, "the CPUC will be looking very closely at the PGT takeover by PG&E to see whether this is good or bad for competition."

Are there other signs of increasing likelihood of anticompetitive action? As Marc Schildkraut, Deputy Assistant Director, Bureau of Competition, Federal Trade Commission (FTC), points out in his paper, "the initial step in the FTC process is to determine how firms might exercise market power. The next step is to determine whether an acquisition might..."
increase the likelihood that firms would exercise such power. Schildkraut states that they first ask consumers of the product or service if they, the consumer, could defeat market power by product switching. Industrial customers of natural gas local distribution companies (LDCs) can switch energy sources, so this is yet another area regulators must watch -- the loss of industrial customers on an LDC system. These are the customers whose contribution to marginal costs in shielding residential and commercial customers from rate increases. However, it should be remembered that cost shifting as a result of bypass may really mean a reduction to preexisting subsidies for captive customers.

Schildkraut points out some of the historical warning signs of antitrust: (1) whether consumers can product-switch (as mentioned above), (2) whether there is total control of a geographic market, and (3) empirical research such as the Herfindahl-Hirschman Index (HHI) to determine market share benchmarks.

Regarding the idea of a geographic monopoly, it must be understood that, while this could be possible in the short run, it is unlikely in the long run. Vinod K. Dar pointed out in his January 23, 1986, article in Public Utilities Fortnightly, "The Natural Gas Industry: Gotterdammerung and the Phoenix": "The immediate and direct consequence of the...FERC's...decision to promote nondiscriminatory access to pipelines will be the advent of universal, long-distance, gas transportation in 1986. Long-distance gas transmission firms will, after a period of confusion and adjustment about their role in the gas industry, realize that they are competing for a share of the (LDC) (and possibly North American) gas transportation services market and not the gas sales market." I believe we are now in a "recruiting" period in which everyone in the industry is jockeying for position in this new world of natural gas markets. I hope that in this stage there will not be an overreaction to what only amounts to the possibility of an anticompetitive threat.

In his paper, Frederick Johns does not address structural issues, but in what he does not say, he makes an important point. In laying out to the CPUC what is needed for his LDC to meet the competition, Johns shows how much the commission is capable of doing to permit competition to occur.

The prevailing fear of too much market power wielded by LDCs is really fear of potential unfavorable outcomes. Regulators hold all the cards in terms of these outcomes. For example, a number of state commissions will be looking at the pipeline suppliers coming into their state and the LDCs that they regulate to see whether each has choices and alternatives and is making use of them in order to get the lowest cost reliable supply. State commissions correctly can reward or punish LDCs through reasonableness of operations reviews. State legislatures can also provide similar incentives or guidelines. For example, Act 74 of the Pennsylvania legislature stipulates three points an LDC must show the state commission before rate increases can be passed on to customers: (1) it has participated before the FERC as to pipeline rate proceedings as well as purchased gas cost proceedings; (2) it has made efforts to negotiate or renegotiate contracts with suppliers; and (3) it has tried to negotiate or obtain lower cost gas supplies inside and outside, including the use of transportation arrangements with pipelines and other distributors.

To go back to the analogy of the horse leaving the barn, I can only feel vaguely sorry for those managers who are still looking into the barn. If they would just turn around, they would find that the horse is just out exercising in the paddock, and he looks pretty good. In other, less facetious, words, the LDC's new world of gas regulation is right there waiting for us to make use of its possibilities. It is now up to us to show whether we can sell gas to a noncaptive market.

In order to succeed in the new gas market, each LDC must be innovative. The LDCs which do this well will provide service alternatives for their industrial and large institutional commercial customers. These creative alternatives could consist of: (1) transportation with and without system supply backup; (2) the LDC in the role of gas purchasing agent for its customers; and (3) gas-related subsidiaries entering nontraditional markets. I would disagree with Johns' statement that "deja vu" is the watchword. I think "precognition" is a more apt choice in the current gas market arena. We know what is happening, and we must have the ability to see into the future and make the world of deregulation work. It is possible. It is necessary. And I, for one, find the prospect of the future opportunities available to be exciting. Let us get on with it.
Part Nine
New Issues in Public Utility Costing and Pricing
The debate concerning cost allocation in public utility regulation consists of both rhetoric and substance. For example, the costing issues are relatively complex but not nearly as complex as some regulators perceive or as some public utilities indicate in their cost of service testimony.

There are substantive differences between the fully distributed cost (FDC) and marginal cost (MC) approaches, but these tend to be overstated and vary with specific cases. Largely overlooked are the substantive differences among the various fully allocated or FDC approaches and among the various incremental or MC approaches, and the numerous similarities between FDC and MC. Despite the rhetoric, the costing debate is important since the costing method selected affects cost distribution and thus income distribution. The different methods can produce substantially different results in rate design, that is, method selection can have a substantial effect on specific user classes.

Utility rate determination incorporates three stages. The first is the selection of a representative test period for which revenue requirements are established. The second is the allocation of revenue requirements to customer classes (the central focus of this paper). The third is the allocation of revenue requirements among users within classes (rate design).

In allocating interclass revenues (that is, across user classes), cost of service analyses are an imperfect but necessary tool. James Bonbright (1961) noted that cost studies are useful first approximations of equitable rates, given the pre-
Demand Allocation Methods

Of the approximately ten FDC methods which involve capacity allocations based on demand, two are worthy of mention: the Peak Responsibility (PR) and the Noncoincident Peak Responsibility (NPR) methods. PR, also known as the coincident peak or Wright method, considers peak demand and its timing but does not consider average demand or usage in the allocation of capacity costs. The allocation basis is the user class contribution to system peak demand. The prevailing philosophy is that those users who cause peak demand should pay for the capacity required to supply it.

There are several criticisms of PR. It assigns no capacity costs to off-peak users, although they contribute to the capacity required to permit the scheduling of routine maintenance. Another objection is that the assignment of all capacity costs to peak services creates the potential for unstable (shifting) peaks. A criticism with little merit is the argument that users with 100 percent load factors do not contribute to peak demand and thus should not be assigned any capacity costs. This overlooks the notion that all users at system peak demand are mutually responsible for it; that is, if the 100 percent load factor user transfers consumption from peak to off-peak, less system capacity is required.

NPR, on the class maximum demand or Hopkinson approach, considers peak demand but not its timing or average demand in the allocation of capacity costs. The allocation basis is the customer class contribution to the sum of the maximum demands for all user classes. By ignoring direct responsibility for system peaks, NPR allocates some capacity costs to all user classes. Criticisms include NPR's inadequate adherence to the cost causation standard (in regard to the users directly responsible for the system peak demand) and the inadequate recognition of the benefits of off-peak demand. Other demand-based FDC methods are simply variations of either PR or NPR.

Demand/Consumption Allocation Methods

Of the approximately twenty FDC methods which involve capacity allocations based on both demand and consumption, one is worthy of mention: the Averag and Excess Demand (AED) method. AED, also called the base-extra capacity or Greene method, considers peak and average demand but not the timing of demand in the allocation of capacity costs. AED initially estimates capacity costs assuming all users are operating at a 100 percent load factor and allocates them to user classes on the basis of usage. The extra or excess capacity costs are then...
allocated on the basis of the excess of maximum demand over average demand for each user class. NPR is generally employed in the calculation of the class maximum demand. AED makes minimal distinction between peak and off-peak demand, thus violating the cost causation standard. It has some validity, however, in its apportioning of some capacity costs to usage, that is, higher load factor customers have higher probabilities of peak contribution than lower load factor customers. From a load factor perspective, AED implicitly employs class load factors as a measure of peak responsibility; thus, benefits flow to low load factor classes. The AED philosophy of cost causation is that peak demand is only responsible for the incremental costs of new facilities incurred, that is, peak demand is not responsible for all system capacity costs. Other FDC allocation methods based upon both demand and consumption are simply variations of AED. Whether based on demand or on demand/usage, FDC methods suffer from several generic deficiencies (Rohr and Waddell 1983). All approaches other than PR permit user classes to shift usage from peak to off-peak (increasing capacity costs) without increasing their class allocation. This occurs under the condition when class or peak demand at system peak is less than average demand. The application of the various non-PR methods can result in the inefficient utilization of existing capacity and increased capacity requirements. There is also a tendency to channel unallocable costs (such as administrative and general) into customer category. In these forced cost assignments, value of service criteria may prevail. The conventional evaluation of the FDC methods includes validity as questionable standards (Herz 1966). Criteria having merit include the assignment of some capacity costs to off-peak users, although more are allocated to peak than off-peak users. The method should result in relatively stable cost assignments and should involve relatively simple cost calculations. A user class or service which makes exclusive use of a specific portion of capacity should bear the associated capacity costs. A more ambiguous standard is that each method should be evaluated on its recognition of maximum demand, average demand, timing of demand, load factors, and user class diversity.

Marginal Cost Methods

MC estimation methods are similar in that they focus on immediate and near-term future costs; they differ in the extent to which they stress short-run versus long-run costs, operation versus capacity costs, and so forth. In brief, the selection of an MC method involves trade-offs among price stability, allocative efficiency, adequate revenue generation, and administrative-transaction costs. In the case of electricity, three methods are worthy of discussion. They produce similar estimations of nongeneration costs, the primary differences being in the calculation of marginal generating capacity cost (MCC). The Cicchetti/Gillen/Smolenisky (CGS) method estimates long-run marginal cost (LRMC) assuming an optimal system expansion plan. MCC is the annualized capital cost of capacity being advanced to meet demand changes, that is, the cost savings from postponing capacity by one year. The Emery and Whitney (EW) approach estimates LRMC assuming a new optimal system. MCC is based on the optimal generation mix needed to meet the present load pattern at minimum cost. The National Economic Research Associates (NERA) method estimates LRMC incorporating a linear programming model. MCC is based on the least capital cost unit added to the optimal system to meet peak demands. MCC calculates a dynamic LRMC or the cost of additional output from an expanding existing system, that is, incremental cost as the system moves toward an optimal status. Advocates assert that dynamic LRMC most accurately reflects the cost of additional electricity consumption. EW and NERA calculate a static LRMC or the cost of additional output from a new optimal system, that is, a system is optimized for each output level. Advocates argue that static LRMC most accurately reflects the marginal cost concept portrayed in neoclassical economic theory.

In a regulatory context, the single most important difference between FDC and MC is that they involve reverse procedures. With FDC methods, revenue requirement determination is followed by cost functionalization, cost classification, interclass cost allocation, unit cost calculation, and finally rate design. One starts with the premise of the equality of revenues and costs, followed by an interclass cost allocation that produces the matching of costs and revenues. Obvious, there can be elements of witchcraft in the transition from cost allocation to rate design. For example, the costing analysis can be virtually ignored in rate design. Similarly, a method can be selected on the basis of producing allocations that justify a predetermined rate structure rather than on the basis of cost causation principles. With MC, the selection of the time horizon or planning period is followed by the estimation of marginal unit costs (functionalized basis), cost classification, rate design, and finally the reconciliation of costs and revenues. One starts with the premise of the equality of price and marginal cost, followed by cost adjustments to ensure compatibility with revenue requirements. Since unit costs are directly calculated as the bases for rate structure, MC methods generally do not involve interclass cost allocations.

With the exception of the procedural aspects, the differences between FDC and MC tend to be overstated. For
example, FDC or average cost is often used as an approximation of incremental distribution cost and incremental customer cost since MC calculation for these components is less precise than for production. Both MC estimations and FDC allocations may be adjusted in rate design for competition differences across markets. Both FDC and MC can be employed to provide a sophisticated rationale for value of service pricing. Both do not automatically generate cost-revenue equality. MC estimations can create rates needing adjustment before implementation, whereas FDC allocations can create rates needing adjustment afterward.

Both methods involve value judgments, for FDC in terms of cost, capacity, and administrative-general expense allocations, for MC in terms of estimation method selected (the choice of planning period and timing of new capacity), definition of incremental output, and revenue reconciliation. Both approaches necessitate judgments in selecting rating periods for time-differentiated pricing. For example, FDC and MC methods may produce similar peak demand rates, with any differences being attributable to rating period selection rather than being linked to the costing method employed. Both FDC and MC can be employed to control for cross-subsidization. Variances among FDC methods regarding the treatment of generation and distribution costs can produce divergent results comparable to those between FDC and MC methods (Austin and Stutz 1983).

Both allocations and MC estimations can provide regulators with important benchmarks for rate design. Since different FDC and MC methods generate divergent results, an option for the regulators and/or the utilities is to conduct costing analyses of multiple methods producing multiple benchmarks rather than single values. In this context, FDC results could be supplemented with MC estimations to provide upper and lower standards for specific rates.

Melody (1971) advocated the integration of the two approaches. FDC methods can be employed in allocating revenue requirements to specific classes and services, that is, in determining the rate levels for each. MC estimations can then be employed to design rate structures into these dual classes and services, that is, incremental costs assist (along with demand and market factors) in the structuring of prices. In brief, FDC can be the rate level standard, while MC can play an important role in rate design.

An Overview

The selection of a costing method involves important regulatory issues. One can derive insight by examining the natural gas, electricity, and telecommunications sectors.

In designing natural gas pipeline rates, the primary question has been and continues to be whether fixed (transmis-

sion and storage) costs should be allocated to demand or commodity costs. Given constrained capacity in the 1940s, the FPC employed the fixed-variable method, which resulted in directly charging users more responsible for the incremental capacity, that is, all fixed costs were allocated to the demand charge. In 1952, to assure that off-peak users bear some of the costs of transmission capacity, the FPC adopted the Seaboard method, which allocates 50 percent of fixed costs to the commodity charge. In the 1960s, with the loss of industrial markets, the FPC modified Seaboard by shifting some capacity costs back to the demand charge, the intent being to increase the competitiveness of natural gas.

In 1973, with natural gas shortages, the FPC adopted the United method, in which only 25 percent of capacity costs were assigned to the demand charge. The objective was to reduce the price discounts available to high load factor users. In the 1980s, with high surpluses (and associated marketing difficulties), the FERC moved toward the modified-fixed-variable method, whereby 75 percent of fixed costs are allocated to the demand charge, and the commodity charge absorbs only fixed production costs, purchased gas costs, return on equity, and income taxes. The FERC presently views Seaboard as the commencement point for costing but does acknowledge that adjustments may be necessary with changing market conditions.

The regulatory issues regarding natural gas costing include whether removing fixed or capacity costs from the commodity charge reduces pipeline risk, that is, helps retain industrial and other high load factor customers. There is the related question of whether shifting risk to consumers decreases existing rate-making incentives for pipelines. Finally, there is the issue of the effects of increasing competition on the allocation of risk and the implications of this risk shifting given increasing competition.

There are similar matters regarding capacity cost allocation in electricity. New generating capacity can be constructed to minimize costs rather than to meet peak loads; for example, the addition of base load capacity achieves substantially lower cost savings. One can argue that it is appropriate to allocate some of these capacity costs to energy rates, and AED does shift some of these costs into that component. One question is whether this transfers too much risk to the investor by making it more difficult to retain industrial markets. A similar issue arises with the classification of a substantial portion of distribution costs as customer costs, which provides a basis for utilities to impose relatively high customer charges on small consumers. The question is whether this shifts too much risk from the investor to the consumer.

In telecommunications, the traditional recovery of local exchange interstate costs through the settlements process has been replaced by a system of access charges. One component is a usage-based access charge on interexchange carriers to re-
cover traffic-sensitive (TS) costs. Another component is a flat access charge on end-users to recover nontraffic-sensitive (NTS) costs. The debate flows from local exchange and interexchange rivaling on the same local facilities. One can support, in principle, the use of access charges to recover certain local distribution plant costs. Given the cost causation standard, however, there are two critical costing matters. One involves the validity of the present division of costs between TS and NTS, which determines the relative magnitudes of the usage and flat access charges, and the other concerns the validity of the present separation of costs between intra- and interstate jurisdictions.

Conclusion

Each FDC and MC method makes certain assumptions concerning cost behavior and how cost should be reflected in rates design. It is thus unavoidable that the choice of a costing method will be influenced substantially by pricing objectives. Consequently, the debate perhaps should focus on underlying assumptions and not necessarily on whether an MC or FDC approach should be selected.

One can hypothesize that, similar to depreciation and pricing, the utility will tend to pursue a costing strategy which assigns it in attaining or maintaining market dominance, in maximizing long-run rate of return under regulatory constraint, and in minimizing risk. That is, the utility will tend to favor a costing approach which permits maximum flexibility in adjusting prices to changing market environments. For example, if incremental cost exceeds average cost (typical of electricity and natural gas sectors), the utility will most likely advocate FDC pricing to retain industrial markets and lessen risk. In contrast, if average cost exceeds incremental cost (typical of telecommunications), the utility will most likely pursue MC pricing to preclude entry and decrease risk.

Given these strategies, the primary responsibility of regulators is to impose constraints on pricing flexibility so as to protect consumers in captive or monopoly markets having the most price-inelastic demands. In the development and selection of costing methods, regulators should be attempting to minimize price discrimination and cross-subsidization. In this context, cost allocation can be viewed as a product of bargaining between firms and regulators, a process which has probably had more effect on regulated firm costing practices than have theories of cost causation. In brief, regulated firms operate similarly in the regulatory process and in the market (Owen and Braeutigam 1978). Thus, strategic use of the regulatory process to influence depreciation and cost allocation can be as important as pricing and technological innovation.

Notes

1 Common and joint costs are technically different. The former are caused by overall operation (provision of all services) of the firm, for example, overhead costs such as administrative and general. The latter are caused by only several services, such as capacity or plant used in common by peak and off-peak users.

2 Information on the various FDC method can be found in the publications of the Electric Utility Rate Design Study. An example is the Historical survey of regulation by National Economic Research Associates (1977), as well as the costing overview by Malko et al. (1981). Two other excellent sources are Caywood (1956) and Davidson (1964).

3 Variations of PR and NPR include the Modified Peak Responsibility, the Seasonal Peak Responsibility, the Monthly Peak Responsibility, the Weighted Peak, and the Peak and Class Maximum Demand Average methods.

4 Variations of AED include the Phantom Customer, the Complete Peak, the Modified Complete Peak, the Distributed Responsibility, the Capacity Credit, the Seasonal Distributed Responsibility, the Marginal Distributed Responsibility, the Modified Distributed Responsibility, the Excess Demand, the Peak Hour, the Demand/Consumption Sharing, and the Modified Class Maximum Demand methods.

5 MC pricing is not synonymous with incremental cost (IC) pricing, that is, MC is a theoretical static concept incorporating a finite change in output units. In regulation, MC pricing is generally applied to peak and off-peak consumers. In contrast, IC pricing is more flexible and pragmatic, and it is generally applied to an individual service; IC refers to the cost of adding or withdrawing an entire service.

6 An excellent source for discussion of the various MC methods is the publications of the Electric Utility Rate Design Study. Examples include the survey of marginal costing methodology by Temple, Barker, and Sloane (1979), as well as the costing overview by Malko et al. (1981). In recent years, many telecommunications and electricity firms have developed their own MC and IC methodologies.
REFERENCES


SELECTING METHODS FOR DETERMINING FULLY DISTRIBUTED AND MARGINAL COSTS

Thomas Austin and John Stutz

Because it is regulated, one of the hallmarks of the electric utility industry is the absence of a market mechanism determining prices for sales by and to electric utilities. Instead, the pricing of such transactions reflects the pricing philosophy developed in the course of regulatory activities, such as rate cases and other types of hearings, in response to current legal and regulatory requirements.1

The selection of a pricing philosophy involves a sequence of decisions. First, one must select a general approach, here the choice is between an analysis based on marginal or fully distributed costs. Next one must select a specific methodology for developing and analyzing the type of costs selected. Finally, one must deal with specific issues and problems associated with the chosen methodology and the particular situation of the utilities under regulation.

The development and implementation of a pricing philosophy is not static. Rather, it reflects the changing regulatory and economic climate within the electric utility industry. Substantial regulatory interest in pricing, as opposed to revenue requirements, is itself relatively recent. Most commentators trace the current interest in pricing to the late 1960s and early 1970s. Current pricing arrangements within the electric utility industry reflect the effects of PURPA.2 The so-called PURPA hearings, required under the terms of the act, provided a forum for a wide-ranging discussion of pricing philosophy in most if not all states. The Electric Utility Rate Design Study, sponsored by NARUC, EPRI, and others, provided the
background for much of this discussion. State commission actions in response to PURPA—defining, accepting, or rejecting the various standards—set the framework within which current pricing philosophy has been worked out. Current pricing issues within the electric utility industry are largely consequences of the continuing effort to maintain the basic decisions made during the PURPA hearing process.

In this paper, we will begin by reviewing briefly the role which PURPA, and the hearing process it engendered, had in determining the overall form of the pricing philosophy in use in the electric utility industry today. The bulk of the discussion will be concerned with particular issues related to the current implementation of this pricing philosophy. We will focus most of our attention on what are usually called cost-of-service issues and will deal with rate design to a much lesser extent. We will treat sales to and by electric utilities separately. The fact that these two areas reflect quite different pricing philosophies is itself one of the most interesting and important issues. Finally, we will speculate briefly concerning the possible implications of deregulation for electric utility pricing philosophy. Deregulation, if it occurs on a broad scale, could influence electric utility pricing at least as significantly as did PURPA.

**The Effects of PURPA**

PURPA is a complex and in some ways contradictory piece of legislation. Despite the time elapsed since its passage and the discussion it has engendered, its meaning and appropriate implementation remain the source of debate. Luckily, however, neither of these thorny issues concerns us here. Rather, we are more interested in its de facto effects in the area of electric utility pricing philosophy. In our view the regulatory response to the PURPA provisions dealing with cost of service and sales by qualifying facilities (QFs) has determined the general contours of electric utility pricing philosophy during the post-PURPA era.

The PURPA cost-of-service standard covers the sale of electricity by electric utilities. Broadly, it requires that pricing reflect the cost of producing the electricity in question. The obvious question is: What are the relevant costs? In the PURPA hearings throughout the United States in the late 1970s and early 1980s, discussion of this question focused on a choice between using a fully distributed (embedded) costs, which had been the standard for utility regulation before PURPA, and marginal costs. In the wake of the various PURPA hearings, it is clear that, for purposes of cost-of-service analysis, fully distributed costs have emerged as the choice of most regulatory agencies. In most states the concept of marginal costs has been relegated largely to issues of rate design and not cost of service.

With respect to sales by qualifying facilities to electric utilities, the decision went in precisely the opposite direction. Section 210 of PURPA suggested, but certainly did not require, that these sales be priced at marginal (or as they are called in PURPA, avoided) costs. However, the FERC regulations implementing this section of PURPA went farther than the act itself, effectively mandating avoided cost pricing.

The fallout from PURPA has thus been the development of two separate pricing philosophies, based respectively on fully distributed and marginal costs. The first governs sales by utilities, either to other utilities or to ultimate customers. The second governs sales by QFs to electric utilities. It is the ‘‘working out’’ of these pricing philosophies in their respective areas of application that leads to the issues to which most of the remainder of this paper is devoted.

**Fully Distributed Cost Issues**

Cost of service analysis based on fully distributed costs is basically an accounting exercise in which costs and associated revenue requirements are distributed among various classes of customers. Rates are then designed to collect class revenue requirements. A series of considerations confront the analyst after the choice of the fully distributed approach to cost of service is made. Once the approach has been determined, it is often assumed that the major choice has been made and only minor technical points remain to be decided. While this position is rarely stated quite this openly and forcefully, we have found that it underlies much current discussion, particularly the presentation and analysis of embedded cost-of-service studies in utility rate cases. Our experience shows quite the opposite -- a number of major decisions remain after the decision to employ fully distributed costs.

A cost-of-service study begins with the adoption of a twelve-month period referred to as the ‘‘test year.’’ Based on data for this year, costs, revenues, and rate-based tests for the utility are developed, usually in accordance with the Uniform System of Accounts. Next, certain costs are directly assigned to individual customers or classes of customers. The costs are then apportioned among the customer classes by a three-step process: (1) functionalization, in which the uniform accounts are accumulated into functional categories such as generation, transmission, and subtransmission; (2) classification, in which the costs in each of the functional categories are classified as being determined by energy usage, peak demand, or the number of customers in a class; and (3) allocation, in which costs are allocated to customer classes in a manner consistent with the preceding classification through the use of allocation factors based on class energy consumption, contribution to system peak, and so forth.
A cost-of-service study results in the apportionment of the company's rate base (investments) and expenses among the various customer classes. The rate of return has often been specified for each class, revenue responsibilities can be determined through the use of the ratemaking formula; class rate base, revenue responsibility equals allocated expenses plus allocated rate base times the class rate of return.

In our analysis of the current cost-of-service studies based on fully distributed costs, we have identified four areas in which there are significant differences in approach: (1) the treatment of generation plant-related costs; (2) the classification of distribution system costs as customer-related; (3) the assignment of diversity benefits in allocating subtransmission and distribution system costs; and (4) the lack of a compelling argument for any particular method of general and administrative costs. In each of these areas, current positions and accepted practice exhibit wide latitude, extending far beyond what one might expect given the treatment of these issues in the NARUC Manual. Here, rather than discuss each of these areas, we will focus on the second as an example. Those interested in a more complete treatment can consult our discussion in Public Utilities Fortnightly.

A distribution system is constructed in response to two primary requirements: the need to serve customers' peak demands and the necessity to blanket the service area with conductors so as to allow connection of customers. This raises two questions. First, can the costs of the distribution system be meaningfully separated into separate cost pools for peak demands, on the one hand, and the need to blanket the service area, on the other? Second, if a reasonable method of separating the costs is available, on what basis should one allocate (and ultimately collect) the costs of blanket? These questions have a direct bearing on the computation of distribution costs.

The traditional utility response to the first question is that the costs of "blanketing" can be obtained by constructing estimates of the cost of building a phantom distribution system that connects all customers to the system but is so designed as to be able to serve little or no load. The NARUC Manual describes the two methods which can be employed to develop this system. The minimum size method requires the analyst to estimate the costs of reconstructing the distribution system, employing the smallest sizes of the smallest size currently being used. The minimum intercept method uses a statistical technique, linear regression, to estimate the cost of components "sized" to carry a zero kilowatt load. With either method, the cost of a phantom distribution system is suggested and is taken as to be the cost of blanket the service area. The difference between actual and phantom system distribution costs is assumed to be related to peak demand.

These procedures raise a number of interesting issues. Should one regulate on the basis of a completely hypothetical construction? Use of the zero intercept method currently gives negative estimates for phantom system component costs. Should the method be modified (if so, how), or should the method be discarded? A minimum size system can, in principle, serve a significant load. How can this be reconciled with the aim of separating the satisfaction of demand from the need to blanket the service area? The minimum system development involves a great deal of judgment. Does the degree of judgment totally undermine the use of the procedure? On all these points competent analysts have exactly opposite opinions. Consider the last, for example. Volume 46 of the Electric Utility Rate Design Study contains, back-to-back, two articles that raise this point. The first proposes a substitute for the zero intercept method, while the second advocates abandoning the use of any minimum system.

The second question -- how should one allocate the costs of blanket -- is also the source of serious dispute. In fact, the traditional sources on this matter reach opposite conclusions. The NARUC Manual and those that follow it assume that these "blanketing costs" should be allocated on a customer basis. In contrast, James Bonbright and those who follow him argue that these costs are, in fact, unallocable.

In the face of such divergence, one might expect that the use of a minimum system would be a lively topic among rate case analysts, but our experience is the opposite. Most cost-of-service studies use some type of minimum system, apparently without any attempt to confront the issues we have raised.

Pricing Issues Related to Marginal Cost

Currently, marginal costs are the dominant pricing philosophy only in the area of sales by QFs to electric utilities. This is not to say that some states do not use marginal costs as a basis for cost-of-service analysis. Nevada requires this approach, for example. Nor is it meant to suggest that marginal costs play no role in electric utility rate design. In fact, they are utilized for that purpose in a number of states. However, as we noted previously, consideration of the PURPA cost-of-service standard reaffirmed the dominance of fully
distributed cost analysis as the pricing philosophy appropriate to electric utility cost-of-service analyses.

With respect to the pricing of sales by QFs to electric utilities, the situation is completely different. The FERC rules implementing Section 210 of PURPA effectively mandate that these sales will be made at the utility's marginal cost; formally, the requirement is that they be made at avoided cost, but from the standpoint of pricing philosophy, the terms marginal cost and avoided cost are largely synonymous. At first glance, it might appear that there is little difference between the use of marginal costs to price sales by QFs and other uses of marginal cost within the electric utility industry. Indeed, an examination of the treatment of these issues, provided by NARUC in Marginal Cost Ratemaking for Cogeneration of Interruptible and Backup Services, reinforces this impression. NARUC shows that the methodologies used to develop marginal costs, cost-of-service purposes are also applicable to the pricing of sales by QFs. However, those familiar with the development of cogeneration rates after PURPA will understand that this apparent similarity hides profound differences.

Here it is perhaps useful to recall briefly the issues current when marginal costs were actively being considered as an alternative to fully distributed costs for cost-of-service purposes. Those who are familiar with the Electric Utilities Rate Design Study, particularly Volumes 66 and 67, or who participated in the various PURPA hearings will recognize the fullness of issues as central to that debate. What methodology is most appropriate for the marginal costs? The available candidates included the "peaker" methodology, generation expansion planning, linear programming, and the production function method. Does the issue of "second best" undermine the economic rationale for using marginal costs? Do the data problems involved with "inverse elasticity" undermine the practicality of marginal cost computations? All these issues were debated again and again when marginal costs were being considered in the context of cost-of-service. However, when the focus shifted to sales by QFs, these issues largely vanished. Second-best pricing disappeared because there was no longer any need to justify the use of marginal costs. The FERC had mandated their use. Inverse elasticity vanished because, for sales by QFs, there is no revenue requirement constraint and so no need to apply inverse elasticity considerations.

Finally, and perhaps most interestingly, the lengthy methodological debates largely vanished as well. Anyone who has examined the various state approaches to the development of avoided costs has learned first hand what the term pragmatism really means. By and large, states have selected methods they find reasonable and applicable in their particular circumstances, often without much concern for the elaborate methodological issues raised when marginal costs were being considered under the PURPA cost-of-service standard.

All of this is not meant to suggest that conflicts associated with the development of marginal costs have disappeared. Rather, a new set of issues has emerged. In the context of sales by QFs, the major concern is when avoided capacity costs occur. This matter is paramount because the acceptance or rejection of the existence of avoided capacity costs often determines whether a cogenerator will face an attractive or unattractive purchase price from its local utility. In response to this essentially pragmatic concern, the focus has shifted from a discussion of marginal costing methodology in the abstract to a concrete examination of electric utilities' generation expansion plans, with the aim of determining when, and under what circumstances, the need for additional capacity will exist and, if it exists, whether it should in fact be avoided through the development of additional QFs.

A related concern is that of leveling the schedule of payments to QFs over a long period. Essentially, QF developers desire, and the FERC rules suggest that it is appropriate for utility commissions to provide a schedule of leveled payments which permit the developer to match revenues to financing requirements. The question of the proper procedure for leveling has elevated what was a minor part of earlier discussions to a major concern. Those familiar with the methods for developing marginal costs discussed in the Electric Utilities Rate Design Study will recall the debate concerning the relation of costs and revenue requirements when accounting for inflation. The relevance of this prior discussion to the earlier discussions of marginal costs lay in the fact that the first year's carrying charge often determined the marginal demand cost developed, particularly when one used the peaker methodology. With the interest in leveled payment schemes for QFs, this whole rather arcane and technical discussion has become an important issue for the current application of marginal costs as a pricing philosophy.

While the matters we have mentioned -- the existence of avoided capacity costs and the choice of a methodology for leveling of payments of QFs -- are the two most important current ones, they certainly do not exhaust the range of concerns. They do, however, clearly convey the "flavor" of the current issues involving the use of marginal costs as the basis for a pricing philosophy.

The Potential Effect of Deregulation

The preceding discussion, if nothing else, shows that the choice of a pricing philosophy and the issues raised by its
application are determined in large part by broad regulatory arrangements and by the economic environment. Our discussion of the shaping of marginal costs by the use of this approach to price sales by QFs is a classic example of the regulatory environment determining the relevant technical pricing issues.

Currently, a large-scale change in the regulatory environment looms — complete or partial deregulation of electric generation. One way this might occur is for one or more states to deregulate explicitly. For example, commissioners and/or commission staff in California, Massachusetts, and Illinois have indicated they favor transition to an environment in which the price of electricity is determined in part by a "market mechanism" which would replace the rate-baseding of new generating equipment. At this stage, it is unclear precisely what the market-baseding method. This has, revised interest in many of the "old" areas considered during the PURPA cost-of-service debate. At this stage it is not clear how far the FERC will proceed, since the issue has become entangled with others, such as the "price squeeze" addressed recently by the courts.

Of course, it is impossible to tell whether either of these versions of the future will come to pass. What seems most likely is a continuation of the current post-PURPA environment. For those actively engaged with the day-to-day, regulatory implementation of pricing philosophy, this means a continuation of the current case-by-case, issue-by-issue discussion of the various points raised in this paper.

The holding company future has interesting implications for the issues we have raised. State regulation would have much less control over the utilities' revenue requirements than is currently the case. Furthermore, commissions would have little say in the allocation of costs related to generation plant, since these would be received through FERC-approved rates. In this environment it would be natural for concerns to shift to the issues we have raised concerning their classification and allocation of distribution level and general and administrative costs. Thus, a holding company future might provide an opportunity for a more focused discussion of important issues related to the application of fully distributed costs to cost of service.

At the FERC there is currently some consideration of marginal cost approaches as a possible substitute for the fully distributed cost of service. Several recently completed studies have suggested that the application of fully distributed costs to cost of service.

Notes

1. The term pricing philosophy is, admittedly, a bit preentious. Unfortunately, we were unable to find a better term to describe the complex of issues we wished to discuss.


3. A cost of service study is, primarily, an attempt to determine the costs of serving various classes of customers (such as residential, industrial, street lighting) and, by extension, the revenues to be recovered from each class. Rate design is the development of tariffs which produce those revenues.

4. In part this is due to the compromises necessary to pass the act. Here a reading of the Report of the Joint Committee accompanying the act is quite helpful.
5 The regulations are contained in FERC Order No. 69 in Docket No. RM 79-55. The regulations were published in the Federal Register, 2/25/80.

6 Alternatively, the cost-of-service study can be used to compute class rates of return from cost data and class revenue requirements. In a typical rate case, both techniques are often used.


9 We use the term phantom to suggest simply that the system, however it is described, is not something any utility can or would build.

10 See the comments of Ralph Turvey, pp. 16-17, vol. 43, of the Electric Utility Rate Design Study. The comments refer to the NERA marginal customer cost, which Turvey correctly recognizes as essentially the same as all other minimum system constructions.

11 This point is discussed in the testimony and exhibits of Richard Pierce in Penn PUC Docket No. R-821945.


13 The articles we have in mind are those on pages 112 to 127.

14 For Bonbright's position, see his discussion of customer costs on pp. 347-49 in his Principles of Public Utility Rates. This position is developed more fully in The Electric Utility Rate Design Study, vol. 46, pp. 112-19.

15 The various debates and state commission decisions covered and recovered the same ground. Survey articles, such as "Trends and Topics" in the 10/9/80 issue of Public Utilities Fortnightly, give some idea of how things went.

16 Some sense of the state-by-state developments can be gained from "State Cogeneration Rate Setting Under PURPA," Parts 1-10, published in various issues of the Energy User News during 1985.


18 The Narrangansett doctrine states roughly that state commissions must reflect the results of the FERC wholesale rates in their approved tariffs. This area of conflict between state and federal jurisdiction is currently the center of much dispute.

19 The current developments at the FERC are reviewed, briefly, in the 11/18/85 issue of Electric Utility Week, pp. 5-6.
Marginal Social Cost as a Basis for Pricing Utility Services

William Vickrey

It is a basic proposition of neoclassical welfare economics that efficient allocation of economic resources requires that all prices be set at marginal cost. In a world of perfect competition, with no externalities or "neighborhood effects," no economies of scale in the neighborhood of the equilibrium, and clearly specified commodity characteristics, the action of the competitive market would bring this result about automatically. In the utility field, however, one is faced with significant economies of scale, interrelations between volume and quality of the service, and imperfections in the pricing process as it is applied to a multiplicity of circumstances. Pricing becomes a compromise between getting prices close to marginal cost for the sake of efficiency, the difficulties in financing whatever deficits might result, the practical difficulties of making price track marginal cost over time and space, possible conflicts between efficient marginal cost pricing and popular concepts of what is acceptable on equity grounds, and distributional effects.

Defining Marginal Cost for Pricing Purposes

Before attempting to balance these various considerations, it is important to clarify how marginal cost is to be defined for pricing purposes. If efficiency is to be served, prices must vary according to the conditions expected as of the moment the consumer commits himself to the use of the service, and the relevant marginal cost is an expected short-run marginal social cost, or SRMCS. This SRMCS should be a measure of the inclusive expected effect of a given use by a given user on others in the community, whether or not this is mediated through financial costs to the providing agency. It includes "externalities," such as effects on the quality of the service experienced by fellow users, as well as broader environmental effects. In order that customers should use the service as far as possible if and only if the value to them of the service exceeds the costs this action will impose on others, the price paid by a user should reflect this SRMCS, to the extent that other considerations such as revenue needs or distributional considerations permit.

An extreme example of the irrelevance of financial effects as recorded on books of account to the calculation of SRMCS is found in a telephone service, where the making of a direct-dialed call over a fully automated network has no significant immediate effect on the outlay of the operating agency, since the cost of the additional power consumption and wear and tear on switches and other equipment is relatively negligible. The SRMCS of making a given call consists almost entirely of the increased likelihood that another call will be frustrated by the busying of equipment by the given call and the consequent deterioration in the quality of the service to other users. Moreover, a low cost technology exists for making the charge vary in close conformity to variations in this SRMCS, by substituting an announcement of the current local call charge level for the dial tone, and for long distance calls giving a further similar announcement to those customers who pause before dialing the final digits.

It is also to be noted that the SRMCS of a given call cannot be calculated exclusively as a function of the state of business of the system at the moment but will depend on the load on the system as well as the state of the system at the moment. The time of day and the day of the week add to the load on the system and this will influence the marginal social cost of a given call. The marginal social cost of a call will increase as the load on the system increases. This means that the price charged will be greater in the period of low demand as opposed to high demand.

The Meaninglessness of LRMC ("Long-Run Marginal Cost")

One often finds in the literature proposals to use a "long-run marginal cost" as a basis for setting rates. The trouble with this is that in an operation producing a multitude of products with interrelated costs it is not possible even to define in any precise way what could be meant by such an LRMC.
any more than one could define relevant LRMCs for the hides and steak derived from the same cattle carcass.

The attempt to use a long-run concept seems to be motivated in part by the notion that in some sense LRMC is more inclusive in that it allows for variation in capital investment and thus would include a set of prices; then planning adjustments to capital installations according to a cost-benefit analysis based on predicted demand patterns and predicted application of the pricing policy, subject to whatever financial constraints may be applicable, and then eventually determining prices on a month-to-month, day-to-day, or even moment-to-moment basis, as pricing facilities permit, in terms of conditions as they actually develop.

Too often a rigid adherence to inappropriately timed financial constraints results in a pricing pattern that leads to gross inefficiency in the utilization of facilities added in large increments. In the setting of tolls on bridges, for example, a high fixed toll is often imposed from the start in an attempt to minimize early shortfalls of revenue to interest and amortization charges. When the indebtedness is finally paid off, tolls are often eliminated, sometimes just when they should be increased in order to check the growth of traffic and congestion and defer the necessity for constructing additional facilities.

Flexible versus Stable Prices

A long-run approach is sometimes advocated on the ground that it results in more stable prices. Price rigidity, however, exacts a high toll in terms of reduced efficiency. It may be argued that stable prices are required for intelligent planning for installations that commit a capital outlay of a given volume of service. There is nothing in an SRMC pricing policy, however, that precludes providing the consumer with estimates of the probable course of prices in the longer term. Even entrance of new marginal contracts to purchase specified quantities of service. If they are not to interfere with efficiency, however, such contracts should allow for the possibility of purchasing additional amounts at the eventual going rate, or for selling back some of the contracted-for output if this should prove profitable for the consumer.

Lack of flexibility in pricing has, indeed, been a major source of inefficiency in the use of utility services, whether arising as a result of the cumbersome of the regulatory procedures or of privately owned utilities or of bureaucratic inertia in publicly owned ones. At times it has even appeared that it takes longer to alter a price than to install additional capacity, whereas in terms of the underlying capability prices can usually be altered on much shorter notice than the time taken to adjust fixed capital installations and should be revised at frequent intervals in accordance with changes in demand and supply if efficiency is to be promoted.

The Forward-Looking Character of Marginal Cost

Since changes in present usage cannot affect costs incurred or committed in the past, only present and future costs are of concern in determining marginal cost. Past recorded costs are relevant only as predictors of what current and future results will turn out to be. Often gallons of gasoline pumped into a car is not determined by what the service station paid for that gasoline, but by the price expected to be charged to replace that gasoline at the next delivery. The substantial time-lag that often exists between a change in price at the raw material level and its reflection at the retail level is a pervasive market failure that contributes to the inefficiency of the economic system.

Another more important case in which future effects are of vital importance in calculating marginal cost occurs when congestion accumulates a backlog of demand that must be worked off over time. A particularly striking example occurs when traffic regularly accumulates in a queue during rush hours at bottlenecks, such as a toll bridge. The consequence of adding a car to the stream is that there will be one more car waiting in the queue from the time the car joins the queue until it is worked off, assuming that the rate of flow through the bottleneck will be unaffected by the lengthening of the queue.

In such a situation the marginal cost of a vehicle trip will be measured in terms of a number of vehicle hours of delay.
equal to the interval from the time of arrival of the car at the end of the queue to the time the queue is finally worked off. This is not measured by the length of the queue at the moment but will be determined by the subsequent arrival of traffic over an extended period. If traffic began to accumulate at 7:30, a car would be loaded at 7:45. If the bottleneck is at 8:00, but if the bottleneck will not be worked off until 10:00, the marginal cost will be 2.25 vehicle hours. Only one-quarter hour is borne by the added car, while the remaining two hours, if evaluated at $5 per vehicle hour, would indicate that under these conditions the toll that would equate the cost to the individual user with marginal social cost would be $10. In such cases marginal cost cannot be determined exclusively from conditions at the moment but may well depend, often to an important extent, upon what the effect of current consumption will be on conditions some distance into the future.

The Effect of Technological Progress on Marginal Cost

A similar problem arises when substantial changes in technology occur. There is then an especially important phenomenon in the telephone industry. If a new and better technology is known to be imminent but not yet ready for installation, any immediate installation of the old technology to take care of immediate demand involves a capital outlay that should, in principle, be called down, by the time the new technology becomes available. To a value determined by the competition of that technology, even though the useful economic lifecycle of the old technology may not be shortened by the installation. Very high prices are therefore placed on this interim and correspondingly high prices to hold back demand and defer the expansion of capacity until the new technology is available. Somewhat paradoxically, the imminence of a cost-reducing innovation may thus raise marginal cost rather than lower it in this interim period. Yet, if there were a third technology over the horizon that would be expected to require the second technology to be written off more rapidly, this would raise the competitive value of the first technology during the reign of the second. The effect would be to lower the marginal cost of adding to capacity during the period prior to the availability of the second technology. In practice, uncertainties and the interweaving of complementary technologies at various stages of the production of the services would tend to smooth these matters over, but there would remain an important efficiency-increasing potential in adjusting prices to hold back the growth of demand whenever substantial cost-reducing innovations appear imminent.

Wear and Tear, Depreciation, and Marginal Cost

Even in the absence of lumpiness or technological change, existing methods of charging for capital use often fail to give a proper evaluation of marginal cost. This is especially true where the useful life of a unit of equipment is determined more by amount of use than by lapse of time. In the extreme case of equipment that must be retired at the end of a given number of miles or hours of active service, or after the production of so many kWh of energy, and which, in one-horse-shay fashion, gives a uniform quality of service over its lifetime without requiring increasing levels of maintenance, the marginal cost of use at a given time will be the consequent advancing of the time of retirement of the equipment. The marginal cost of using the newest units will be the lowest and will advance over time at a rate equal to the rate of interest as the equipment ages and the advancement of replacement consequent upon use becomes less and less remote.

In a service subject to daily and weekly peaks, such as a local bus service, at any given hour the equipment required for service will be selected so that the marginal cost of its use will be minimized. This implies that the newest equipment will be allocated to the heaviest service, operating during both peak and off-peak hours. Equipment will be relegated to less and less intense service as it ages. The marginal cost of equipment use at a particular moment will be that for the oldest unit which has to be pressed into service at that instant. It will vary gradually over the entire range of demands, rather than dropping off to zero whenever the full complement of equipment is not required. At the other end, in the extreme case, the service provided would not necessarily be held constant by price variation over an extended peak period; under the conditions postulated it would be possible to provide for needly peaks by planning for the stretching out over time of the final service units of the oldest equipment. In this way the required peak capacity can be provided at a cost much lower than that which would be calculated by adding all the capital charges for the added equipment on this brief period of use.

Another way of looking at the matter is to appeal to the proposition that perfect competition under conditions of perfect foresight will produce optimal results. To this we suppose a situation in which vehicles are rented by the hour from a large number of lessors operating in a competitive market. For simplicity, initially, we assume all vehicles to be of the one-horse-shay variety, being equivalent to bundles of hours of active service, with the quality of service being independent of age up to a final "bubble-burst" collapse. So for simplicity we assume a steady state in which vehicles are
scraped and replaced at a constant rate over time, so that at any given moment vehicles are evenly distributed by age.

A common market rental price for all vehicles at any given time of the week will emerge, being higher as the number of vehicles in service at the time is greater. During any given week, each renter will have a reservation price for his vehicle, such that he will rent it whenever the market rental is above this reservation price and never when the market rate is lower. This reservation price will increase over time for any given vehicle at the market rate of interest, since a renter will rent his vehicle if and only if the net present value of the rental discounted back to the time of purchase exceeds some fixed amount. The owner would not want to rent his vehicle for a net present value less than he could have gotten by selling off his stock of service units at a hypothetical competitive market price below his reservation price. New buses will have the lowest reservation price and will be used on the heaviest schedules, while old buses will be held out and used only for peak service, as each bus age increases the need to less and less heavy service along the load-duration curve.

This pattern of usage can be regarded as resulting from a desire to recover the capital tied up in the usage units of each bus as rapidly as possible. It is related to the practice in electric utilities of using the newest units for peak service, in that case motivated in part by the tendency for the newer units to be more efficient in thermal terms. To be sure, occasionally new units are designed specifically for peaking service, so as to fit in with a correspondingly low capital cost, although this is a relatively recent phenomenon related to a slowing down in the rate of technological improvement in potential thermal efficiency.

In any case, where wear-and-tear is a factor, one cannot properly allocate depreciation charges primarily to peak service, however defined, nor should they be spread evenly over all service, much less spread evenly over hours of the week so that vehicle hours in off-peak load as laid up between runs at times during the peak. Rather, the depreciation charge per vehicle hour will vary gradually and in a positive direction with the intensity of use of the equipment at any given hour.

The analysis becomes a little complicated when equipment life is dependent on mileage, load intensity is baselined in later years as well as hours of active service, so that different rentals would properly be chargeable according to the nature of the service for which the unit is being rented. Also further analysis is required if equipment is obsolete at isolated terminals rather than at a central depot where a market could be postulated, or if the fleet contains vehicles varying in size or other characteristics. It would even be theoretically appropriate to charge $50 for depreciation per the same trip at the same time if made on vehicles with different origins or destinations. (In Hong Kong, indeed, the practice is to charge a flat fare on each route, but to differentiate the fare fairly elaborately as routes converge, this has the unfortunate result of unduly concentrating riding on buses with the lower fares, even where the higher fare buses have empty seats and are making stops in any case for other passengers.)

Costs of major overhauls that are performed at relatively long intervals would also complicate the picture. There are also problems associated with gradual or sudden changes in overall demand levels, or special events that can be anticipated sufficiently to present an opportunity for reacting in terms of a change in price. The picture can be further complicated if, as was discussed above, there are changes in available technologies or other changes in quality or cost. But the same method of analysis can be used to obtain appropriate results.

For the sake of simplicity the above analysis has been couched mainly in terms of a bus service, where it is not absolutely necessary to consider equipment being rented by the hour. The analysis is applicable wherever the useful life of equipment is in part a function of the intensity with which it is used, even if it is not economical to move it physically from one user to another.

Allowing for inflation

Ideally, allowing for inflation in the computation of marginal cost should produce a marginal cost in current dollars that when deflated will yield the same real marginal cost as if there had been no inflation. Unfortunately, most commonly used methods of accounting for depreciation under inflationary conditions fail this test.

A straightforward accounting method that bases depreciation charges on original cost and allows interest to be charged on the net remaining value at a rate that includes an allowance for inflation may be satisfactory from the standpoint of equity to the investor, but it distorts the time pattern of marginal cost. The investor is treated substantially the same as an investor in an amortizing mortgage with an interest rate adjusted to allow for inflation. But marginal cost will be overstated in the early years and understated in later years. If interest on the outstanding balance is to be charged at current nominal market rates, the correct results would be obtained by calculating depreciation (or in some cases appreciation) in terms of the change in the nominal market value. For example, in a noninflationary state with a 6 percent interest rate, a 20-year asset bought for $10,000 would have capital charges for its first year of use of $600 for interest plus $500 for depreciation (assuming straight-line depreciation to be appropriate), or $1,100. If inflation is 20 percent this charge should be, in terms of payment at the end
of the year, 1.2 ($1,100) or $1,320. If, however, we continue
to charge $500 for depreciation on the original cost basis and
interest at 6 percent (1.2) (1.06) = 1.272, the result shows that
the capital charges for the first year would be $3,220, or
nearly triple the proper amount.

To get the correct result with the use of the nominal market
rate of interest, we would have to consider that the market
value of the asset, which would have fallen to $9,500 in the
absence of inflation, has now risen to (1.2) ($9,500) =
$11,400. If we take this appreciation of $1,400 and subtract it
from the nominal interest charge of $2,720, we get the
correct capital charge for the first year of $1,320.

For the twentieth year the capital charges in the absence
of inflation would be $500 for depreciation plus .06 ($500) for
interest, for a total of $530. Under inflation, with a price
increase at the end of the twentieth year of 38.34, the correct
charge in current dollars is $20,319. The current dollar value
of the asset at the beginning of the year with the index at
$31.95 would be $15,974; writing this off and charging nominal
interest of 27.2 percent gives $20,319, the correct charge.
Charging only the original cost depreciation of $500 plus the
nominal interest of 27.2 percent on this balance, or $136, for
a total of $636, is of course deficient but is only an
equitable offset to the excessive charges in the earlier years.
Overall, for most growing utilities the excess charges on
the newer assets will outweigh the deficient charges on the
older ones. In any case, to allow both a market rate of inter-
est that includes the effects of anticipated inflation and also
a depreciation allowance adjusted for inflation (instead of
allowing for appreciation in money terms) would provide an
excessive return to investors and be unfair to customers. The
bias is especially crucial in the case of nuclear power, where
fuel-loading of the heavy components is subject to the
governmental operations. This bias is on top of that due to an
expectation of increased fossil fuel prices by the end of the useful life of such plants that would argue for the deferral of depreciation charges ev

Paradoxes in the Behavior of Marginal Social Cost

A strict calculation of marginal social cost in particular cases can produce what may appear to be quite paradoxical results. For example, in many circumstances it will be optimal, and even essential, to maintain at least a minimum frequency of service in off-peak hours with buses of a standard size, resulting in there being practically always a large number of empty seats in each bus. Under these circumstances the cost of carrying additional passengers is predominantly the cost of boarding and alighting, including the time of the
driver and the other passengers on the bus who are delayed in the process. This cost will be relatively higher if the bus is half full than if it is nearly empty. The result shows that the cost of a trip from a point near one end of the run to a point near the other end, at both of which points the bus is likely to be lightly loaded, may be smaller than for a shorter trip between points near the middle of the run, where the bus is likely to be more heavily loaded. This is not a
trivial matter; if it were there would be no sense for refusing
to let local passengers ride express buses over segments where the buses are almost always empty seats. It is highly unlikely that fares based on such a seemingly perverse behavior of cost
would meet with popular approval. Indeed, the original U.S.
Interstate commerce legislation contained prohibitions against
higher charges for shorter hauls than for the longer hauls
within which they might be included.

Another paradoxical example can occur in mixed hydro-
thermal electric power systems: An increase in fuel prices
could result in the marginal cost of power at particular times
being reduced rather than increased. If hydro dams are spill-
ing water at certain seasons of the year, increased fuel costs
may make it economical to increase the installed generating
capacity to make use of the spilling water, even for a briefer
period over the year than was previously worthwhile. If during
the wet season installed hydro capacity is more than sufficient
to meet trough demand, marginal cost during such periods will
be substantially zero, or at most limited to a small element of
wear and tear on equipment pressed into service. Expansion of the
installed hydro would expand the period during which the
low marginal cost is effective, so that while increased fuel
costs cause marginal cost to rise during the peak, the result
could also be to lower marginal cost in these intervals into

In the case of long distance telephone service, the

Marginal Cost of Heterogeneous Sets of Uses

It will often happen, for various reasons, that the same
price will have to be applied to a nonhomogeneous set of uses

Marginal Cost of
To set such a price properly, the marginal costs of the various uses within the set covered must be combined in some way to get a marginal cost relevant to this decision. It would be wrong, however, merely to average the marginal costs of all the uses for which this price is to be charged. Rather, the decision as to whether a decrease in a given price is desirable must consider the cost of the increments in output that will be bought as a result of the price change. In averaging the marginal costs of the various usage categories, the weighting will have to be in proportion to the responsiveness of each usage category to the change in price.

For example, if a price is to be set for electricity consumption on summer weekday afternoons, in a system where air-conditioning is an important load, consumption and marginal cost may be higher on hot days than on warm days, but it may be considered too difficult to differentiate between the two categories of days. An increase in the price for this entire set of periods may induce some customers to adjust the thermostat setting, but during hot days the equipment may work full tilt without achieving the reduction of temperature to the thermostat setting, whether or not the rate is increased, whereas on barely warm days there may be a more significant reduction in power consumption in response to a price increase. The marginal cost relevant to the setting of the price common to both types of day would change be determined predominantly by the lower marginal cost of the warm-day consumption and relatively little, if at all, by the higher marginal cost hot-day consumption.

Responsive Pricing with Escrow Funds

Modern technology, however, provides the technical possibility of making price track marginal cost very closely, without at the same time providing an ability for customers to respond quasi-automatically. With privately owned utilities, however, the regulatory process is too slow to permit prices established directly by regulation to be constantly adjusted to changing current conditions, unless indeed the regulators are to assume a large part of what are normally the responsibilities of management. The problem thus arises of how to allow the prices to be paid by customers to be varied by the utility management according to current conditions. Even if a formula could be devised that would require the utility to adjust prices to track short-run marginal cost, if the utility were allowed to keep the revenues thus generated this would set up undesirable incentives for the utility to skimp on the provision of capacity for the sake of driving up the marginal cost, price, revenues, and profits.

A resolution of this dilemma can be achieved by separating the revenues to be retained by the utility from the amounts to be paid by customers. We can make the "responsive" prices to be paid by customers vary according to short-run marginal social cost, while the revenues to be retained by the utility are guaranteed by a "standard" price schedule fixed by regulation, the difference being paid into or out of an escrow fund. Failure of the utility to expand capacity adequately would drive the responsive price up, curtailing consumption and limiting the amount to which the utility is entitled under the standard rates. At the same time revenues will flow into the escrow fund, but the only way the utility could draw on these funds would be to expand capacity sufficiently to drive marginal costs down and cause the responsive rate to fall below the standard rate on the average, while excessive expansion would result in the escrow fund being exhausted, with a corresponding constraint on the revenues derivable by the utility.

Responsive Rates, Emergencies, and Reserve Capacity

Standard rates could still vary by time of day, day of week, and season of year, reflecting the ex ante expectation at the time of the regulatory decision as to what marginal cost would be at those times. The difference between responsive rates and standard rates would then be due to unpredictable fluctuations in demand or supply conditions. Indeed, the most important advantage of responsive pricing is likely to be its applicability to dealing in an efficient way with extraordinary or emergency conditions.

In telephone service, for example, a storm or a breakdown of transportation service may trigger a spate of calling that overloads the system and causes a dangerous delay to various emergency calls, such as those involving fires, or accidents. While it is not clear how to block off or limit calls from a sufficient number of miscellaneous phones to assure that calls from priority origins get through, it is rather more difficult to provide priority for calls from miscellaneous phones to selected priority destinations. And many emergency calls cannot be readily identified at the originating region. Attempting to route such calls through operators is likely to overload operator facilities as well. A drastic increase in price at a time of emergency could abort a sufficient number of calls at the dial-tone stage to allow genuine emergency calls, whatever their origins and destinations, to go through without undue delay. It is difficult to conceive of any other method that can do as good a job of preserving essential service under emergency conditions.

In electric power service, implementation of responsive pricing would require providing the consumer with a signal of price changes to which he could respond, either manually or semi-automatically, as well as metering capable of recording usage at various rates. This need not be expensive. Existing meters can be retrofitted with a pulse-generating device.
mounted on the rotor shaft, such as a mirror and photoelectric cell, the pulses being transmitted to an electronic counter. When a change takes place in either the rate or the standard rate, a signal is broadcast causing the reading of the counter, the time and the new rate to be recorded in an auxiliary register, and the new rate to be indicated at a terminal accessible to the customer. The customer can then use the signal to shut off air-conditioning units or refrigerating compressors whenever the rate exceeds a critical level he selects, or cut back on elevator services, inhibit the initiation of power-using batch processors, or set indicators that could be read manually. Since the original meter dials would serve as a check on the performance of the add-on equipment, the latter need not be held to unduly expensive standards of reliability or resistance to tampering. Billing information can either be collected by meter readers or by remote meter-reading equipment. In the former case the communication channel need have only a very limited information rate, such as is the case for the low frequency signals often transmitted over the power lines to control water-heating equipment (for example, in New Zealand). Each new auxiliary register reading would be stored on a tape cassette to be collected by the meter reader for central processing. Alternatively, if remote meter reading is employed, the meters can be polled in turn during a period after each rate change to trigger a transmission of their readings by each of them in turn. This would require a transmission system with a higher information rate, either over the power lines themselves by carrier currents or via a separate channel. The communications technology would make the marginal cost of adding this capability to other communications channels fairly low, although the separate ownership of such other channels might lead to charges to the power company greater than relevant marginal cost. The costs involved would to a large extent determine how far it would be worthwhile to extend the responsive pricing system to the smaller customers.

With responsive pricing in place and a sufficient number of customers equipped to respond automatically, expensive reserve capacity requirements would be greatly reduced. Indeed, it could prove economical and be entirely satisfactory to limit reserve capacity to that called for by scheduled maintenance outages, leaving unscheduled outages to be taken care of entirely by economically efficient load-shedding induced by responsive pricing. At the first sign of a threatened shortage of supply or excess demand, the price can be raised sufficiently to instigate the immediate shut-down of most of the larger air-conditioning or refrigerating compressors, for example. This response is likely to be even faster than the bringing on line of many types of reserve capacity. If the outage is especially severe, or is expected to last for a long period, the price rise may be sufficient to induce the cut-back of elevator service by taking some of the elevators in multi-elevator banks out of service as soon as they have reached the top or bottom of the shaft, or the limiting of transit power to operation at the series notch. Decorative and advertising lighting might be suppressed, although customers might balk at the cost of installing automatic equipment and find it inconvenient to turn such consumption off manually. It might prove worthwhile to offer customers assistance or inducements to install automatic cut-out equipment.

The saving resulting from reductions in the cost of excess reserve capacity would far outweigh the cost of installing a responsive pricing system. Indeed the benefits go far beyond mere efficiency in normal use. Most of the havoc created by the blackouts that have occurred in New York in recent years would have been avoided if responsive pricing had been in place. In all probability most essential services would have been maintained and the system brought back to normal in a much briefer period. Even if, despite everything, areas must be cut off entirely, responsive pricing would greatly facilitate the subsequent picking up of the load when the emergency is over. It would be in order to arrange for the maximum price indication to be triggered by any more-than-momentary failure of supply to a customer. Then instead of having a whole avenue of motors trying to start up at once as the power is restored, with consequent load surges, poor voltage regulation, and malfunction of equipment, only essential usage would be picked up in the first minutes of restored power, with other uses picked up smoothly and gradually as the price is rapidly reduced to the normal level by small decrements.

The setting of the responsive price would have to be to a large extent at the discretion of the operating utility, although the regulatory commission could monitor the process and even attempt to establish guidelines according to which the responsive price should be set. The utility would normally never have an incentive to set the responsive price below marginal cost, since this would merely increase sales and hence costs by more than any possible long-run increase in revenues to the utility. To be sure, in the short run it might be able to draw on the escrow fund to the extent of the excess, if any, of the standard rate over the responsive rate, but since from a long-run perspective there will normally be other more advantageous ways of drawing on the escrow fund, this will not be attractive.

When marginal cost is below the standard price, which would tend to be the usual situation, the utility would in general have an incentive to set the price between the marginal cost and the standard price, since each additional sale produced by the lower price will yield an immediate net revenue equal to the difference between marginal cost and the standard price, offset only by the drawing down of the escrow fund by the difference between the responsive and the standard price.
When marginal cost is above the standard price, which with a properly designed standard rate schedule should happen relatively rarely, the utility would have an incentive to set the price at least at the marginal cost level, since to set it lower would tend to increase output at a cost in excess of anything the utility could recover. How much higher than marginal cost the price might be set would in theory be limited by the condition that the price could not be so high as to curtail demand sufficiently to drive marginal cost below the standard price. If the standard price pattern has an adequate time of day variation, as it does in most systems, this may seem, may be sufficient. Additional guidelines could of course be imposed by the regulatory commission for those rare occasions when this constraint might seem insufficient to keep prices within bounds.

**Demand Charges and Ratchet Clauses**

It should not be thought that utilities would necessarily avoid dramatic peak prices, whether for efficiency or for public relations purposes. Under existing practices, indeed the combination of demand charges and ratchet clauses produces some extremely high marginal charges that cannot be justified on any cost or efficiency grounds. A demand charge of $10 per kw of demand per month, based on a 30-minute demand measurement period, amounts to a charge of $20 per kwh for kwh consumed during the critical 30-minute period. If this is combined with a 90 percent 11-month ratchet, as is not uncommon in the industrial and commercial field, the total charge at a load peak is $218 per kwh for kwh consumed during the critical 30 minutes in November. This is not even likely to be for demand paid during the yearly system peak, and the level of the charge is utterly excessive as a charge for costs of the service connection to the individual consumer.

The attractiveness of this type of charge to the utility seems to be that it protects the revenues of the utility to some extent in the event of a general downturn in the economy. It is not at all clear, however, why the utility should be more entitled to such protection than its customers, many of whom are far less secure financially. The effect of such charges in lowering economic efficiency are quite severe, as when they induce customers to go to the expense of installing elaborate demand control equipment for the sake of lowering their power bills, but with little or no effect on the costs of supplying that power, or that their savings are obtained entirely at the expense of others.

Given the possibility of time-of-day pricing, there is little excuse for demand charges of the typical form. At best one could justify a far smaller demand charge based not on actual usage but on the size of the individual service connection as measured by the ratings of the fuses or circuit-breakers installed to limit current flow. Some improvement has been obtained by measuring demand in terms of consumption at the time of the system peak. However, this requires a fairly sophisticated response on the part of consumers and in the limit induces a kind of game-playing behavior. This is, indeed, a form of ex-post pricing that makes the price of consumption at a given time is not finally determined until the end of the month. Less radically, it seems likely that a customer demand measured over a more extended period, of say four hours, or taken as the average of the ten highest hours of consumption during the month, would produce a result that would correlate more closely with the contribution of the individual consumer to the system peak. In any case, hours known in advance to be off the system peak should be excluded from the calculation, as is indeed sometimes done.

**Cogeneration and Responsive Pricing**

Responsive pricing can perform a crucial role in integrating cogenerating facilities into an electric power system in an efficient manner. Many utilities have in the past been reluctant to engage fully in exchanges of power with customers that have the potential for generating power economically as an adjunct to their other activities. To some extent this reluctance is simply an expression of the urge to preserve a monopolistic empire. A more legitimate concern has been over the possibility that the cogenerator might vary his purchases and sales to the utility in a way that would be disadvantageous to the utility. With conventional pricing methods, it may be difficult to set prices in such a way as to promote an efficient pattern of purchases and sales. But with responsive pricing the price will be much closer to marginal cost at all times. Of course, there would be a margin between the price for sale and the price for purchase by the utility, and the smaller this margin the more efficient the results would be, opportunities for manipulation by the cogenerator to the disadvantage of the utility would be minimized.

The Marginal Cost of REVA (Low Power Factor)

AC power supply to a node is a vector consisting of two components: kilowatts, or kw, the component commonly thought of, and a second component, "reactive kilowatt-amperes," or kvar. Each of these two components supplied to the node will be the sum of the corresponding components of the loads drawing power from the node. It is because of this additive property, where the amount of supply is the sum of the amounts demanded, that it is to these two components that prices can properly be applied, in the same way that one can apply a price to hides
and to stalls, even though their production is inextricably interrelated. Common methods of charging for low power factor, which occurs when a consumer uses substantial amounts of kVA in conjunction with his kw, that are expressed in terms of power factor, or kva, which do not possess this additive property, violate this principle.

Resistive loads, such as incandescent lighting and heating, use virtually no kVA, and where this is the chief load, this component can be ignored. Electric motors are one of the main users of kVA but vary greatly in the degree to which they do so. Motors operating at a small fraction of their capacity are especially likely to draw power at a low power factor.

Costs of supplying power to a node can be thought of for the purposes of comparison as consisting of resistive losses, energy costs, and capacity costs, including charging current costs. Resistive losses are given a first approximation by the formula 2IR, where I is the current flowing through the apparatus, and R is the resistance characteristic of the apparatus, whether a generator, transformer, or line wire. This current, in turn, is the resultant of two components, one in phase with the voltage, proportional to the kw being handled, and the other at right angles to it, proportional to the kv. The product of this I and the voltage involved is denoted "kilo-volt-amperes" or kva. The relation between the three is the pythagorean relation,

\[ \text{kVA} = \sqrt{\text{kW}^2 + \text{kVAR}^2} \]  

(1)

The capacity of equipment such as generators and transformers is to a considerable extent determined by the ability of the insulation to withstand voltages and the insulation losses in its windings, on the one hand, and the ability to withstand voltage differentials, on the other. The capacity of such units is therefore usually specified in kVA. A 10 kVA generator could handle a load of 10 kw, or one of 10 kva, or a combined load of 8 kw and 6 kva, which would combine by the pythagorean rule to a load of 10 kva. In this latter case, however, the generator would need only an 8 kw turbine to drive it. If there are one kw of resistive losses of one kw, the 10 kw generator could deliver only 7 kw of power load, plus the 6 kva to the pure inductive load. This latter load could be thought of as an electromagnet which draws power from the system to store in its magnetic field during alternate quarter-cycles, returning the power to the system by collapse of the magnetic field during the remaining quarter-cycles. This flow of energy back and forth accomplishes no useful work but loads the generator and adds to the resistive losses in the network.

To see how an increment in kVA affects the system, we can differentiate equation (1) partially, keeping kw constant, to get 2 KVA/(KVAR) = 2 KVA/(KVAR), or KVAR = KVAR/2 = \sin \theta, where z is the phase angle by which the current drawn at the node lags behind the voltage. Cos \theta = kW/KVAR is what is termed the "power factor." And just as marginal cost is calculated in terms of kilowatt-hours for the power component, the marginal cost of the "wattless" component is to be calculated in terms of reactive kilovolt-amperes-hours, or kvarh.

It is immediately apparent that if the system power factor is 100 percent, so that \theta = 0, \sin \theta = 0, then additional kvarh will not increase either the kva or the kw in the supply to the node at all, and the marginal cost of kvarh will be zero. Thus, for system nodes where power factor is close to 100 percent, which would be the case for a location serving primarily lighting and heating loads, there is no justifica-
tion for charging customers for the use of a small quantity of reactive power even though their own power factor might be extremely low, aside from a possible small charge for a higher capacity service drop, if this were needed.

Where system power factor is substantially below 100 per-
cent, if the system is operating below capacity, it is to be noted that the impact of kvarh on system costs is limited to its impact on resistive losses, which vary as the square of the load. If the system is operating much below capacity, these costs will accordingly be small. Indeed, they are likely to be so small as to make charging for low power factor during off-peak hours not worthwhile.

The above considerations lead to the following conclusions as to the proper methods of charging for low power factor. (1) No attempt should be made to charge for low power factor unless the system is operating at low power factor and close to capacity. (2) If a charge is made it should be on the basis of kvarh drawn during peak hours, without reference to the power factor of the individual customer. The kvarh drawn by a customer at 98 percent power factor is just as much a burden on the system as one drawn by a neighbor who happens to be at 65 percent power factor. (3) While allowing for low power factor by calculating demand charges in terms of kva does tend to limit the charge for low power factor to peak hours, it does result in a separate kva meter, the cost of which would be better devoted to a measurement of peak kvarh, which is more closely related to cost.

Proper pricing of peak kvarh would help promote an ef-
cient allocation of capacitors and other power factor correc-
tion devices between customers and the utility.

Nonprice Financing

It is a commonplace of neoclassical economics, although seldom acknowledged by practitioners in the privately owned public utility field, that the marginal cost pricing required
to secure optimal allocation of resources will require some funding from sources other than the prices charged at the various margins. Before giving up and insisting that marginal cost pricing must be modified to take account of the distorting effects of taxes raised to finance a subsidy, it is appropriate to consider some sources of savings that are usually over-looked. Two of these are particularly suitable for financing locally oriented utility services that are closely attached to the metropolitan community. One is a tax on the land values that can be enhanced by the availability of local utility services at prices reduced to a marginal cost level. Another is a charge for the use of congested city streets that would raise the cost of such use to a level more nearly representative of marginal social cost. It seems at least possible that these limited facilities are utilized, thus costing the payors less, on balance, than the revenue collected.

Financing by Land Value Taxes

A theorem of spatial economics states that in a system of perfect competition among cities, the availability in the city of services and products subject to economies of scale, priced at their respective marginal social costs, will generate land rents just sufficient to supply the subsidies required to permit prices to be lowered to marginal cost. Among the more important of these services are utility services, such as electric power, telephone, cable communications, water supply, mail collection and delivery, sewers and waste disposal, and local transit.

On a more intuitive level, one can note that a person who occupies land provided with such services will be requiring that they be provided past his property to serve others whether or not he himself uses them. The user of tennis courts located conveniently in a built-up area should no more be excused from contributing to the costs of carrying these services past the courts, even though no direct use is made, than an electric power, telephone, mail, or other services, than he should expect his auto dealer to cut the price of an automobile by the cost of the headlights and windshield wipers merely because he asserts he will never drive in bad weather. Tennis players will indeed pay a rent enhanced by the presence of these services and the consequent greater demand for the land for other purposes, but the rent will go to the landlord, not to the party benefiting for the price of the services to those who do use them will be too high for efficiency, unless indeed they are subsidized by other taxes that have their own distorting effects.

Another corollary of this theorem that it would be to the advantage of the landowners in the area, faute de mieux, to agree collectively to pay a tax based on their land values, in order to subsidize the various utility services to enable the prices to be set closer to marginal social cost. They could expect in the long run that this action would increase their rents by as much or more than the taxes. To be sure, they might do better by getting someone else to pull their chestnuts out of the fire, but they can do this only at considerable damage to the overall efficiency of the economy of the city, to say nothing of the inequity of such a parasitic relationship.

In the case of telephone service, if the cost of the local distribution networks had been financed out of land-value taxes, the cost could be reduced by providing for the division of services from other payments from long distance charges would have been much weaker, or even of negligible weight. If long distance charges had been freed from the burden of this cross-subsidy, it seems at least possible that the remaining economies of scale in the long distance service would have been sufficient to allow the Bell System to reduce long distance rates to a level closer to marginal cost, thereby increasing efficiency, keeping its competitors at bay, and avoiding the disorderly mess that has resulted. There would have been less need to maintain a de jure monopoly, so that pressure from potential competition might have led to a more flexible service offering.

Financing by Congestion Charges

Another possible financing source for the utility infrastructure would be to levy appropriate charges for the use of the streets and road facilities at congested times and places so as to increase efficiency by bringing home to users the costs their use directly imposes on others. One method, proposed long ago as 1959 and currently in the process of being implemented in Hong Kong, is to require all vehicles using the congested facilities to be equipped with electronic response units. These will permit individual vehicles to be identified as they pass scanning stations suitably distributed within and around the congested area; the records thus generated can be processed by computer and appropriate bills sent to the registered owners at convenient intervals. If properly done, this would greatly improve traffic conditions so that the net cost of the convenience to the road users would be less than the amount collected as revenue.

Indeed, one can define "hypercongestion" as a condition in which so many cars are attempting to move in a given area that fewer vehicle miles of travel are being accomplished and travel time would be if fewer vehicles were in the area but could move more rapidly; for example, if 1,000 vehicles in an area move at 8 mph and produce 8,000 vehicle miles of travel per hour, reducing the number of cars in the area to a given time to 800 might raise speeds to 11 mph, producing 8,800 vehicle miles of travel per hour. By restricting the flow of traffic in the period leading up to a threat of hypercongestion, road pricing
Second-best Pricing

But whether or not land taxes or congestion charges are conceptually or legally dedicated to the financing of utility services, marginal changes in the amount of nonprice financing of utility services may have to be, and rationally should be, regarded as being financed by changes in other forms of taxation that have adverse effects on the allocation of resources. Under these circumstances it will generally be advantageous to raise utility charges somewhat above marginal cost in order to use the added revenues to abate the undesirable side-effects of these other sources of revenue. Indeed, one can regard the excess of utility charges over marginal cost as equivalent to a tax and compare the excess burden of this tax on utility services with that of other taxes. If we put $e$ for the elasticity of demand and $r$ for the ratio of marginal cost of a utility service at a given place and time to the price charged, then the cost to the customers of raising the net revenues from the utility operation by one dollar can be given by:

$$C = 1/(1 + er - e)$$  \hspace{5cm} (2)

If the price equals marginal cost, $r = 1$, and $C = 1$; also, if demand is totally unresponsive to price changes, $e = 0$, and $C = 1$, again. In these extreme cases raising prices does transfer revenues from customers to the operating authority without excess burden.

In normal circumstances, however, $C$ will be greater than one, and an efficiency maximum will be reached if $C$ has the same value for all rate categories and all taxes. In more realistic than another, it would be possible to get the same overall net revenue at lower cost in lost efficiency by getting more revenue from the situation with the lower $C$ and less from that with the higher $C$. Indeed, equation (4) can be formulated as:

$$(1-r)e = 1 -1/C, \quad (P - MC)/P = k/e$$  \hspace{5cm} (3)

where $k = 1 -1/C$, $P$ is price, and $MC$ is marginal cost. This is the "inverse elasticity" version of the rule first developed by Frank Ramsey in 1927. This version ignores interrelations between different services or services at different times.

A version that allows for such relationships in terms perhaps more appealing to the intuition has been developed by Bernard Sobin for use in conjunction with postal rates, based on the concept of the "leakage ratio." This is the percentage by which the net revenue realized as a result of a small increase in given price falls short of the amount that would be realized if there were no change in demand as a result. This latter amount is simply the product of the price increase and the amount of service to which it applies. The leakage is the
algebraic sum of the products of the change in the quantity of the various services sold and the differences between their respective prices and marginal costs. In the absence of externalities, this leakage is a measure of the loss of efficiency produced by the increase in price. An optimum balance is obtained when the leakage ratios are the same for all potential price changes.

Subsidy and Managerial Incentives

Whether the operation of the utility is nominally private or public, subsidizing the operation tends to impair the independence of the management and to divert managerial energies from economical operation to securing a larger subsidy. The destructiveness of maintaining financial independence may be sufficient to overcome considerations of the potential gains in efficiency through subsidization, especially if the overall elasticity of demand is considered slight or the economies of scale small. This would mean that the second-best pricing rules would be applied over the utility itself and not extended to equate the marginal cost of net revenues between the utility and the fisc. Yet the gains from subsidy may be so great or the degree to which conscientious management can be relied upon to consider the overall public welfare rather than the aggrandizement of its fiefdom may be such as to warrant an attempt to extend the equalization of the marginal cost of net revenues over the entire public sector. In practice this might involve some estimate of the particular tax or taxation that would be altered to provide the alteration in the subsidy.

Local transit in modern industrial economies seems to derive such substantial benefits from subsidy that subsidized operation is nearly everywhere the rule outside developing countries where labor costs are low. For other utilities the picture is more mixed. In the United States, private, regulated, unsubsidized operations predominate, while elsewhere utilities are mostly publicly owned and often subsidized.

Some compromise may be possible where the financial autonomy of the utility operator is maintained, at least in the short run, by establishing the rule by which the subsidy is to be determined in as unalterable a way as possible. The formula could involve such parameters as capital charges, an index of service units provided, weighted by marginal cost, or by a base period set of prices. It is difficult to devise a formula that will be entirely free of distorting influences, but with care such influence may be minimized. Generally, subsidy based on output seems preferable to subsidy based on cost. Some movement in the direction of an exogenously determined subsidy may be attainable through capping the subsidy in terms of exemption from specific taxes.

The Pricing of Reservation Services

In many cases a constantly changing and volatile set of customers make fairly strong commitments to the use of a service at a specific future time, as with airline reservations. To enable customers to make efficient decisions at the time they make their commitment, it is necessary to quote a price representing an estimate of the expected marginal cost as of that moment. The major element in this marginal cost will be the cost of displacing someone else from a seat. If all the seats are empty and no one is displaced, the cost is limited to the minor costs of extra wear and tear, fuel, and personal services, plus possible inconvenience to an adjacent passenger. By appealing to the perfectly competitive market concept, we could imagine reservations being sold by retailers trading in a perfectly organized and costless market in a manner analogous to commodity futures, in which speculators are distinguished from customers so that at any one time the number of seats on any given flight remaining to be sold by the speculators is known. Price at any given time would be the price at which if maintained until departure would be expected on the average to just sell the remaining seats. Sale of a seat at a given time would lead to a slight increase in the price over the remaining period sufficient to reduce demand by one seat; the price of the seat taken would correspond to the expected value of the seat given up.

An actual speculators market would be too expensive in terms of the profits exacted by the speculators, and the costs of a trading mechanism such as that used for the very large commodity futures contracts would be excessive for even the more expensive airline flights. It would not be difficult for an airline to estimate the results of such a market by establishing a schedule giving the price for a given flight in terms of the proportion of seats already sold and the time remaining to departure. Whenever the sale of seats runs ahead of the normal pattern, the price would be increased (the converse when sales lag) in such a way that it would be extremely rare for a last-minute passenger not to be able to get a seat, albeit possibly at a very high price. Planes would be nearly full most of the time, and for those not full, seats would have been offered at very low prices for a substantial time before departure.

A formulation more in line with conventional pricing practice would be to divide seats into blocks with a range of initial prices for the various blocks and have the price for any given block decline over time, somewhat in the manner of a "Filene basement" scheme. At any given time sales would proceed from the cheapest block until it is sold out.

Such a pricing method would, of course, be worthwhile only if the unit of sale is substantial enough to make the costs of the procedure worthwhile. One could, in theory, envision a
comparable method applied to the sale of newspapers: the price at any given outlet would vary over the day according to the number remaining unsold in relation to the time of day. Ideally, the results would be that a sold-out condition would be fairly rare, while the number of returns would be small. In practice, however, one could not expect results to come very close to this ideal, given the relatively low price elasticity of demand.

**Summary**

There are thus major improvements in efficiency to be obtained by pricing in closer relation to marginal social cost. Achieving these efficiencies, however, will at many points require very substantial deviation from the conventional forms of pricing that have developed over the years.

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**A CRITIQUE OF RAMSEY PRICING**

Douglas Pegay and Kenneth Nowotny

During 1985, in exchanges with regulators and the regulated from one end of the country to the other, we sensed a great raging and gnashing of teeth. The social contract implicit in the Hepburn Act of 1906 seems to have come unstuck. Producers which formerly were monopolies over virtually all their potential customers have found that, in general, this is no longer so. The word by-pass has replaced the less accurate concept, cream-skimming.

By-pass affects virtually all public utility industries: electricity, communications, natural gas. The situation has come about due to changes in technology, relative prices, and institutional rules. But irrespective of the source, by-pass poses considerable problems for public utility regulation, problems for which traditional tools and structures were not designed. The search, then, must be for new tools and new regulatory structures to deal with the world as it is, not as we wish it to be.

This paper addresses pricing problems created by the new environment in which the public utility finds itself. In short, utilities are faced with losing substantial loads, leaving fixed costs to be spread across a smaller amount of output. To prevent customers from leaving the system, prices must be lowered; if the system contracts, perhaps prices must be raised to the remaining customers. Price discrimination may be essential to maintain the integrity of these systems, but how can it reasonably be approached?

The first section of this paper discusses some recent structural changes in the public utility industry. The second presents the Ramsey pricing approach and some formal criticisms.
of it. The third section discusses difficulties with implementing Ramsey pricing in a practical context and the implications of doing so. Finally, some reasonable rules for price discrimination are offered for these trying times.

Recent Structural Changes

The 1970s, needless to say, were a period of substantial economic and technological change. We saw a dramatic rise in the price of fossil fuels relative to other commodities. Technological innovations in circuit miniaturization, begun in the 1950s and 1960s, came to fruition in the marketplace. For electrics, the age of exploiting scale economies was approaching an end, and these power producers were facing new challenges from environmentalists, conservationists, and consumer advocates.

AT&T weathered the 1960s with the Carterfone and MCI-I decisions to be faced with MCI-II and another antitrust suit. The rules of the game were changing at the same time that the playing field was undergoing massive alterations. Pipelines and gas producers were facing increased demand when more gas could be had only at a cost higher than allowed by the FPC (FERC). In Texas, gas was $1.50/mcf, in the rest of the nation four bits. Before, during, and after NGPA, gas pipelines and LDCs were entering into take-or-pay contracts to assure themselves and their customers of a supply of gas. No one in the industry predicted that OPEC the tiger would become a pussycat by 1983 or 1984.

For the electrics, PURPA brought the problem of cogenerators, a subtler and less invasive but no less important form of by-pass. But with or without PURPA, cogeneration would have come. Rapidly escalating prices for electricity and the expectation of scale economies meant that some large consumers of electricity, particularly those with process, residual heat, might more economically produce their own electricity, particularly if regulatory rules required utilities to buy the cogenerators' excess. In effect, the utility was required to provide cogenerators with an 80-90 percent load factor while reducing its own by losing the cogenerator's load. Research in the 1970s led to a growing interest in solar-photovoltaics, active and passive solar heating, structural insulation and orientation, all of which were to rob the utility of load and worsen its load factor. Solar research has thus far tended to reduce winter heating loads without significantly affecting summer cooling loads. After a disastrous, the Bell Operating Companies complain that they are not on a level playing field. The interLATA carriers are allowed virtual free rein in competing for markets, and the BOCs are hobbled by certification and pricing restrictions. Cable and wireless, the Bell voice systems, take away local exchange customers, and even the intralATA long distance market does not appear to be completely safe for the BOCs.

In New Mexico, mandatory contract carriage is a fact of life for gas pipelines. EPNG and PGB appear to be in a very serious struggle with diesel fuel in California markets as well as with Canadian gas distributors. The falling price of oil from pascagoula OPEC has opened a new source of problems for the pipelines and LDCs, already struggling with take-or-pay contracts with suppliers.

The electrics watch, sometimes with glee, the fate of their new nemesis, the gas suppliers. Certainly, however, the electrics must wonder whether mandatory wheeling can be far away. Requirements of wheeling will mean the same financial hardship from loss of markets for the electrics that contract carriage may mean for the pipelines.

Considering all this, utility companies today might look more benignly on the 1935 Motor Carrier Act. In effect, a new technology combined with federal and state government activity in the building of an interstate highway system confronted the railroads with precisely the same problem being faced by the utilities. The federal response, and that of many states as well, was to regulate trucks and buses. 20-20 hindsight tells us that that was exactly the wrong thing to do, but we need to translate that observation into constructive responses for current problems.

The utility built plant and equipment to serve two sets of customers jointly. Each set benefited by the existence of the other as a result of lower average fixed costs. Utility regulators engaged in the mythology of allocating costs as between these two sets of customers. The allocation nonsense allowed some to talk persuasively about one set subsidizing the other.

Admitting the arbitrariness of interclass cost allocations did not prevent advocates from maintaining that long distance service subsidized local service in the telephone industry, or that industrial customers subsidized residential, or vice versa, in the electric and gas industries. But cost allocations allowed utilities and regulators to practice price discrimination based on accounting shenanigans, as the enabling legislation required. They practiced price discrimination largely because it was necessary to do so, and generally it was done in a reasonable fashion. Price elasticities and price differentials were not so large as to be undendurable for the less elastic set, partly because the more elastic set had not many more alternatives in any event. Political reality prevented the excessive abuse of price discrimination. In the 1950s and 1960s, no one much cared since prices were low and falling. The 1970s brought these practices under greater scrutiny, as prices began to rise precipitously, but there was no great panic; as indicated, differentials were usually modest and as often served the less elastic group as exploited it.
Now the tide has turned. The more elastic set has evidently a great variety of alternatives. The plant built to serve the two sets of customers must be paid for if the more elastic set abandons the system. The only way to keep the more elastic set on the system is to lower its price sufficiently to make it worthwhile to stay. The current notion is that the resulting price should be adequate to yield a contribution to overhead or the remaining group will be indifferent to the presence or absence of the other. This is not strictly true, but close enough.

The question, then, for economists is: Does economics have anything to offer this discussion which will clarify the issues rather than obscure them? We try to answer here with a categorical yes.

What Is Ramsey Pricing?

Marginal cost pricing has long been the economist's criterion for social efficiency. Dialogue concerning the value of marginal cost pricing has been based on the work of Dupuit (1932), Hotelling (1938), and more recently Ruggles (1949). The price equals marginal cost solution is shown to be the first-best (or unconstrained) welfare maximization rule. The problem of applying the marginal cost principle to public utilities is that the technology used by many of these firms is such that the average cost of service may be falling over the relevant range of demand. In such a situation, marginal cost will be less than average cost. Therefore, a strict adherence to the marginal cost pricing rule will result in operating deficits. The question posed to economists is how social welfare can be maximized, given that the public utility is allowed to cover its costs.

Essentially, two methods have been suggested for dealing with the potential deficit. First, prices may remain equal to marginal cost, and the resulting deficit is covered through subsidies generated from an external source. Hotelling suggests that if these subsidies are paid through lump-sum taxes, no wedge will be driven between prices faced by consumers and those received by producers; thus, no distortions will enter the economy. Moreover, Hotelling continues, although the distribution of income would be affected by such a scheme, the total level of income would be left unaffected. With the redistribution, if the net gainers of well-being outweigh the net losers, there is the potential for the losers to be compensated. Of course, this analysis requires either an interpersonal comparison of utility (if a compensation scheme is not available) or that a viable compensation scheme actually exists. Furthermore, one of the taxes suggested by Hotelling was the income tax, which is not a lump-sum type.

If deficits from marginal cost pricing are not to be covered by external funds, then the average level of rates must be raised to the level of average cost. Satisfaction of this "budget constraint" necessitates some departure from the optimal (first-best) marginal cost pricing rule. Accepting the budget constraint as a requirement, one may ask whether the second-best pricing rule—the rate structure that introduces the least inefficiency while still allowing the utility to cover all its costs—A similar problem was originally tackled by Franklin Ramsey (1927): "If a given revenue is to be raised by proportionate taxes on some or all uses of income, the taxes on different uses being possibly at different rates; how should these rates be adjusted in order that the decrement of utility be a minimum?" His second-best solution, the so-called Ramsey rule, was that gross prices (prices including the tax) should be increased the least for those services that have the most elastic demand and the most for those with the least elastic demand.

Baumol and Bradford (1970) applied Ramsey's problem to the case of the multiproduct (for example, different customer classes) natural monopolist. Their work shows, perhaps most clearly, how the Ramsey rule is derived and some of its implications for social efficiency. A rough sketch of the calculus is given here for a consumers' surplus definition of welfare. Although Baumol and Bradford assert that the social welfare function maximized in their paper is unspecified, Mohring (1970) demonstrates that this "unspecified utility function actually had the properties of the consumers' surplus measure." Therefore, it is felt here that such a measure of welfare is representative of the work done by Baumol and Bradford.

Let the natural monopolist supply n customer classes, and let the inverse demand curve and measure of consumers' surplus for the ith customer class be represented by equations (1) and (2), respectively.

\[ p_i(w) \]  
\[ S_i = \int \frac{p_i(w)}{w} dw = \pi_i(w) w \]  
\[ * \]

The problem is how to minimize the losses in welfare, W, due to the firm charging prices (for each customer class) above the respective marginal cost of serving each class. This problem can be alternatively stated as:

\[ \max_{w} W = \sum_{i=1}^{n} S_i (i = 1, \ldots, n) \]  
\[ * \]
subject to the constraint that
\[ \sum_{i=1}^{n} P_i(Y_i)X_i = c(Y_1, \ldots, Y_n), \]  
(4)

where the left-hand side of (4) is merely the total revenue generated from all the customer classes, and the right-hand side is the total cost of serving all customer classes.

From the first-order conditions of this constrained optimization problem we can derive the following results:
\[ \left( \frac{P_i - MC_i}{P_i} \right) \xi_i = \frac{1 - \lambda}{\lambda} X_i = 1, \ldots, n, \]  
(5)

where \( \lambda \) is the Lagrangian multiplier, and \( \xi \) is the demand elasticity of the ith customer class. Therefore, for any two customer classes, i and j,
\[ \left( \frac{P_i - MC_i}{P_i} \right) E_i = \left( \frac{P_j - MC_j}{P_j} \right) E_j, \]  
(6)

where \( E \) denotes demand elasticity in absolute value. Note that (6) is the Ramsey rule. If, for example, \( E_i > E_j \), then for (6) to be maintained as an equality, it must be the case that \( P_i - MC_i < P_j - MC_j \). In other words, class i receives a price closer to marginal cost than does class j.

Finally, (5) can be rewritten to yield the following approximation:
\[ \Delta Y_i = \frac{1 - \lambda}{\lambda} \frac{\Delta Y_i}{Y_i} = 1, \ldots, n, \]  
(7)

where the left-hand side of (7) represents the percentage change in service to class i (a decrease) resulting from the class receiving a price higher than its respective marginal cost (that is \( P_i = MC_i + \Delta P_i \)). This is shown in Figure 1.1, where \( D_i \) represents the demand curve for this customer class. For illustrative simplicity marginal cost is assumed to be constant.

For two different customer classes, i and j, (7) implies that
\[ \frac{\Delta Y_i}{Y_i} = \frac{\Delta Y_j}{Y_j}, \]  
(8)

or that social welfare is maximized, subject to the revenue constraint (4), by charging prices \( P_i \) and \( P_j \) such that the percentage decrease in output is the same for the two customer classes. This is shown in Figure 1.2. Here, the demand curves for customer class i and j are given by the lines \( D_i \) and \( D_j \), respectively. Again for illustrative simplicity the marginal costs of serving the two customer classes are both equal to the constant MC, with the first-best (P = MC) level of output identical for both. In Figure 1.2 it is clear that the demand curve of customer class j is less elastic than that of customer class i. In order for the percentage change in output to be the same for the two classes, the figure shows that the price increase above marginal cost for j, \( P_j' \), will have to be greater than that for class i, \( P_i' \).

Essentially, then, the Ramsey rule maximizes welfare subject to the revenue constraint by choosing the set of prices \( P_i = 1, \ldots, n \) such that distortions in output are minimized.

The role of relative demand elasticities across the different customer classes is crucial. Here, the optimal second-best solution is reached when the relative price deviation from marginal cost for each customer class is inversely proportional to the elasticity of demand. A large deviation from marginal cost is applied to the customer class for which there would be little change in demand—resulting in a small distortion from the first-best consumption amount, yet generating a significant addition to revenue; the customer class that is most sensitive to price receives the smallest mark-up, and therefore a large reduction in the optimal consumption amount is avoided.

The Ramsey rule can be viewed from another and more relevant perspective. If all prices are equated to average total costs, satisfying equation (5) would imply that prices would rise in the inelastic demand markets and fall in the elastic demand markets (Baumol 1967). With respect to the implications of this type of price discrimination, Kahn (1970, p. 144) concludes: "Following such a rule would have the effect of favoring the [elastic demand] customers over the [inelastic demand] customers [representing] a decision to distribute the major part of the benefits of the increasing returns to the [elastic demand] customers. Such an action could be justified on the ground that, since the surplus or welfare gain that the [elastic demand] customers obtain...exceeds what the [inelastic demand] customers lose, the former could compensate the latter. But without any arrangements for such compensation, this discriminatory pricing pattern would in effect distribute more income to the [elastic demand] than to the [inelastic demand] group."

If no compensation schemes are available, economics cannot provide an unambiguous statement with respect to the "efficiency" of redistributing income. The increase in utility from a dollar gained by an elastic demand customer cannot be compared to the decrease in utility from a dollar lost by an inelastic demand customer, except merely to observe that compensation would be possible. Even if, by some calculation, economists as a group decided that a dollar is worth the same to both groups, Kahn (1970, p. 145) asks a more fundamental question:..."
question: "By what right do we as economists decide it is proper to transfer income from one group to another?"

One might ask under what conditions does there exist an arrangement for the "gainers" to compensate the "losers." Zajac (1978) gives two examples in which such compensation will take place, both highly idealized. In the first case, all customer classes are comprised of the same set of individuals, the losers and gainers are the same people, and income is merely shifted from one pocket to the next.

At the other extreme, suppose that a utility has only two distinct customer classes: residential and a single industry. Moreover, assume that this single industry (say, bread) is highly competitive and sells its output only to the utility's residential customers. The utility moves to Ramsey prices and the industrial customers receive the lower electric rate; this "gain" will show up in a lower price of bread. Thus, the residential customers would be compensated indirectly by purchasing bread at the lower price.

Aside from these two idealized situations, compensation can only take place if the regulatory body has at its disposal some legal mechanism which would allow it to arrange for the "gainers" to compensate the "losers." Unfortunately, as Zajac (1978, p. 46) points out, such instruments for compensation are "rarely feasible, so that a pricing reform that goes from existing prices to economically efficient prices is bound to incur the wrath of those whose prices are increased.... Put in other terms, the regulator or policy maker must operate with the instruments available to him and in terms of the political institutional constraints that he faces. The instruments will rarely provide for direct compensation or lump sum transfers from one group to another."

A related issue is one of attaining "noneconomic" goals. A regulatory body may acknowledge that existing prices are inefficient and that welfare would increase (that is, deadweight losses be eliminated) by moving to a set of Ramsey prices. As Zajac emphasizes, however, "economic or allocative efficiency is not necessarily economic justice." Specifically, economic efficiency is defined for a given distribution of income. If that distribution is, by some equity criterion, considered unjust, then a move toward greater economic efficiency (in the Pareto sense) may still be unjust—even if a compensation scheme exists.

As economists it may be intellectually appealing to divide the world into two mutually exclusive sets: one comprised of efficiency problems and the other comprised of equity problems. If we accept this division, we may indeed feel comfortable with giving advice on efficiency goals while letting others grapple with problems of justice. Zajac (1978, p. 52) remarks: "Although this separation-of-problems viewpoint may have some merit when theorizing about a pure market economy, it is difficult to accept in theories of regulatory pricing."
Based on an economic concept of costs.

Ramsey Pricing in the Face of Competition

Up to this point, the discussion on Ramsey pricing has assumed that the natural monopoly is completely immune from competition. Increasingly, this is not the case. Either direct entry (or potential entry) by rivals into some of the regulated firm's markets or the growth of competition from different modes of service will affect the determination of efficient prices.

Braeutigam (1979) sets up a model in which there is one regulated firm (the natural monopoly exhibiting falling average costs) and a number of different modes of service such as operating under competitive conditions. He gives railroads offering freight transportation services as examples of falling average costs and offers other industries, such as motor and water carriers, as examples of different modes providing essentially the same service.

With the addition of other modes of service, the demand elasticities for each customer class facing the regulated firm will be affected. Moreover, when Braeutigam sets up a welfare maximization problem similar to the one above, except with the inclusion of these new rivals, he gets an interesting variation of the Ramsey rule. Specifically, from the perspective of the regulated firm, the second-best pricing solution (the difference between price and marginal cost being inversely related to the elasticity of demand) is now optimal only if such a pricing rule is also being adhered to in the other (competitive) industries.

Looking at another way, if the competitive nature of the rival firms drives price down to marginal cost in these other industries, then the set of Ramsey prices being charged by the regulated firm is no longer optimal. The implications of Braeutigam's result is that in order to ensure allocative efficiency the regulatory body would also have to regulate the rival firms. Efficient prices on the part of the regulated firm would require that the rivals also charge a price above marginal cost. This would require that the regulatory body either restrict entry into the other industries or impose a set of taxes to ensure prices consumers pay diverge from the marginal cost of serving them.

Indeed, expanding the regulatory body's jurisdiction in this manner would represent an enormous undertaking. Moreover, as Braeutigam points out, "under the present statutory powers, regulators are not empowered to impose taxes, even if they had sufficient information to determine the levels of the taxes required." Looked at from the theoretical extreme, unless the regulatory body is allowed to restrict entry into all industries which affect the demand elasticities of the natural
monopoly, Ramsey prices will no longer be optimal.

Under certain conditions (see Zajac 1978) if compensation is feasible from the gainers to the losers of the regulated firm's Ramsey pricing structure, there would be little incentive for customers to purchase the service from the regulated firm's rivals. The problem, of course, occurs when a mechanism for compensation is unavailable. In this situation, an individual customer class may find it cheaper to purchase the service from one of the regulated firm's rivals, although the total resource costs to society might be lower if all customer classes purchased the service from the monopoly. Here, the set of Ramsey prices (without compensation) is said to be unsustainable or vulnerable to attack by a rival.

Zajac points out another instance of vulnerability which is possible even if compensation is available. He calls it game-theoretic instability. Consider a hypothetical list of costs facing a regulated monopoly which serves three different categories of customers. Let $30, $48, and $75 refer, respectively, to the costs of serving one, two, and three classes jointly. Note that it is cheaper to provide any combination of services jointly rather than separately (subadditivity of costs prevails). For illustrative simplicity, assume that the same cost structure would apply to any potential rival.

Suppose that the regulated firm is to serve all three customer classes jointly and that the costs are allocated equally across the three classes ($25 each). Eventually, two of the three classes will have only two classes (say, class one and two) and would discover that as a group they are paying $50, but if some rival firm supplied them with the service they would, as a group, be paying only $48. As a result, class one and two would agree to be served by the regulated firm only if they were charged, say, $24 each. This, however, would mean that class three would have to be charged $27. Now, class three and either one or two will discover that as a group they are paying $51, but if some rival firm supplied them with the service they would, as a group, be paying only $48.

Zajac proves that no matter how the $75 overall required revenue (the cost of the regulated firm serving all three customer classes) is apportioned among the three classes, it would always be the case that some two classes are contributing in excess of $48. Therefore, they would have an incentive to purchase the service from a rival firm. Finally, Zajac points out that the notion of "gainers" compensating "losers" simply means a change from one possible apportionment of total costs to another. Therefore, under some circumstances, even if compensation is available, Ramsey prices would be unsustainable.

What makes the above list of costs ($30, $48, $75) "unstable" is that even though average total costs are falling throughout, the incremental costs of serving an additional customer class fall from zero to two but then rise from two to three. If incremental costs were also to fall throughout (if the list of total costs was $30, $55, $75), then the game-theoretic instability observed above would not exist.

In this section, we have attempted to demonstrate that the optimality claims for Ramsey pricing depend on some highly limiting assumptions and a fairly restrictive world view. Even granting the necessary assumptions and accepting that world view, the application of Ramsey pricing to public utilities in the presence of intermodal competition leads to the need to review completely the nature of capital valuation. This topic is considered next.

The Bogus Revenue Constraint

The process as currently constituted allows utility firms to recover current costs and embedded capital. It is obvious that the heart of the problem is the latter. The marketplace provides that a firm's value is a function of what it can earn in the marketplace, but what a utility firm may earn is established by regulation. The Supreme Court recognized the circularity of this process in the Hope decision many years ago.

Fundamentally,

\[ \text{Value} = (PQ-C)-1. \]

The regulatory process, however, takes

\[ \text{Value} = \text{Book Cost} \]

and then finds

\[ P = \left[C + (\text{Book Cost})r\right]-1, \]

where

\[ r = \text{div/share} + \text{growth rate of earnings}. \]

\[ \text{price/share} \]

Of course, dividends/share is a function of P, Q, C, Book Cost, and r. Moreover, C is a function of Q, and Q is a function of P. In effect, then,

\[ P = p (P, \text{Book Cost}). \]

In a competitive market, the marketplace establishes parameters around the price of a good or service. This price then establishes output, revenues, costs, and therefore the value of the firm's investment. The firm makes a profit, loses money, or goes out of business, in which case the value of the
investment is the scrap value of plant and equipment.

Suppose a gentleman runs the only bar in Kinchloe, Michigan. He sells whiskey to two sets of customers. Air Force personnel and woodcutters. Suppose he sells the bar to a young lady for $100,000 on the basis of its monopoly position over the consuming habits of the two sets of customers. Suppose that, sometime later, the Air Force closes its base at Kinchloe. The bar still has a monopoly over the consumption of the woodcutters, but is the bar worth $100,000? Can the lady raise prices to the woodcutters sufficient to make her earn what she paid for the bar? This was the question that was expected when she bought it.

In effect, given expected revenues, utilities have purchased plant and equipment to service two sets of customers. In the extreme situation, they may be left with only one. Would only a utility have built the same system if there been only the remaining set of customers in the first instance? Would our hypothetical barkeep have paid the $100,000 knowing she could sell booze only to the woodcutters?

But the utility can say that we were never allowed to earn monopoly profits in the first place. Of course not, and the lady could not have earned monopoly profits either, since she was bidding for a bar whose owner knew it was a monopoly. He received the Marshallan rents in the sale price. She could earn only a normal return.

But the utility can say its monopoly has not been protected, which was part of the bargain. Of course, that was part of the bargain, when conditions warranted the existence of the monopoly. Things have changed in a more or less unforeseen fashion. And it is true that divergent 

judge's rules, mandatory contract carriage, PURPA, and other legislative and regulatory mandates have resulted in new conditions imposed upon the status quo. But what we are to answer is how one goes about pricing in today's environment, not the one we might wish for.

In today's environment, the value of plant and equipment purchased by utilities may not be worth, in economic values, what was paid for it. Precisely because there is no monopoly over all their customers or potential customers.

The Ramsey-pricing model is one means for determining discriminatory prices in the face of fixed economic costs, not bookkeeping marginal costs.

To illustrate, let us return for a moment to Kinchloe, Michigan. Suppose, instead of the Air Force base closing, the problem facing our bar owner is that the base builds an NCO club that runs perpetual happy hour. The woodcutters never come to the town bar except late in the evening. The only solution is obvious. Although our lady may protest to the Air Force about undue competition from a subsidized facility, it will probably do no good. To maintain her Air Force clientele, she must approximate the NCO club prices. She may charge slightly more due to the ambiance of her bar but not much more.

Suppose this price is sufficient to pay the help's wages and the out-of-pocket costs of whiskey and dishwashing.

Once again, she is faced with the problem of meeting her overhead from the sale of whiskey to woodcutters. Is her bar worth $100,000? She can charge a price to woodcutters no higher than what they would be willing to pay to go to a saloon at the corner of Main and 30 miles away. To buy by the bottle and carry the liquor back to Kinchloe. Needless to say, that will be greater than the happy hour price at the NCO, but it will not yield a normal rate of return on a $100,000 investment. Her bar is not worth what she paid for it.

What we are saying is that price discrimination must consider the economic worth of the investment in computing revenue requirements. Any price discrimination scheme that excludes the face value cost is not optimal in any sense. The only question is: What are the potential economic options for the inelastic customers?

Back Door Revenue Requirements

In considering the use of the Ramsey rule, it should now be obvious that at issue are economic values, not accounting values. The applications of accounting costs, historical or reproduction, will lead to irrelevant deviations from marginal cost and, thereby, an inefficient allocation of resources by any standard of fairness. If one is going to implement the Ramsey rule, the appropriate price is one which considers all ownership and cross-price elasticities and a revenue requirement which measures the economic value of capital to the marketplace, not the accountant.

Historically, reasonable price discrimination has meant that the most price-elastic customer would face a price at least a minimum, no less than incremental cost, while the least price-elastic customers faced a price no greater than what would obtain from a stand-alone system. In general, this was not a bad rule when disparities were small, that is, the most price-elastic customers had few genuine alternatives. But in the face of significant intermodal competition, the old rules will not work. They will not work precisely because intermodal competition means that a significant part of the firm's market is no longer served by a natural monopoly. The value of common facilities and scale economies have, simply, shrunk. The regulatory process has, fundamentally, two options: (1) the road taken by the Motor Carrier Act of 1935, that is, regulate the competition, or (2) a value utility plant devoted to common carriage.

It seems to us that history recommends the second alternative. We are unimpressed by the arguments that to do so opens up an entirely new adversarial procedure or that it is unfair to stockholders and (somewhat) ultimately harmful to customers. In 1942, Justice Jackson observed in the majority opinion in Wickard v. Filburn: "It is of the essence of regulation that"
it lays a restraining hand on the self-interest of the regulated and that advantages from the regulation commonly fall

to others" (pp. 124-25 and 129).

In the future, the first phase of a regulatory proceeding

should be to set the price which will be charged. From that,

consumption and expenses can be estimated. The difference

between revenues and direct expenses, including depreciation

of the plant, will yield a discounted stream of income that

indicates the economic value of plant devoted to the public.

That is, approximately,

\[ V^* = PQ - EX - d - Tx. \]

It requires little imagination to see that

Revenue Requirements (PQ) = EX + d + Tx + (V^*)\n
and the classic revenue requirements formula is fulfilled

automatically, having chosen P. The amount V^*, of course, has

nothing to do with the book cost of plant and equipment. This

last equation is what we refer to as the Back-Stop Revenue

Requirement.

A Theoretical Dilemma

The discussion of the Ramsey rule, by and large, leaves

the issue of the revenue constraint an open question. There is

no problem, of course, for MC greater than or equal to average

total cost, or at least no real problem for regulators. The

question arises when MC is a natural monopoly

in a long-run concept, not short-

that is, after all, the weakness of average fixed costs

cannot be a function of embedded costs.

The implicit Ramsey revenue constraint can only be one for a

firm in long-run equilibrium, that is, when plant is of an

optimal size. It is incumbent on regulators, then, considering

utility and price accordingly. The firm will adjust plant to

to that level, and/or the stockmarket will adjust firm valuation

Reasonable Rules

The socioeconomic problem in Ramsey pricing arises from

the disparity in opportunities available to classes of cus-

tomers, which arises from (1) the price of alternatives for

consumers, which arises from (2) the usage level of the price-

inelastic class, and (3) the income level of the price-inelas-

tic class. Of course, a combination of all three affects the

total price-elasticity of a class, as a rule.

In category (1) we might note that solar-photovoltaics

would be a reasonable alternative for the residential electric

customer, except that at $12,000 to $20,000 per kilowatt, even

a $2,500 per kw nuclear plant seems reasonable, irrespective of

the consumer’s income or usage. In category (2), the price of

diesel fuel or carriage gas is most certainly reasonable as

compared with the LDCs’ price, but the level of usage is, quite

likely, too small to justify the transaction cost of acquiring

carriage gas or the cost of a dual system furnace in which to

burn diesel fuel. Under category (3) we might observe that

given a sufficiently low priced alternative and an adequate

usage pattern, it is frequently necessary to make a substantial

capital outlay to enjoy the savings of lower operating expenses. For example, a solar hot water system initially may

require $1,000-$2,000, with hot water being virtually free

thereafter. Low income individuals may not have access to the

original financing, even though they could afford the mortgage

on the unit.

If the only viable alternative for a consumer comes under

category (1), then the best regulators can do for such a

consumer is to consider what the cost of an optimally scaled

system of the existing one would yield as a price. If there

are unused options under category (2), the regulator may decide to

ask what the price would be if inelastic consumers were able to

purchase cooperatively so as to reduce transaction costs

sufficiently. Under category (3) it should be obvious that if

regulation is in place to replicate competition, it is precisely

the price of such alternatives at which monopoly prices

should somehow be set. It is, after all, the weakness of consumers in

the market which is to be obviated by regulation.

This procedure may involve a transfer of welfare from

stockholders to consumers, or at least it may be perceived as

such. But if we go back to our bar in Kincheloe, consider the

situation in which the barkeep decides to charge the woodcut-

ters a price for libations sufficiently high to compensate for

the purchase price of the saloon. The woodcutters, of course,

get in their pick-ups and head for Sault Ste. Marie. Before

they leave town, however, they are stopped by the sheriff

and compelled to return to the local pub, where at gunpoint

they are forced to consume their usual quota and pay the new

price. This is quite obviously a transfer of wealth from

consumers to stockholders. How much different is the situation

when regulators protect a former monopoly utility, ignoring the

fact that the situation is one of disequilibrium in a context of

an income distribution which mitigates against a large

portion of the consuming public.

We are not, of course, advocating a substantial write-off

of utility assets, although it appears that AT&T and some BOCs
are scheduling some asset expensing over the next few years. We are not, of course, advocating price discrimination as a panacea for current utility problems; quite the contrary. What we are suggesting is that the advocates of Ramsey pricing have not told the whole story, that Ramsey pricing is not optimal in just any context, and that Ramsey pricing in the presence of booked accounting costs is regulatory approval of precisely that which, for example, the Act to Regulate Commerce was supposed to prevent. We are suggesting that, among other things, adoption of Ramsey pricing implies using an economic value of capital, absent monopoly power: in for a penny, in for a pound.

References


After reading the papers by Patrick Mann, Thomas Austin and John Stutz, William Vickrey, and Douglas Gagax and Kenneth Nowotny, I am not sure I detected any new issues in public utilities costing and pricing. Yet, one could say that nothing is new, depending on the time frame of reference. I viewed the four papers as follows: Two describe selection of methods for costing, one is a critique of an old but little used method, and one presents a new, radical costing and pricing approach.

None advocates a particular methodology or a particular pricing philosophy with great fervor. In discussing the papers, therefore, it seems best to analyze how they collectively can help regulated companies and regulators review costing and pricing in today's world. I will try to do this first by asking several questions and then offering some general comments.

Why do we care about cost of service anyway? We are concerned with efficiency in the use of utilities' services, especially those which consume scarce resources involving the use of water, the production of electricity, and the consumption of natural gas. We are also concerned with the availability of utility services, including the universal availability of telephone service and the availability of adequate supplies of natural gas and uninterrupted availability of electricity. Finally, we are concerned about equity. In this regard, Professor Bonbright noted that cost studies provide a useful "first approximation" of fair prices.

Q: Why are we more concerned about cost of service now than a decade or two ago? Higher prices fueled by inflation and scarcity in the 1970s and early 1980s make cost of service and pricing more important. Increasing political pressure, largely in reaction to increasing prices and scarcity, is evident in the natural gas deregulation process, PURPA in the electric industry, and in congressional oversight of the FCC in telecommunications. Finally, and probably most important, is the competitive entry recently being promoted for markets that were previously totally monopolistic. Entry is being permitted in electric, gas, and telecommunications markets, and this entry is providing the most powerful possible stimulus to determining costs and repricing services. Since not all markets of utility companies are open to competitive entry, there is the difficult regulatory problem of protecting inelastic markets from price gouging while at the same time permitting sufficient pricing flexibility in elastic markets to avoid unnecessary loss of business and contribution to joint and common corporate costs.

The usefulness of these papers, as I see it, is in the advice and counsel they offer to both regulator and regulated during this time of transition. In this regard, as I examine them I find that none professes to have found the "right" approach. They describe marginal methods and embedded methods, short-run methods and long-run methods of cost assignment. In addition, the Nowotny paper raises the possibility that pricing methods appropriate to today's environment need not cover accounting revenue requirements. This is a very important question, both for consumers and shareholders. Yet, if it is determined that pricing should match accounting revenue requirements, the question of how that is to be accomplished if marginal costs vary from book costs must be answered. Here we are given some advice on how to engage in "reasonable" price discrimination.

Before addressing some particular points in each of the papers I believe it is necessary to acknowledge that there are many possible variations in fully distributed and marginal costing methodologies, all of which are plausible in their mechanics and many of which are deemed reasonable in their results. We would all be naive, however, to believe that utilities with desires to retain market share in newly competitive markets will not be influenced to select costing methods which tend to shift the greatest proportion of costs to inelastic customers. This tendency is extensively discussed in the economic and regulatory literature. What we must balance against those tendencies and regulatory fears, however, is the clear possibility of doing consumers more harm in the long run by overprotecting inelastic customers from price increases in the short run. We have to look at our best estimate of the long run and make wise choices which will move prices in the right direction to bring about efficiency gains that the open
entry policy was designed to achieve in the first place.

The Austin/Stutz paper correctly points out that costing and pricing philosophies are determined largely by the regulatory and market environment in question. The examples are taken from the electric industry, and discussion of the potential for deregulation of generation is the example used as the motivation to reprice electricity on a more demand, elastic and marginal cost basis. The key thought I derived from this paper is the reality that progress in applying successfully more refined costing processes and developing more efficient prices comes one step at a time, case by case, and issue by issue. Regardless of our desire to make quantum leaps based on currently attractive economic theories, the fact is that market-based prices will be controlled by regulators who must consider availability and equity issues in addition to efficiency. For any of the players, including regulators, utility companies, and public intervenors to be otherwise is for them to reduce their likelihood of success substantially.

Mann sadly but truly describes costing and pricing of utility service in today’s environment as a “game.” His paper eloquently indicates the variety of methods that have appeared in regulatory proceedings to describe the cost of individual services or service classifications. Most interesting in this discussion is the observation that the differences in the family of fully distributed cost methodologies reviewed and within the family of marginal cost methodologies reviewed are larger than the difference between these two approaches to costing. Mann also observes that both fully distributed and marginal methods involve a number of value judgments. Despite these frailties, I agree with Mann’s conclusion that both fully distributed and marginal cost studies do provide regulators with useful benchmarks for pricing. I also agree that selection of a costing method will likely be influenced by the prior objectives of the method’s sponsor. Even so, some information is usually better than no information at all.

A point Mann makes and one with which I agree also gives me a great deal of trouble. He indicates that the primary responsibility of regulators in viewing costing and pricing issues in today’s environment is to impose constraints on pricing flexibility to protect inelastic customers. He calls this a “bargaining” process, one with more efficient costing practices than on cost causation theories. While it is true that regulators do have a responsibility to protect inelastic customers, I think it is equally important to note they have a responsibility to promote the public interest in the long run. Having determined that entry in a number of markets previously considered monopoly territory will be in the long-term public interest, regulators must be willing to adjust monopoly pricing structures to competitive market pricing structures. Failure to do this will almost certainly preclude achieving the benefits of market entry originally intended. Indeed, inefficient suppliers will be permitted into the market, while utility plants will be paid for by one set of inelastic customers rather than both inelastic and elastic customers. Even worse, in my judgment, capital committed in good faith by utility owners might have to be written off unnecessarily. While there is some question in my mind as to whether such write-offs would amount to illegal confiscation of property, even if they do not. I find it difficult to believe that investors will forget in future capital transactions the cost imposed upon utility companies by any such current government required write-offs.

The key thought to consider in the Nowotny paper is “price discrimination may be essential to maintain the integrity of utility systems.” He very clearly portrays the circumstance of plants built to serve two sets of customers (elastic and inelastic) being paid for by inelastic customers if the more elastic markets opened to competition abandon the system. He gives the example of a bar with changing market for beer to demonstrate the potential for bypass of local exchange telephone companies, for example, to affect the utilization of local exchange plant. The so-called stranded plant would be paid for, at least in the minds of telephone company management, by a shrinking body of inelastic customers whose prices would perhaps rise precipitously.

The most important point in the Nowotny paper, and one which must not be dismissed lightly, is his tentative conclusion that the answer to this problem is not in having customers pay the bill, but in asking all customers to absorb write-downs of their plant values. Nowotny asks at the end of his bar example: Is the bar worth that was paid for it? The question confronting us seems more complex since it may be possible, although undesirable, for Kinchloe, Michigan, without a bar or for the bar to deteriorate gradually because its owner is unwilling or unable to add capital at reasonable cost and with reasonable expectation of its recovery. In our essential public utility industries, however, we do not have the very well the potential for bypass of local exchange telephone companies, for example, to affect the utilization of local exchange plant. The so-called stranded plant would be paid for, at least in the minds of telephone company management, by a shrinking body of inelastic customers whose prices would perhaps rise precipitously.

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plant in times of more protection of their markets, often at
the urging of regulators interested more in high-quality un-
interrupted service than its price. Why is it fair under such
circumstances to leap from book cost valuation of assets to
market valuation of assets when the rate of capital recovery
and pricing structures continue largely under the control of
the regulator?
The punch line of the Nowotny paper, therefore, is the
notion that it is somehow unfair to consumers to ask them to
pay for what their representative in government asked investors
to commit in the first place. I think it is neither unfair nor likely
to make this request of consumers nor likely to provoke many of
them to react to the point of disconnecting utility service.
Finally, if consumers are shielded from paying these transition
costs, the risk of providing future services will increase, and
the piper ultimately will have to be paid anyway. Vickrey's paper
presents a change of pace in comparison to the other three. He readily admits that some of his
proposals may be viewed as "outrageous" while others may be
viewed more kindly but still with liberal doses of skepticism.
It is interesting to me that Vickrey proposes the
telephone system inform its users at the time of dialing as to
whether more expensive peak rates are in effect or less
expensive off-peak rates are in effect. Precisely such a
proposal was made in a New York Public Service Commission
proceeding in 1972. At that stage of system development there
was not sufficient intelligence in the network to provide these
signals economically. The concept was jokingly referred to at
the time as the "cheap-cheerful-dear-darling" dial tone system.
Perhaps New Yorkers at both the commission and at Columbia
University were just a little ahead of their time. A more
serious reading of the several proposals described by Vickrey
under the general heading of responsive pricing appear to
provide the basis for future public utility pricing perhaps
more in markets that have been opened to competition, where
consumers expect pricing to be in line with their demands.
While Vickrey would like to load level and cut total costs for
the benefit of all consumers, both elastic and inelastic, it
seems to me more feasible and more likely that competitive
markets will find a variety of pricing mechanisms most
attractive. Within the realm of possibility are prices
for telephone calls, for example, which are extremely low in
off-peak hours, thereby stimulating demand even to the point of
establishing a system peak but with higher blockage ratios than
those offered during the day at higher prices.
The one undercurrent of Vickrey's paper which troubled me
is the same one that troubled me in the Nowotny paper, that is,
the implication that the most desirable pricing schemes may not
attract sufficient revenues to cover accounting costs. Vickrey
apparently would opt for the pricing scheme and worry about
cost recovery secondarily. At this time in these important

public utility industries it appears to me to be taking the
efficiency aspects of pricing too far, too fast in relation to
the need to signal to investors their continued ability to
recover their capital and hence cause them to be willing to risk it at reasonable prices.
In summary, these four papers indicate the variety of
costing and pricing methodologies and motivations that exist
during the time of transition from total monopoly to mixed
monopoly/competitive markets for our basic public utility
industries of gas, electricity, and telecommunications. They
correctly point out that pricing and costing approaches are
affected by the motives of the proponents, and hence regulators
must carefully scrutinize them. The papers also point out
rather well the harmful consequences of failure to adjust
prices toward marginal costs in elastic markets. In this
sense, they make a meaningful contribution to the current
regulatory process, which may, in the absence of papers like
these, be tempted to continue to price as though there were no
competitive markets, thereby doing some harm in the long run
than they do service to inelastic customers in the short run.
Finally, these papers indicate the complexity of the situation
and the probability that factors in addition to efficiency will
play a large role in determining the allowable prices for gas,
electricity, and telecommunication services. These factors
will be litigated case by case, and progress will be made in
proportion to the degree to which experience bears out the
early forecasts made by proposing utilities or their customers.
In other words, it is likely that commissions will react most
where the cases for change are the strongest and least where
rhetoric is loud but the record is short on facts or reasonably
promised forecasts.