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NATURAL GAS INDUSTRY

RESTRUCTURING ISSUES

Edited by

J. Stephen Henderson
Senior Institute Economist

THE NATIONAL REGULATORY RESEARCH INSTITUTE
1080 Carmack Road
Columbus, Ohio 43210

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FOREWARD

In 1986, The National Regulatory Research Institute undertook a project specifically directed toward keeping state regulators of natural gas utilities informed about policy issues emerging from changes in the structure of the gas industry. We have done this through a series of short reports and papers related to gas industry restructuring. Two reports were published previously, and four papers are included in this report.

The two prior reports are An Economic Analysis of Block Billing for Natural Gas (NRRI-86-5, March 1986) by J. Stephen Henderson and The Bypass of Local Gas Distribution Utilities--How Can You Tell If It Is For Real? (NRRI-86-7, August 1986) by Alvin Kaufman. Both topics were selected by the NRRI Board.

One of the four papers in this report was requested by the NRRI Research Advisory Committee; this is the analysis of legal issues by Robert E. Burns. To develop topics for the other three papers, NRRI asked several well-known regulatory economists to suggest topics for papers. We selected three topics that, in our opinion, would be of great interest to state regulators of natural gas utilities.

The four papers in this volume are offered as a contribution to the public policy debate on how state regulators can best respond to the restructuring of the gas industry. The opinions of the authors are, of course, their own.

Douglas N. Jones, Director
Columbus, Ohio
September 1986

ACKNOWLEDGEMENTS

Many people have contributed to the successful compilation of these papers into a volume dealing with the restructuring issues currently confronting the natural gas industry and its regulators. The National Regulatory Research Institute expresses its appreciation to all of the authors for their willingness to participate in this project and share their expertise with the regulatory community. The project was under the overall supervision of Kevin A. Kelly who, in addition, provided his customarily excellent editorial advice. Special thanks are extended to Ms. Chris Woodyard for detailed and extensive editing on relatively short notice. Peter Nagler provided editorial assistance at several stages of this project which is gratefully acknowledged by both the editor and an author, Robert E. Burns. The editor is particularly pleased to thank Ms. Barbara Mazzotta, Ms. Jan Hilt, and Ms. Karen Myers for their professional typing of this compendium. They managed to assemble this volume in a timely fashion while adjusting to a new word-processing system.

INTRODUCTION TO NATURAL GAS INDUSTRY
RESTRUCTURING ISSUES

by J. Stephen Henderson
Senior Institute Economist
The National Regulatory Research Institute

The current adjustments being made to the structure of the U.S. natural gas industry are profound. The National Regulatory Research Institute (NRRI) issued a report in late 1985 that dealt with transportation policy and rate design issues in the context of the greater freedom of gas supply contracting that local distributors are likely to have in the future. Since that report the Federal Energy Regulatory Commission (FERC) has amended its Order 436, has issued Order 451, and nine interstate pipeline companies have accepted nondiscriminatory carrier status under Order 436. The eventual structure of the industry cannot be foreseen perfectly now, but it certainly appears to be evolving towards one in which transportation service will be offered separately from the gas commodity itself. The transportation of gas is likely to be regulated according to more-or-less traditional concepts of public utility regulation, although the methods of rate determination may vary among commission jurisdictions. The price of the gas commodity, in contrast, is being withdrawn from government regulation, and reliance is being place instead upon competition among gas producers to provide pricing discipline.

This characterization of the issue, the breaking up and separate pricing of transportation service and the gas commodity, is fundamentally an accurate one, but it is deceptively simple. Subsidiary issues underlying this change are many and complex. Industry observers frequently disagree on the resolution of the issues, which is one measure of the current state of disequilibrium in the market. Such circumstances can lead to confusion as regulators may hear conflicting interpretations of events. Such differences are inevitable since the final structure of the industry can only be guessed at now. Regulators are faced with the need to understand current industry problems, to assess the effect of policy initiatives taken in particular by the FERC, and to assimilate the analysis and conclusions of a variety of industry observers.

This volume assembles views of several issues emerging from the restructuring problems facing the natural gas industry. These are presented to the regulatory community by the NRRI partly in recognition of the reality that no single viewpoint can capture the complexity of current circumstances and partly in order to highlight some good, competent analyses that state commissioners and their staffs might not otherwise read. Of coure, not all policy matters are clarified here nor has any attempt to do so been made.

Three of the papers address the issues from the viewpoint of economics, while one contrasts the legal frameworks for regulating the long-distance transportation of electricity and natural gas. The first paper gives an overall conception of the direction that the national, and indeed world, gas market is taking and presents a view of the kind of equilibrium (not necessarily static) that we might expect in the future. In it, Arlon Tussing and Connie Barlow share their view of world energy markets and how local distributors can best realign their service obligations to correspond to gas supply and transportation portfolios. The authors are private consultants with ARTA, Inc. They have written extensively on natural gas markets and issues. They are the principal authors of the publication <u>ARTA Energy Insights</u> and a book dealing with the evaluation and structure of the gas industry.

A conclusion of Tussing and Barlow is that gas distributors will tailor their mix of long-term and spot supplies of gas, as well as their mix of firm and interruptible transportation services, to correspond to the preferences of customers. They suggest that such an outcome would make the business decisions of the distributor, such as supply planning, easier since there would be no need to contract for firm gas service for any user unwilling to pay for it. With separate prices offered for separate services, the distributor can determine customer preferences more easily than when transportation and gas supply are bundled together. They discuss a variety of ways for distributors to reduce acquisition costs in the new environment. State commissions that have not previously overseen the gas supply contracting process will find the Tussing-Barlow perspective interesting and informative.

The second paper by Robert Burns compares the legal issues regarding access to the electric transmission network to those affecting contract carriage of natural gas on the interstate pipeline network. His analysis extends the arguments presented by Harvey Reiter in the Land and Water Law Review. Burns is an attorney on the staff of the NRRI who has authored several NRRI reports dealing with electricity and natural gas issues.

Burns notes that neither the Federal Power Act nor the Natural Gas Act authorize the FERC to compel access. That is, little or no explicit statutory language can be cited by the FERC should the commission wish to require an electric utility to wheel power or to mandate the carriage by an interstate pipeline of customer-owned gas. Despite this lack of explicit authority, the FERC has used the undue discrimination and certification portions of the Natural Gas Act to fashion a voluntary nondiscriminatory carriage program under Order 436. Burns' analysis suggests that finding a legal basis for a similar program for electricity wheeling would difficult for a variety of reasons.

The current disequilibrium in the natural gas market has created a variety of unusual phenomena. Spot market prices, for example, are significantly lower than the average price of long-term contracts, most of which were signed by pipelines and producers in the past. In such circumstances, large end users might save a significant part of their gas bill if they could contract directly in the spot market. This prospect and low prices for alternate fuels threaten local gas distributors with the possibility of losing a large fraction of their gas sales. To forestall such losses, which might require that captive customers pay a larger fraction of the distributor's fixed cost, utilities may wish to offer substantial discounts to large, multi-fuel users in particular. Regulators, then, are faced with approving apparently large and possibly discriminatory differences in prices. The third paper by Daniel Czamanski addresses the limits to such price discrimination in the context of the current market disarray. Czamanski is currently a professor at the Technion, the Israel Institute of Technology. He is an Institute Associate of the NRRI who worked on many NRRI projects when he was an Ohio State University professor. He has written extensively in the field of public utility regulation, in particular, with regard to natural gas and electricity pricing issues.

Czamanski suggests several economic concepts of price limits that regulators could use as benchmarks for defining undue discrimination. His analysis is particularly appropriate in today's circumstance in which proportional pricing would result in the total loss of sales to multi-fuel users. The reader may wish to consider how the analysis might differ if this price limit, based on alternate fuel prices, were not so extreme. That is, suppose many but not all gas sales to multi-fuel users would be lost by proportional pricing. The concept of a price limit may require modification in such circumstances. In addition to limit price concepts of undue discrimination, Czamanski considers whether there is any need to regulate rates paid by multi-fuel customers at all. There are strong similarities between his argument and that presented by Tussing and Barlow in the context of the B-fuels market (boiler, bulk and black fuels).

The final paper in this volume by Rodney Lemon examines the important issue of how a local distributor contracts for gas supplies in the context of the current restructuring. Lemon is a professor in and Chairman of the Economics Department at Monmouth College. He has consulted with the Illinois Commerce Commission on public utility matters, and he has worked in the natural gas analysis section at the FERC during the period when Order 436 was being formulated. He has written extensively on natural gas matters.

State regulators must oversee the gas contracting practices of distributors, in many instances, for the first time. Lemon discusses the relative risks of long-term versus spot contracting and how a commission may wish to view the supply portfolio of a distributor under its jurisdiction. In addition, he discusses the incentives for efficient contracting that are inherent in various kinds of regulatory programs, such as automatic passthrough mechanisms versus indexing formulas. Since regulators are faced with a substantially new area of oversight, some may wish to consider innovative approaches to the problem. Lemon's analysis is suggestive in this regard.

Together, these papers cover many of the pressing issues facing natural gas regulators today. The views are not necessarily those that would be presented to a commissioner by his or her staff. Indeed, part of the purpose of this report is to enrich the set of ideas considered by state commissions during this formative time.

THE RESTRUCTURING OF THE NATURAL GAS INDUSTRY:

IMPLICATIONS FOR GAS DISTRIBUTORS AND THEIR REGULATORS

by Arlon R. Tussing
and Connie C. Barlow

ARTA, Inc.
1001 Fourth Avenue, Suite 4730
Seattle, WA 98154

Introduction

This report addresses two key issues for gas distribution companies and their state regulators in this era of industry restructuring: (i) realigning utility service obligations and (ii) formulating new strategies for gas supply.

Some of the specific issues dealt with are:

- "unbundling" distributor transportation services from gas-sales
- deregulation of commodity sales service
- priority schedules and curtailment policies
- the spot market
- price and take terms in new long-term contracts
- supply security
- least-cost purchasing strategies

Because treatment of issues pertaining to natural gas is premised upon a world view of supply, demand, and price for energy in general, the authors have included an appendix which portrays our vision of energy markets.

Service a la Carte: A New Approach to Gas-Utility Service Obligations

The Myth of Service Obligation

The energy-market upheavals of the last decade have made the obligation to serve borne by gas and electric utilities an increasingly elusive notion. Since the mid-1970s, market reality has twice grievously undermined the service obligation ideal. When put to the test in an era of shortages, the obligation to serve proved unenforceable and thus meaningless, as utilities curtailed firm customers with near impunity. More recently, utilities have discovered that few of their customers, in turn, are bound by any legal or economic obligation to be served--especially now that opportunities exist for customers to conserve, switch fuels, or hook up to another supplier. In today's gas industry, therefore:

It is uneconomic and imprudent for any utility to plan gas acquisitions on behalf of those customers who prefer to purchase or transport gas on an interruptible or short-term basis, or to incur any fixed payment obligations for the purpose of acquiring gas on their behalf. The only customers for whom a utility should plan future gas supplies, or acquire gas on long-term contract, are those who value guaranteed access to utility system gas sufficiently that they would be willing to bear whatever added costs or risks the utility must incur as a condition of that supply assurance.

It is also unfair to all classes of consumers for the utility to incur fixed payment obligations in order to obtain more supply assurance than its customers in the aggregate want to buy. Such commitments are unfair, on the one hand, to those customers who are charged for a quality of service they would rather do without. It is doubly unfair to those customers who desire and willingly pay for firm service, because it is they who will be stuck with unwanted fixed charges, should those who desired less-than-firm service reduce their sales, perhaps precisely because of their unwillingness or inability to absorb the same fixed charges.

The availability of short-term and interruptible transportation would simplify, not complicate, supply planning by the utilities. Such transportation service would allow the utilities' long-term planning efforts to disregard precisely those customers whose loads are the most speculative because their demand is most vulnerable to events over which the utilities have no control. It would, in other words, relieve the utilities of an implicit gas-sales service obligation toward customers who have no corresponding obligation to be served. So long as the utility provides transportation capacity with whatever degree of firmness the customer is willing to pay for, it will have discharged its service obligation to that customer.

Unbundling Distribution Services

There are two primary dimensions to the gas-distribution business: transportation versus sales, and reservation rights versus volumetric transactions. Reserved capacity to transport gas is distinct from a transaction to transport over otherwise unused capacity. The assured right to buy a specific quantity of gas from a utility is distinct from the actual purchase of utility systems gas that is surplus to the demands of customers having such a purchase right.

These two dimensions intersect to define four distinct goods with different supply costs and different values to different customers: transportation capacity, transportation, gas-purchase rights, and gas sales. Each of the four will have different market values, and will ultimately be sold and priced separately. There are 15 possible combinations and permutations of these services; 13 of them are plausible customer choices if we assume one cannot obtain firm gas supply without reserving firm transportation capacity, nor buy system gas without paying a variable transportation charge.

Unbundling Distributor Regulation

The buying and selling of gas, in contrast to its transportation and distribution, is inherently a competitive business. The purchase and resale of gas itself lacks continuous economies of scale, problems with wasteful duplication of facilities, or any of the other "natural-monopoly" attributes that have constituted the classic case for public-utility regulation of gas-transmission and distribution companies. The buying and selling of gas is, by virtue of these features, an industry for which public policy at the national level is already committed to fostering competition.

State regulators should give serious consideration to the opportunities opened by the insight that the buying and selling of gas is inherently a competitive business: Is there, in fact, a realistic basis for maintaining close supervision of utility gas-acquisition practices or gas-sale rates, on behalf of industrial, large-commercial, or electrical-generation customers, if these customers are afforded truly open and non-discriminatory access to a full range of transportation services?

The utilities may be correct in their claims that great purchase volumes give them a bargaining advantage in dealing with producers. This is a proposition for which they have thus far offered no empirical evidence, and one that we regard with some skepticism. Such an advantage, if it does exist, would help the utilities hold much of the low-priority sales market even in competition with direct purchases by end-users. It would not, however, eliminate competition from the marketing affiliates of interstate pipelines, or from independent marketers like Yankee, Hadson, or Northridge, all of whom will seek to exploit their own advantages of scale and their perhaps unique advantages of geographic breadth.

Service Priorities and Freedom of Choice

The only sure way of determining how much gas-supply security gas-users want (and are willing to pay for) is to give them an explicit opportunity to choose. A happy consequence of price deregulation and the end of regulation-induced gas shortages is that consumers no longer need be assigned service priorities on the basis of someone else's value and judgment; they can be permitted to choose the firmness of transportation or sales services on the basis of the relative costs. The essence of this choice is the unbundling of the four aspects of gas availability--reserved transportation capacity, transportation, firm gas-purchase rights, and gas.

Discrete access to each of these services not only allows each customer the desired mix of services, but gives the utilities and their traditional suppliers precise signals as to how much long-term supply they ought to secure at prevailing costs, in terms of price premia, pipeline demand charges, minimum-bill, and take-or-pay obligations. An unbundled framework for gas supply and transportation services would thus make it easier for utilities to plan for and serve the future needs of their customers. Unbundling of utility rates would also relieve state commissions of troublesome imponderables regarding customer demand that now plague rate proceedings.

A utility need not offer only a two-fold choice between "firm" service and "interruptible" or "best-efforts" service, because reservation rights are capable of continuous prioritization, comparable to the hierarchy of priorities in existing curtailment schedules.

The actual number of gradations to offer is an issue that ought to be delegated to the commercial judgment of the utilities--provided state regulators structure incentives that make utility managers think like managers of competitive businesses, who want to offer what they believe their customers would most want to buy. Given such incentives, a commission might well limit its ex ante guidance regarding the priority schedule to one general rule:

> No transportation customer will be interrupted because of a capacity limitation so long as gas is being transported for anyone paying a lower (or no) demand or reservation charge, and no gas-sales customer will be interrupted so long as anyone who has paid a lower (or no) demand or standby charge is buying system gas.

Likewise, construction of a gas-purchase portfolio matching the structure of consumer demand is most effectively delegated to the utilities themselves. The critical role of state commissions in long-term gas-purchase strategy is to craft appropriate profit incentives. There must be a significant and visible causal nexus between the utilities' gas-purchase behavior and their net incomes. Distributors should therefore face some risk of losing money as a result of poor portfolio construction, and the opportunity to make money on the resale of gas if they are particularly astute.

Supply Strategies for Gas Distributors

Importance of the Spot Market

There will henceforth be a pure "commodity" market for natural gas in North America, and substantial volumes of gas will move in this market.

So long as the end to surplus deliverability is not in sight, there is no basis for making any systematic distinction between the current market value of gas in spot and long-term sales. Producers will therefore be unable to extract price premia for the supply security conventionally associated with long-term contracts.

The variety of gas-sales arrangements will proliferate until natural-gas markets look something like financial markets, where the duration of transactions ranges in numerous gradations from instantaneous (spot) to decades, and in which pricing provisions in long-term contracts vary from fixed-for-life to daily redeterminations.

Nevertheless, more traditional long-term contracts will continue to exist, and may indeed remain the predominant form of sales transaction.

Redefining Long-term Contracts

In the coming environment, the most flexible (and perhaps the most abundant) form of long-term contract will contain some combination of price-redetermination, market-out, and take-or-release terms sufficient to ensure that neither buyer nor seller will ever have cause to regret entering into the deal. By the same token, this kind of long-term contract will hardly offer the producer any more security of take and price than would have been available through spot sales, and it will hardly offer the buyer any more security of supply or price than would have been available through spot purchases. The chief attraction of such a long-term contract will be that it minimizes the administrative costs and difficulties that would be entailed if the parties were to rely strictly on the spot market.

Until there evolves a clearly superior reference for establishing current market price, a wide variety of indices, formulas, and postings will continue to be used--including both field and market-netback approaches. The Gas Daily's regional tallies of spot-prices is an example of the former, while Northwest Pipeline's inclusion in its long-term contracts of a netback from Platt's quotations for residual oil at Puget Sound is an example of the latter. Because, however, both buyer and seller can freely "market-out," the main liability in the choice of a poor or inadequate price reference in such a contract is that it might contribute to the transaction's early demise.

Certain producers may be unwilling to live with a wholly flexible long-term contract, despite the growing efficiency and accessibility of the spot market. Such producers might be those in the offshore Gulf, operating in federal waters where highly permeable fields, coupled with the Rule of Capture, means that one day's loss of a market outlet can not simply be produced later--rather, it remains part of the reserve pool shared by all field lessees. On the opposite end of the spectrum are producers of associated gas. For such producers, a market-induced shutting in of gas could force the shutting in of oil production as well. Both of these producers are likely to seek contract terms in which security of take will either be assured (through minimum-take terms), compensated (through take-or-pay terms), or at least subject to sufficient prior notice.

The intelligent gas buyer today (and for the foreseeable future) would not enter into minimum-take or take-or-pay contracts absent some concession in price to a point below prevailing market value.

The intelligent gas buyer will, likewise, be cautious in entering into a long-term contract to purchase associated gas (or some form of "distressed" gas, as defined by state conservation commissions) in which state commission rules would require strict and preferential takings of this gas, regardless of the precise terms of the contract. We expect that as soon as transport access is available on all of the major interstate (and intrastate) pipelines, and abandonment of dedicated supplies becomes a routine procedure before the FERC, conservation commissions can relax these prorationing orders. Nevertheless, until that day, there is still some risk to the buyer in signing long-term contracts for supplies of associated or distressed gas.

The Obligation to Serve and Supply Security

Fundamental to the design of a supply strategy is the need for a gas distributor to define its service obligation realistically, and with it, the concomitant obligation of its customers to be served. It is essential for a utility to undertake this effort, whether or not the relevant state commission forces an explicit specification as, for example, the California Commission has done (19 March 1986 generic decision of the California Public Utilities Commission, 86-03-57).

Even more crucial than the utility's obligation to serve is the customer's obligation to be served. The institution of curtailment schedules, coupled with the newly emerged spot-market largely protects the utility from the legal risks flowing from inadequate gas supply. And as implicit or explicit statutory or regulatory directives compel the utility to purchase gas prudently, or even strictly on a least-cost basis, the customer's commitment to take becomes a more powerful guide to utility purchases. In California, for example, the PUC has directed gas distributors to purchase only spot gas for those non-core customers who do not expressly sign a service agreement to purchase system gas.

The policies adopted by the utility commission with respect to gas carriage (unbundled from gas sales) will have a powerful impact on the extent to which a gas distributor can count on customer purchases of the utility's system supplies (as differentiated from the customer's purchase of the utility's transport services alone). The minimum-volume requirements and the extent to which transport customers are allowed to deliver to multiple premises (thus enabling gas marketers to pool deliveries to customers too small to qualify for transport on their own) are key factors.

A supply disruption is more likely to occur because of a bottleneck in pipeline transport rather than because of a shortage of gas in the field. Likewise, a spot market or a resale market in transport capacity is likely to lag in sophistication behind the spot and resale market in gas supplies.

For these reasons, the choices that distributors make in ensuring access to more than one pipeline carrier, and in contracting for firm or interruptible upstream transport (either as a separate service or combined with gas supply when purchasing a pipeline's system gas) are likely to be of greater importance to the supply security for high-priority customers than the terms of gas-purchase contracts.

Likewise, the most important action that a distributor can take to ensure that it is able to meet its implicit obligation to serve high priority customers is to do all that it can to ensure that a cushion of low-priority (defined as B-fuels in the appendix) demand in its service area chooses to stay on gas. It is important for distributors to ensure that their own transport rates do not dissuade customers from using the system. Even better would be for the distributor to offer a combined commodity and transport service that would prove attractive to B-fuels customers. In this way, the utility could expect to be able to divert such gas to higher priority users, as needed.

Pursuit of Least-Cost Supplies

The best way for a utility to insulate its customers against episodic leaps in gas prices (stemming from unanticipated losses of supplies, perhaps for substitute fuels, or unusually severe weather) is by making use of its own or contracted gas storage plant, plus regular participation in the contemplated gas-futures market. It is unlikely that a distributor could find a producer (and expect to stay out of court) who would agree to price terms that follow that market down, but do not also follow the market up.

A distributor can, however, expect to be able to negotiate supply contracts (with producers, if not with pipelines) that key price changes to its own ability to secure changes in its commodity rates. This may not, of course, be of great concern to distributors who enjoy automatic fuel-adjustment clauses in their service tariffs. But even those whose commodity rates can be adjusted between annual or biennial general rate cases only through a special proceeding can find some measure of protection. If, for example, a utility wants to buy gas at a price that is fixed for the duration of its rate cycle, and subject to redetermination at the time of its general rate case, there are certainly producers and marketers who would be delighted with such an arrangement.

As to distributor purchases of spot gas, a variety of techniques are already in use: distributors can buy through gas marketers; they can send their employees out into the field to drum up contracts on their own; or they can announce monthly auctions, in which case they get to choose from the pack (pipelines, producers, and independent marketers) without having to put out a great deal of effort. (Southern California

Gas and Pacific Gas & Electric now both offer monthly sealed-bid auctions in order to play the spot market. These auctions staged by the California utilities now tend to set the spot-market price of gas in much of the Western United States and Canada and, indeed, to establish Permian and San Juan Basin prices as the lowest on the continent.)

Degree of Direct Utility Involvement in the Gas Supply Business

Perhaps the biggest decision a distributor has to face with respect to its gas-supply strategy is the degree to which it intends to find its own gas or, alternatively, purchase gas from independent marketers or the marketing affiliates of gas pipelines.

Competition among marketers will likely mean that their contracts to deliver gas will specify payment by them of penalties for non-performance. Warranty contracts, which guarantee delivery despite any deficiency in production from dedicated reserves, are likely to enjoy a revival, despite bad feelings producers may have had about the money they "left on the table" under such contracts in an era of rising prices. Buyers (or state regulators) will insist that marketers who own neither reserves nor the delivering pipeline post performance bonds or otherwise prove their financial responsibility. If such responsibility can be assured, purchase of gas from marketers may prove to be the most secure approach that a distributor can take in meeting its supply needs.

In determining the extent to which the utility wishes to involve itself in the minutiae of supply decisions, it will have to consider its present staff capabilities and the quality of computer-aided services for do-it-yourself transactions. With widespread acceptance of FERC Order 436, current knowledge of transport routes and tariffs (including backhaul rates) will be essential. What is more, there will be tremendous opportunities to economize on transport costs through the use of gas exchanges--a service that may best be handled by only the largest, most sophisticated, and geographically integrated marketing companies.

In deciding the degree to which a distribution company will rely on marketers rather than purchasing directly in the field, it will also have to consider profit opportunities and market risks, and the policies of the state commission with regard to trading gains and losses. If regulators presume that gains should be passed through to ratepayers, while losses are to be absorbed by shareholders, the utility would do better to delegate the tactics of gas purchasing and arrangement of transport to marketers who are willing to sell on a CIF basis at the city gate.

A related decision is the extent to which the company gets involved directly in the business of gas production. In contrast to the "advance-payments" programs used by interstate pipelines in the 1970s to line up gas supply (in which customers of a pipeline invested in gas exploration, but never outright owned any of the gas that was discovered), a utility would be best served by entering the business today through the purchase of gas reserves.

Cash-rich gas and electric utilities today who face little opportunity for reinvestment of funds in expanded facilities are in a good position to strike deals with cash-short producers (or the bankers who have foreclosed on them). A holding-company structure may be appropriate for this new venture. And because of the emerging availability of so-called "black-box" transport services (a reference to transportation arrangements complicated enough to require a computer to piece together routes, schedules, and prices) the company could satisfy regulators (if necessary) that the gas is indeed being used by the utility's customers, regardless of its location. (Black-box transport will be performed by transport brokers and gas marketers who agree to take gas from one location and deliver it to another for a fee. The most efficient brokers and marketers will use exchanges in so doing.)

Appendix: Fundamentals of Gas Prices and Supply

The "B-fuels" Market

The prices of all major fossil fuels (natural gas, oil, and coal) will be set globally in their competition with one another to serve the lowest-priority uses--the "B-fuels" market ("boiler", "bulk", or "black" fuels), in which the object of demand is calories as such.

About half of the world's primary energy consumption is of the B-fuels variety, and a substantial and growing fraction of this market has the installed capability to switch fuels. The fact that such uses are marginal (in the economic sense) for each of the primary fuels means that the prices of all of them will tend to converge toward the cost of the fuel whose supply is most elastic.

In this competitive scenario, the price of each fuel is therefore capped by the supply cost of its cheapest alternative; but no fuel drives the prices of others. Unlike the situation in the early 1970s, oil in particular is no longer the indispensable fuel whose cost dominates the prices of the rest.

Oil still has a unique role in global energy-price determination because it is the cheapest energy form to move between continents and, as a result, oil prices unify the world B-fuels market, creating a price link between widely separated markets for natural gas and coal. Oil prices will thus continue to be the chief indicator of the state of energy markets generally. (In this report, therefore, we shall use oil-price levels in 1986 U.S. constant dollars as representative of the level of energy prices generally.)

Fuel-switching in the B-fuels market means that disruption in the supply or a longer-term decline in the producing capacity of any one of the three primary fossil fuels will not, therefore, bring about an absolute scarcity in B-fuels nor a catastrophic price fly-up.

The robustness and flexibility in the B-fuels market means, likewise, that a supply disruption, a decline in producing capacity, or a weather-induced surge in gas-heating demand has to be great indeed before it can bring about markedly higher prices, even in regions or end-use sectors that are singularly dependent on one form of fossil fuel.

The fallacy that led people to believe that OPEC could orchestrate oil-price increases to as high as $60 or $100 per barrel was the notion that hydrocarbon liquids were indispensable in all of oil's major end-uses, and that it was thus only the high cost of synthetic oil-imitations (from coal, oil shale, or biomass) that would ultimately put a cap on OPEC oil prices--rather than the lowest-cost substitutes, liquid or otherwise, for OPEC oil in a sufficient number of end-uses. When oil prices surpassed $20 in 1979, a broad range of such alternatives was mobilized, including non-OPEC oil, coal, natural gas, and conservation, all of which were available in unexpected volumes and at costs much lower than that of synthetic hydrocarbon liquids. The lowest-cost measures available were the use of coal and gas in place of oil for B-fuels applications. In the U.S. alone, as a result, residual-oil use fell by 1.8 million barrels per day, or 60 percent, between 1978 and 1985.

Energy-Price Indeterminacy and the Range of Plausible Prices

All fossil-fuel markets are commodity markets; as such, they are inherently cyclical. While there has been no identifiable long-term trend in oil price over the past 135 years, the average yearly fluctuation in the average wellhead price of U.S. crude oil has exceeded 20 percent, up or down.

Between 1878 and 1978, crude-oil prices never exceeded $15 in 1986 dollars; the average U.S. wellhead price for the entire century was between $8 and $9. The exceptionally high prices between 1979 and 1985 were possible only because of an unprecedented heavy dependence of the world's B-fuels markets on oil, which in turn stemmed from the exceptionally low oil prices that prevailed in the 1950s and 1960s.

The energy-price upheavals since the early 1970s have brought about two fundamental structural changes in the world's energy economy: (i) pervasive and continuous competition among fuels, and (ii) unprecedented competition within the oil sector--in contrast to the period before the 1970s, in which crude oil moved almost totally within channels controlled by a handful of major producer-refiners or (in the United States) by state conservation agencies.

There is no present prospect of either (i) a new supply-side production-control mechanism like the world cartel of integrated majors which, together with the Texas Railroad Commission and sister agencies in other states, stabilized oil prices for more than three decades prior to 1971, or (ii) an effective successor to OPEC, which succeeded in moving prices unidirectionally over the subsequent decade.

While the introduction of widespread fuel-switching capacity will serve as a demand-side moderator of the wide price swings that are typical of commodity markets, the new prevalence of spot sales and other arms-length transactions for crude oil assures considerable oil-price volatility within the range of prices at which oil competes vigorously with gas or coal for B-fuels markets. The emergence of natural-gas spot markets and market-sensitive terms in long-term gas-purchase contracts means that wellhead gas prices are likely to show a similar volatility.

Fuel-switching capacity, together with the supply response (increased production of all fossil fuels) to the extremely high prices of the past ten years, probably rule out a sustained return, anytime in this century, to the high oil prices that prevailed between 1979 and 1985. This is because (i) existing investment in fuel-switching capacity and in facilities for producing and transporting fossil fuels are both long-lived and more than adequate for current needs; and (ii) the memory of recent price upheavals and supply curtailments insures that a large proportion of new B-fuels-using facilities will have dual- or multi-fuel capability.

Future Prices

No sound scientific basis exists today for predicting whether the bottom of the present cycle in oil (and gas) prices will occur this year, five years, or ten years hence, and whether its level will be $12, $5 or somewhere in between (in per-barrel oil equivalent). Consider, for example, this heuristic exercise: suppose that everybody had recognized in 1975 (as few actually did) that oil markets were cyclical, with prices doomed to rise and fall periodically. What economic model, and what set of geological and geopolitical facts, could one have selected--even with the gift of today's hindsight--to forecast accurately that prices would peak at $34 in 1981, rather than at (say) $17 in 1979 or $55 in 1985?

The range between $10 and $20 (1986 U.S. dollars) in per-barrel oil-equivalent nevertheless seems to be the sustainable range of primary-energy prices and to bracket the likely long-run global equilibrium price for fossil fuels.

(i) Prices much below $10 appear to make most large-scale oil prospects outside the Middle East (the deep offshore and the Arctic, for example) uneconomic to develop, and are too low to shelter investment in new, large-scale gas-transport infrastructure (transcontinental pipelines and intercontinental LNG projects). Such prices will thus quickly thrust the world into renewed dependency on the "core" countries of the Arabian Gulf (chiefly Saudi Arabia, Kuwait, and the Emirates), which alone possess sufficient resources of oil producible at $5 per barrel or less. These countries have no interest, however, in pricing their product below the cost of alternative fuels.

(ii) At prices much above $20, on the other hand, oil loses almost the entire global B-fuels market to gas, coal, and other energy sources. Surplus oil-producing capacity would thus reappear rapidly even outside the countries of the Arab core.

The absence of market-stabilizing institutions like the former cartel of major oil companies (the Seven Sisters) or the Texas Railroad Commission means that political events, coupled with the moods of traders and speculators, might from time to time send oil prices below \$10 or above \$20. These excursions are not likely to be long-lasting or credible enough, however, to dominate consumers' long-term fuel choices, or energy-industry investment behavior.

Crude-oil prices in the \$10-to-\$20 range at tidewater imply delivered prices for residual oil at 80-to-100 percent of these levels, or \$1.30 to \$3.25 per million Btu. This is the delivered price range within which gas must ultimately compete for the B-fuels market.

Over the last four years, spot-market prices for natural gas in North America, and prices in market-responsive long-term contracts have been falling through the range described above. Wherever industrial end-users have been able to purchase gas directly from producers, or where pipeline and distributor margins above current producer prices have been moderate, gas has until 1986 easily underpriced heavy fuel oil.

Market prices for gas substantially under the residual-oil equivalent since 1983 have, therefore, reflected gas-to-gas competition in a surplus market, rather than gas-to-oil competition. In the second quarter of 1986 open-market prices tend to be in the \$1.25 to \$1.75 range, and continue falling--into a range where gas will begin to compete vigorously with coal in established dual-fuel facilities.

For the short term, the most likely sticking point for wellhead gas-price declines is the higher of:

(i) the level at which displacement of coal could absorb the current excess of deliverability, and

(ii) the price at which a sufficient number of producers believe that the present value of their reserves would be enhanced by shutting in production now, in order to sell later at a higher price.

Either of the foregoing criteria would permit additional gas-price declines in the short term. Producer perceptions of the replacement cost of natural-gas reserves influence the price floor only to the extent that they affect expectations about the future. If gas producers believe that, within three years and indefinitely thereafter, they will be able to sell gas at, say, 75 percent of the price of $18 per barrel heavy fuel oil ($2.25 per million Btu), it is not in their interest to withhold production unless the wellhead price falls below about 90 cents at the most. (This calculation is based upon the present opportunity cost of a three-year suspension of production, at an inflation-adjusted discount rate of 10 percent, and maximum feasible depletion rate of 12.5 percent. The resultant 90 cents per mmbtu is likely to be considerably higher than the actual reservation price for many producers, to the extent that curtailing production now would reduce ultimate gas-recovery, because of drainage, water-infiltration, or other problems.)

The effective floor price will not be any lower than set out above, however, despite the fact that many producers may be desperate for cash. Such hard-pressed producers will do better in present-value terms by selling their reserves to better-financed parties (at a price for reserves that reflects current expectations about future gas prices) than by dumping their gas into the current market at prices lower than, say, 90 cents (if the assumptions set out above regarding producer perceptions are correct). Although not all producers can be expected to act in this ideal manner, many probably will do so, and in turn, they will determine the amount of production that would be withheld from the market at prices that seemed too low.

A single supply-demand equilibrium point for natural gas is a phantom concept because of:

(i) inherent volatilities in B-fuels prices and market penetration by competing coal and fuel oil, and

(ii) the highly seasonal nature of gas demand. A supply equilibrium point, in theory, could be anywhere from a low that would fulfill only high-priority demand in the winter (with B-fuels customers drawing on gas only during the summer) to maximum deliverability that would be able to serve B-fuels demand fully around the year, but would also require producers to live with significant volumes of shut-in reserves during the summer months.

If an equilibrium is reestablished in which gas, heavy fuel oil, and coal all share the B-fuels market in North America, wellhead prices of natural gas will tend to have the following configuration:

(i) Wellhead prices of gas from Appalachia and the Canadian offshore will reflect netbacks from either the price of medium-sulfur (.5 to 1.0 percent S) residual oil in the Northeastern States or, if coal and gas displace all heavy fuel oil from this market, the delivered price of gas from the Gulf Coast. (At prices like those that now prevail, however, it is unlikely that the netback values for Atlantic offshore gas moved through newly-built pipelines would be sufficient to justify development of reserves for production.)

(ii) Wellhead prices of gas from the Gulf Coast and Midcontinent will reflect netbacks from medium-sulfur residual oil in the Midwest or, if coal and Canadian gas completely displace heavy fuel oil from that region, netbacks from medium-sulfur residual oil in the Northeast.

(iii) Wellhead prices of gas in Alberta and in the Rocky Mountain overthrust belt will reflect netbacks from the price of medium-sulfur residual oil in the Midwest or, if gas and coal completely displace heavy fuel oil from these markets, the delivered price of gas from the U.S. Gulf Coast.

(iv) San Juan and Permian Basin gas prices will reflect a netback from the cost of low-sulfur (.3 percent or less S) in California or, if gas completely displaces heavy fuel oil from this market, the higher the netbacks from the delivered price of Canadian gas in California or the field price at the U.S. Gulf.

The pricing scheme described above is now in effect, because the surplus of gas-producing capacity has resulted in gas-to-gas, rather than gas-to-residual-oil competition. It is important to recognize, moreover, that recent spot prices for gas have been depressed by lack of producer and buyer access to pipeline transport, as well as by surplus deliverability. Widespread adoption, soon, by pipelines of transport programs pursuant to FERC Order 436 should lead to intensified competition among pipelines for incremental transport volumes, and thus to a convergence between wellhead prices and the plant-gate prices of competing fuels. Ultimately, competition among carriers can be expected to narrow differences between spot-market producer prices and delivered prices faced by large-scale B-fuel users, and differentials in such prices among the various regions of North America, to little more than the variable costs of transport; these may only be a few cents per million Btu.

Physical Bounds of Gas Supply

Because of geological, physical, and political differences, the prospect for future significant finds of new energy reserves in North

America (and globally) is more favorable for gas than it is for oil. This is because:

(1) Significant volumes of gas may be of abiogenic as well as biogenic origin.

(2) Gas, as a vapor, is compressible; therefore the deeper one drills for gas, the richer tend to be the reserves per volume of reservoir stratum. Oil, on the other hand, is not only incompressible, but it tends to "cook" away into simpler hydrocarbon molecules (notably, methane) between depths of 9,000 and 16,000 feet.

(3) Producers have only just begun to search for natural gas: In the early decades of the natural gas industry (and even today in less developed countries), the difficulties in transporting vapors discouraged exploration in remote areas; more recently, and until 1978, a regulatory cap on wellhead prices depressed production incentives.

It is not unreasonable to conclude that the supply of natural methane is, for all practical purposes, unlimited--at some price. Since both demand and supply are highly variable as a function of price, there is little prospect of persistent shortages or surpluses of gas, in the absence of institutional obstacles to the necessary price adjustments.

Volumetric supply projections are thus meaningless except when stated as a function of expected price. But geological concepts, exploration and production technology, and above all, the price and regulatory environment of the North American gas industry have been changing rapidly. In our opinion, the changes have been so profound that one can place little faith on any price-related supply-estimation technique that depends on extrapolation of historical experience, or otherwise upon analyzing trends in observed physical, physical-economic, or economic ratios. At long-term prices under about $3, uncertainty about potential Canadian supply probably overshadows uncertainty about Lower-48 U.S. production potentials.

On a world scale, the big successes in petroleum exploration in recent years have been in gas rather than in oil, notwithstanding the fact that most exploration effort (outside North America, at least) has been directed toward oil. From 1978 to 1984, the world reserve-to-production ratio for natural gas increased 33 percent, from 49 to 65 years. These reserve discoveries were three times greater than the amount of gas consumed globally during the same period, and equivalent to about 30 years of OPEC oil at today's production levels.

Gas discovered outside the North American continent is relevant to natural-gas market conditions in the United States even if its transportation to the U.S. is uneconomical. The presence of substantial reserves in the Soviet Union and the North Sea, for example, and in numerous less developed countries, tends to free up greater volumes of oil for sale into the B-fuels market worldwide.

A reserves-to-production (R/P) ratio of ten years or less may be the most efficient level from an economic standpoint, despite the norm in the 1950s and 1960s of 20 or higher. This is because the average gas field in North America has a physical character that yields the highest profits to producers (on a discounted cash flow basis) if it is produced in ten or fewer years. The R/P ratio for the U.S. Lower 48 bottomed out (because of slumping demand) at about 8 in 1980 and 1981--the very time during which the shortages that emerged in the 1970s disappeared.

No physical shortfall in gas supply, relative to current consumption levels, is thus an immediate prospect, even if discoveries fail to keep pace with production. Lower-48 reserves now equate to about 9 years of production at current levels, and the non-frontier reserves of the U.S. and Canada combined are more than 12 times the current yearly production level. If new reserves replaced only two-thirds of annual North American consumption, at the present rate of 20 trillion cubic feet per year, it would be 1998 before the combined U.S.-Canadian R/P ratio fell below 8.0.

Economic Determinants of Gas Supply

The market dynamics described previously imply that the general price level for natural gas in North America may be nearly insensitive over the long term to the material cost of finding and developing gas in North America. Within a broad range of supply potentials, that is, natural gas will be priced at a level that permits it to be delivered to B-fuels users in competition with heavy fuel oil or coal. This is likely to be the case except under either of two extreme and highly improbable contingencies:

(i) If methane proves so abundant on this continent at such low costs that it effectively drives oil and coal from the B-fuels market altogether, and thus initiates an era in which gas-to-gas competition is the sole arbiter of the general energy price level in North America, or

(ii) If the finding and development costs of incremental gas supply in North America are so high that no gas is available to serve the B-fuels market, in which case the price would be set by the coincidence of this supply cost with the value of gas in higher applications--home heating and process-fuel uses, for example.

More likely than either extreme case, however, is the competitive scenario described before, in which gas continues to share in and compete for the B-fuels market with coal and residual oil. If natural gas remains competitive in the B-fuels market, the supply cost function will ultimately govern the amount of gas forthcoming at the prevailing price, rather than that price as such, and will therefore determine the share that gas will hold in the total primary-energy market. To the extent that natural gas companies (pipeline companies and local gas distributors) shift their business from resales toward carriage, or reform their gas-acquisition practices along the lines described previously, it is the volume of gas sales, rather than the absolute price of gas, that should be their greater long-term concern.

Nevertheless, so long as the supply-cost function makes gas an attractive commodity in the B-fuels market, the demand cushion provided by this market virtually ensures that supply disruptions (owing to political, weather, infrastructure, or any other problem) will have little if any impact on higher-priority users of gas. Distribution companies mainly serving high-priority consumers should have little difficulty finding enough gas somewhere--perhaps in the spot market, at some reasonable price, to meet their requirements.

For the short term (until, say, 1990), annual deliverability will continue to exceed demand by a wide (and likely growing) margin. Nobody knows, within a margin of fifty percent, how large the physical surplus of deliverability is in the United States. Release of gas now under long-term contract to interstate pipelines (via the newly relaxed FERC abandonment procedures and in conjunction with settlement of take-or-pay disputes) is nevertheless certain to increase the volumes offered for sale into the spot market.

A tremendous imponderable that makes precise calculation of the U.S. gas surplus irrelevant is the extent to which political barriers to gas trade are eased by federal and provincial authorities in Canada. The expected reduction of the reserves protection for domestic consumption in Canadian export-licensing regulations from 25 years to 15 years would immediately free an additional 16 trillion cubic feet (just about one year of total U.S. consumption!) for export.

Certainly, over the short-to-mid term, transportation bottlenecks or disruptions (especially seasonally) are more likely to put a cap on gas deliverability at the city gate than are field conditions in the aggregate.

"ACCESS TO THE BOTTLENECK":
LEGAL ISSUES REGARDING
ELECTRIC TRANSMISSION AND
NATURAL GAS TRANSPORTATION

by Robert E. Burns, Esq.
Senior Research Associate
The National Regulatory Research Institute

The need to provide access to gas and electric transmission facilities has been written about a great deal lately. Advocates of third-party access hope that a genuinely competitive market can be created by allowing third parties to buy gas or electricity directly from producers. There are certain industry structural problems, legal and institutional barriers, and technological impediments, however, that make such access difficult to arrange, particularly in the electric utility industry. This report addresses the legal barriers faced by third parties attempting to gain access to electric and gas transmission facilities.

This paper was written at the suggestion of The National Regulatory Research Institute's Research Advisory Committee. It revisits the legal theories developed in Harvey Reiter's premier law review article, entitled "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts."[1] Reiter's legal theories are analyzed by the author in the light of the current events in the gas and electric utility industries. The author observes where both industries are today and develops his own ideas of where they might go from here.

The analysis is presented in three sections. The first addresses the structure and technologies of the electric and gas industries. The second section presents a comparison of the legal frameworks within

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[1] Reiter, "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts," 18 Land and Water L.R. 1 (1983).

which the gas and electric utility industries are regulated. The final section presents some analyses and conclusions about the interaction between industrial structure and the law.

Industrial Structures and Technologies

The development and application of the law regarding the regulation of an industry is affected by the industry's structure and its technology. As industry structure or technology changes, then the application of the law to that industry must also change. The law adjusts to changes in technology by providing for industry restructuring. Conversely, a change in industry structure can also lead to the growth and development of new technologies. In the first subsection, a snapshot view of the current state of industrial structure in the gas and electric utility industries is presented, after which the legal implications of certain critical technical aspects of the gas and electric industries are discussed.

A Brief Overview of the Industrial Structures

Although there are profound differences between the electric and gas industries, both have a structure that can be described in terms of production, transmission, and distribution functions.

Production

For both industries, there are diverse sources of production. The gas utility industry has several thousand gas producers, most of whom are independent of the gas pipelines. Electricity, on the other hand, is, for the most part, produced by central power stations that are owned and operated by the same vertically-integrated electric utility that owns and operates the transmission and distribution facilities. There are, however, several significant exceptions to this vertically-integrated structure. There are, for example, also cogeneration and small power production facilities that are independently owned and operated. Sections 201 and 210 of the Public Utility Regulatory Policies Act requires utilities to buy the power generated by qualifying cogeneration and small power production facilities at the utility's avoided costs. These entities are a competitive force in the power production market. Also, several investor-owned utilities have entered into joint ventures to build their generation facilities. There is even an occasional generation company set up solely to generate and sell bulk power. However, the number and the proportion of sales by independent producers is greater in the gas industry than in the electric utility industry. Because there are a greater number of entities at the production level in the gas industry, a competitive market structure would be more probable there than in the electric utility industry.

Transmission

At the transmission level, the electric and gas utility industries have certain similarities. For both industries the transmission function has significant economies of scale. In the electric industry, there are economies of scale, particularly for high voltage lines. Indeed, for high voltage lines and their associated equipment, both capital and operating costs of the facilities increase in approximate proportion to the voltage, *ceteris paribus*;[2] capacity to carry power increases more or less as the square of the voltage, however. Thus, the larger the capacity of a transmission line, the cheaper the unit costs of transmission. Further, there are entry barriers to building electric transmission facilities: only a limited number of transmission corridors are available. While this latter restraint--state commissions and

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[2] See Meeks, "Concentration in the Electric Power Industry: The Impact of Antitrust Policy," 72 Columbia L.R. 64, 74 (1972).

siting agencies not allowing transmission facilities to be built just anywhere--is institutional, it is nonetheless real. Taken together, these factors make a duplication of electric transmission facilities uneconomic.[3]

The same factors apply to gas transmission facilities. For all gas pipelines, the costs are more or less proportional to the pipeline's radius, whereas capacity increases with the square of the radius. Again, the larger the capacity of the transmission lines, the cheaper the unit costs of transmission. Further, entry may be inhibited by the high cost of exit. As pointed out by Williams, an owner will lose most of his investment if a new pipeline fails in its market.[4] Also, the Federal Energy Regulatory Commission and its predecessor the Federal Power Commission have restricted entry of interstate pipelines through their certification processes. Section 7(c) of the Natural Gas Act provides that no interstate natural gas company shall undertake the construction or extension of its pipelines unless it has acquired from the Commission a certificate of public convenience and necessity.[5] However, as noted by Williams, the interstate gas transmission market presents a mixed picture of oligopoly and monopoly with just under half (49.5 percent) of the interstate pipeline gas sales being made to distributors served by three or more suppliers.[6]

In the electric utility industry, the transmission facilities are almost entirely owned by relatively large private systems. The only major exceptions are the lines owned and operated by federal power authorities.[7] There are also minor exceptions where a publicly-owned

[3] It should be noted that an alternate transmission line must always be available to maintain the reliability of the transmission system. See Meeks, at pp. 70, 74.

[4] See Stephen F. Williams, The Natural Gas Revolution of 1985 (Washington, D.C.: American Enterprise Institute for Public Policy Research, 1985), p. 4.

[5] See the Natural Gas Act, section 7(c).

[6] See Williams, pp. 4, 12.

[7] See Meeks, pp. 68-69.

rural cooperative may own a transmission system, often as a part of a joint venture with other rural cooperatives.

For the gas industry, the major interstate transmission systems are owned by private companies. Their pipelines run parallel from the major gas fields to major gas markets. While a particular gas producer or gas distribution company may face a single buyer or seller, it is often the case that there is a potential competitor not far away. With some notable exceptions, the major gas pipelines are usually not part of a vertically-integrated system running from producer to distributor.[8]

Distribution

At the distributor level, both electric and gas companies are considered to be monopolies because a duplication of distribution facilities would be uneconomic. However, it is worth noting that many large industrial customers buy gas directly from gas transmission pipelines. Similarly, some large industrial customers take their electricity directly from the transmission or subtransmission system. These customers help to create competitive pressures in both markets.

A critical difference between the gas and electric industry structures is that many gas distribution systems are owned by companies (or municipalities) that are independent of their pipeline suppliers, while electric utility distribution systems are often vertically integrated with the same company that owns the generating plant and transmission system. And, as mentioned earlier, gas distributors are more likely than not to have access to two or more gas transmission companies.[9] For the electric distribution systems, the situation is more complex. While most are owned by a relatively large, vertically-integrated electric utility company, there are often several smaller cooperative

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[8] One such notable exception would be the Columbia gas systems, which owns its production subsidiary, pipeline, and distribution companies.
[9] See Williams, pp. 4, 12. According to Williams, 77.5 percent of interstate sales go to distributors served by two or more suppliers.

and municipal distributors existing within their systems. These small enclaves often purchase power at wholesale from the larger system.[10]

A Brief Discussion of the Technology of Transmission

The technologies of gas and electric transmission are similar in one respect: both gas pipelines and electric utility transmission lines are, as previously mentioned, subject to economies of scale up to a limit. For both industries, transmission capacity increases more rapidly than the costs of building the capacity. Also, for both industries, once the gas or electricity enters the transmission system, it is fungible. The gas becomes comingled with all other gas entering the pipeline. Electricity becomes part of the bulk power generated from a multitude of sources.

There is a key difference between gas and electricity transmission, however. While it is possible for a specific quantity of gas to move along a contract path from producer to customer (though the gas the customer receives may not be the same gas that came from the producer's well), it is extremely difficult to direct the flow of electricity. Most of the United States electric transmission system is comprised of alternating current (AC) lines. The flow of power in AC systems is governed by laws of science. These laws provide that power flows through all paths between the points, dividing itself through parallel paths having different power capacities. In actual transmission system operation, power flow over various paths sometimes causes loop flow, i.e., power circulating around the intended transmission path. Because the flow of electric power--although it can be predicted--cannot be easily controlled, it is improbable at best that the actual path of all the power flow between two points will be over the contract path. Neighboring utilities' transmission lines are likely to be affected, and distant utilities may be affected to a lesser extent. Overloading of

[10] See Meeks, pp. 68-69.

neighboring or even more distant transmission systems can occur, resulting in a loss of system reliability. Because the flow of power does not recognize corporate boundaries, the technical soundness and economic fairness of bulk power transfers over transmission lines can be called into question.[11]

A Comparison of the Legal Frameworks

This section provides the reader with a comparison of the legal frameworks concerning access to gas pipeline and electric transmission facilities. There are three subsections. The first contains a discussion of the regulation of access to gas pipeline facilities. The second covers regulation of access to electric transmission systems. The third contains a discussion and analysis of Harvey Reiter's groundbreaking law journal article on the subject of access to both gas pipeline and electric transmission systems.

"Access to the Bottleneck": The Status of Regulation in the Gas Industry

To understand the current status of regulation concerning access to gas pipeline facilities one must look at the historical development of the industry since the passage of the Natural Gas Act.[12] The Natural

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[11] It is not the purpose of this report to solve these issues relating to transmission of electricity. Rather these issues are raised here simply to point out that gas and electricity transmissions are not the same. For a more detailed discussion of technical and institutional impediments to wheeling, See John A. Casazza, "Understanding the Transmission Access and Wheeling Problems," Public Utilities Fortnightly, October 31, 1985, pp. 35-42.

[12] See generally the discussion on historical development found in Illinois Commerce Commission Sunset Monograph No. 2: The Gas Industry: Changes and Challenges (Springfield: Illinois Commerce Commission, 1984) and Kevin A. Kelly et al., State Regulatory Options for Dealing with Natural Gas Wellhead Price Deregulation (Columbus, Ohio: The National Regulatory Research Institute, 1983), at appendix B, pp. 293-325.

Gas Act was enacted in 1938, in part, to promote the construction of natural gas pipelines. In the early years, the Federal Power Commission was concerned about the large capital expenditures required to build a pipeline to transport natural gas which was then an inexpensive (and in many cases free) commodity. To assure that pipelines would not be built only to have their gas supply depleted after a short time, the FPC required the gas pipeline companies to have supply reserves of 30 years and contracts with producers of 15 years duration before the Commission would certify the construction and operation of those pipelines.

At first, the wellhead gas prices charged by the producer were not regulated, but in 1954 the United States Supreme Court ruled in the Phillips Petroleum Company v. Wisconsin case that the FPC had to regulate the wellhead price of gas dedicated to interstate commerce.[13] After a failed attempt to regulate the producer's gas prices on a well-by-well, cost-of-service basis, the FPC adopted an areawide pricing strategy. Unfortunately, each areawide rate case required years to process. In the meantime, the cost of production was increasing while prices remained frozen at the 1960 levels. Because the cost of new wells rose and the price of interstate gas did not, new gas production mostly was committed to the intrastate market. In order to raise the price of gas in the interstate market to encourage new production in that market, the FPC raised the price of gas from newer vintages of wells. However, the increases in price were still less than the increase in the price of oil, and industrial fuel switching from oil to gas resulted. In the mid-1970s, shortages occurred in the interstate market. Because of this crisis, Congress enacted the Natural Gas Policy Act of 1978 (NGPA). The NGPA provided a phased, partial decontrol of gas, with most of the new gas decontrolled in 1985. High-cost gas from deep wells, Devonian shales, geopressurized brine, and coal seams was deregulated immediately. The NGPA price control scheme provided for a multiple tier of prices for the different categories of gas. Generally

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[13] Phillips Petroleum Company v. Wisconsin, 347 U.S. 672 (1954).

speaking, lower prices were provided for old gas and higher prices for new gas. Because consumers were charged a rolled-in price for gas, the interstate pipelines, from 1978 through 1982, entered into contracts with price provisions for new gas that exceeded the market-clearing price. Also, pipelines agreed to high percentage take-or-pay clauses in order to compete for scarce supplies.[14]

Transportation Programs under the NGPA

The gas shortages disappeared and the supply bubble grew in their stead. Indeed, because of the high cost of gas, by 1982 the gas pipelines began to lose the industrial market to alternative fuels. Gas pipelines responded by reducing prices and take-or-pay obligations. In order to protect their markets, the pipelines devised special marketing programs to cut prices for large industrial customers that could easily switch to No. 6 fuel oil.[15] The FERC facilitated this marketing approach by issuing in 1983 several orders. These orders set up four FERC programs: (1) blanket certificates, (2) special marketing programs (SMPs), (3) off-system sales, and (4) special discount rates.[16] The FERC also allowed the pipelines to establish modified fixed-variable rate designs to shift more of a pipeline's costs away from the commodity charge in order to encourage interruptible customers to purchase greater volumes of gas.[17] Further, both FERC and the state commissions allowed pipelines and gas distributors to implement innovative rate designs, such as flexible gas pricing linked to alternate fuel prices, to

[14] Williams, p. 10.
[15] Ibid., pp. 10-11.
[16] Alvin Kaufman, Donald P. Dulchinos, and Robert D. Poling, Natural Gas: On the Road to Deregulation, Report No. 85-1405 (Washington, D.C.: The Library of Congress, Congressional Research Service, 1985), pp. viii-ix.
[17] Ibid., p. ix.

reallocate costs or simply reduce prices.[18] Of these, the special marketing and blanket certificate programs were the most significant in the restructuring of the gas industry--not because of what the programs did, but because of their illegality.

As noted earlier, most pipelines entered into long-term gas purchase contracts for more expensive gas. These contracts had high percentage take-or-pay provisions. When the market-clearing price of gas fell, pipelines attempted to invoke force majeure provisions in their contracts so that they could avoid their take-or-pay liability. Often the pipeline would shut-in the producer. A producer had two alternatives. He could go to court to try to enforce his contractual rights (an expensive and often time-consuming option that could lead to his insolvency), or he could compromise with the pipeline by relinquishing his contractual rights in exchange for the certainty of selling more gas, albeit at a lower price.[19] Special marketing programs were filed by the pipelines to make such a compromise possible. The pipelines would release the producer from certain specified gas supply requirements and would transport that released gas directly to end users.[20] In exchange, the producer would credit the pipeline's take-or-pay obligation for the released gas that was sold.[21] The pipelines limited the program to users who would have switched to other fuels if gas were sold at a higher price. In this way, producers did not lose profits on gas they could sell at a higher price, and the pipelines were not adversely affected.[22]

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[18] Ibid., also see generally J. Stephen Henderson et al., Natural Gas Rate Design and Transportation Policy under Deregulation and Market Uncertainty (Columbus, Ohio: The National Regulatory Institute, 1986).
[19] Nowak and Leitch, "Maryland People's Counsel: Will It Spur Changes in FERC's Regulation of the Natural Gas Industry?" 6 Energy L.J. 265, 268-269 (1985).
[20] The pipelines would file under section 7 of the Natural Gas Act for authority to transport the released gas.
[21] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2d. 768, 771-772 (1985).
[22] Nowak and Leitch, at pp. 268-269.

The blanket certificate program was a FERC program that allowed pipelines to transport gas pursuant to a one-time, blanket certificate, instead of individual certificates for each transaction. The program was intended to facilitate direct sales of gas from producers to end users. While the blanket certificate program as established by the FERC was open to all end users, the filings by individual pipelines tended to exclude their captive (non-fuel-switching) customers.[23]

Maryland People's Counsel I & II

In two companion cases, the District of Columbia Circuit Court invalidated the special marketing and blanket certification programs.[24] In the first of these cases, Maryland People's Counsel I, the court found that the FERC had failed to set forth a reasonable basis for believing that the SMPs, which were only available to industrial users with fuel-switching capabilities and not available to captive customers, would benefit all pipeline ratepayers. The court found that the FERC had failed to articulate a sufficient justification for excluding captive customers from the SMPs, in effect finding the SMPs to be unduly discriminatory. The court ordered the FERC to show cause why similar SMPs should not be vacated. Ultimately, the court permitted the SMP orders to terminate as scheduled on their October 31, 1985 expiration date.[25]

In Maryland People's Counsel II, the court held that the FERC had a duty to consider the anticompetitive practices that were possible under the blanket certificate programs, which were reshaped by the pipelines

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[23] Id. at p. 272.
[24] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2nd 768 (D.C. Cir. 1985) (also known as Maryland People's Counsel I); and Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2nd 780 (D.C. Cir. 1985) (also known as Maryland People's Counsel II.)
[25] Maryland People's Counsel v. Federal Energy Regulatory Commission, 768 F.2d 450, 455 (D.C. Cir. 1985).

to include fuel-switching customers and exclude captive customers, before the orders allowing such programs were promulgated.[26] The court vacated the orders to the extent that they allow transportation of direct-sale gas to fuel-switching customers without requiring the pipeline to furnish the same service on a nondiscriminatory basis to local distribution companies and captive customers.[27]

FERC Order 436

At the time that the D.C. Court of Appeals issued Maryland People Counsel I & II, the FERC was considering two Notices of Inquiry (NOIs) that had been issued. The first NOI focused on the gas transportation programs then in effect and what should be done to have those programs complement one another and other FERC regulations. The second NOI focused on pipeline rate designs and service terms with particular attention to the changing risks in the industry and how tariff provisions shift those risks.[28]

The rulings of Maryland People's Counsel I & II changed the picture with regard to the gas transportation NOI by obligating the FERC, first to allow no transportation program with potentially discriminatory effects, and second to develop an open, nondiscriminatory program in which all users share in the benefits.[29]

The FERC took up this challenge by issuing a Notice of Proposed Rulemaking (NOPR) on May 30, 1985.[30] The NOPR proposed a package of

[26] Maryland People's Counsel II, p. 787-9.
[27] Id. at p. 789.
[28] FERC Notice of Inquiry, Interstate Transportation of Gas for Others, 50 Fed. Reg. 114 (January 2, 1985); FERC Notice of Inquiry, Natural Gas Pipelines Ratemaking, Risk and Financial Implications after Partial Wellhead Decontrol, 50 Fed. Reg. 3801 (January 28, 1985).
[29] Charles G. Stalon, "Finding New Objectives for Natural Gas Pipeline Regulation," a paper presented to the Eighth Annual National Conference of Regulatory Attorneys (Hartford, Connecticut, May 13, 1985).
[30] FERC Notive of Proposed Rulemaking, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Docket No. Rm 85-1-000, 50 Fed. Reg. 24130 (June 7, 1985).

regulations: a simplified transportation program; provisions for take-or-pay buy-outs; optional, expedited certification procedures for new services when pipelines are willing to assume the risk of the venture; and a block-billing mechanism meant to preserve the benefits of "old" gas for existing firm customers and to mitigate price signal distortions that linger because of the continued regulation of the wellhead price of old gas.

The FERC issued its final rule and statement of policy in FERC Order 436 on October 9, 1985.[31] In the order, the FERC amended its regulation in three of the four parts mentioned above: transportation, take-or-pay, and optional, expedited certificates.[32]

For our purposes, the parts dealing with transportation and optional, expedited certificates are most important. The transportation provisions of the order create a simplified gas transportation program including blanket certificates and NGPA section 311 transportation, conditioned on the pipeline providing nondiscriminatory access for such transportation. The traditional gas sales and transportation options remain available to the pipelines and their customers under the existing FERC certificate program. This voluntary transportation program and the expedited certificate program pursuant to FERC Order 436 embody the current state of federal regulation regarding open access to interstate gas pipelines.

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[31] FERC Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Docket No. RM 85-1-000, 50 Fed. Reg. 42408 (October 18, 1985).

[32] The FERC merely reaffirmed its earlier policy statement regarding pipeline buy-outs of take-or-pay contracts and provided for expedited processing of producers' abandonment applications. The FERC did not adopt the resumption of prudence, "safe harbor" rules proposed in the NOPR. The block billing provisions of the NOPR were also not adopted in the final rule. Rather, the FERC issued a new NOPR requesting additional comments in a revised proposed rule which is designed to be phased-in beginning July 1, 1986.

"Access to the Bottleneck": The Status of Regulation in the Electric Industry

The current state of regulation concerning access to electric transmission is best understood in the context of the industry's legal history. The first statute affecting access to the electric transmission system is the Federal Power Act.

The Federal Power Act

The Federal Power Act was enacted in 1935 and provided a regulatory scheme at the federal level to fill the regulatory gap left by the 1927 Attleboro case.[33] In Attleboro, the United States Supreme Court struck down an attempt by a state commission to regulate the rates of a domestic utility selling wholesale power to an out-of-state distribution company. The Court reasoned that wholesale transactions were essentially national in character and that under the Commerce Clause state regulation of such sales was a direct burden on interstate commerce. Regulation of such interstate (read wholesale) transactions could only be delegated by federal law. At the time of Attleboro, no such federal act existed. Eventually, Congress filled this regulatory gap by enacting Part II of the Federal Power Act.[34] Thus, although the Federal Power Act and Natural Gas Act have many parallel provisions, the history leading up to their enactments is somewhat different.

Part II of the Federal Power Act, as originally enacted, did not provide the Federal Power Commission with the authority to mandate

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[33] Public Utilities Commission v. Attleboro Steam and Electric Co., 273 U.S. 83 (1927).

[34] 15 U.S.C. sec. 79 et seq. (1935). For a more thorough discussion of the origins of the Federal Power Act, see Jerry Pfeffer and William Lindsay, The Narragansett Doctrine: An Emerging Issue in Federal-State Regulation (Columbus, Ohio: The National Regulatory Research Institute, 1984). Also note that the Attleboro case created a regulatory gap for the gas industry as well. However, in the gas industry there was the additional concern of pipelines not having adequate supplies.

access to the transmission system. Further, unlike the Natural Gas Act, the Federal Power Act did not require FPC certification of other transmission facilities before they were built or transportation services before they are delivered. Rather, the Federal Power Act provided that tariffs for wholesale power transactions, including the wheeling of power, were to be filed at the Federal Power Commission before the transaction took place. This is an important distinction.

In enacting the Federal Power Act, Congress did not empower the FPC to order wheeling of power. Rather, Congress intended to rely on the voluntary action of the utilities to coordinate electric transmission facilities.[35]

Otter Tail Power

Over the next few decades, the electric utility industry grew, and because of economics of scale, the size of central power stations increased. As noted earlier, an industry structure developed which had many small publicly-owned power entities as isolated islands served by the transmission systems of privately-owned electric companies. Such an industry structure creates the potential for monopolization if the privately-owned utility refuses to wheel power over its transmission lines to the isolated utility.

In 1972 the United States Supreme Court heard such a case on appeal from the U.S. District Court of Minnesota.[36] The facts of the case as

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[35] There was, however, an interconnection provision that allowed the Commission to direct a public utility to connect its transmission facilities with the transmission facilities of another or to direct the sale of energy, when the Commission found it to be in the public interest. Federal Power Act, sec. 202(b). The Commission could not, however, compel the enlargement of generating facilities, nor compel a utility to sell power when to do so would impair its ability to render adequate service to its customers.
[36] Otter Tail Power Co. v. United States, 410 U.S. 359, reh. denied 411 U.S. 910 (1973); remanded, 360 F. Supp. 451, affd. 417 U.S. 901 (1974). The original U.S. District Court case is United States v. Otter Tail Power Company, 331 F. Supp. 54 (U.S.D.C. Minn., 1971).

determined by the District Court follow. At the time of the case, the Otter Tail Power Company's service area encompassed western Minnesota, northeastern South Dakota, and eastern North Dakota. The Otter Tail Power Company was an integrated system servicing 465 municipalities on its distribution system. Otter Tail provided retail service to each municipality pursuant to a franchise awarded to it by each municipality. By state law in each of the three states, the franchises awarded by the municipalities are non-exclusive and of a limited term. At the time of this case, the Minnesota Public Utilities Commission did not regulate gas and electric utilities. Gas and electric service regulation was established in Minnesota on April 12, 1974 and rate regulation became effective January 1, 1975.

The Otter Tail Power Company bought dump power from and engaged in wheeling for the Bureau of Reclamation. The Bureau marketed "cheap" power, generated from hydroelectric facilities along the Missouri River, to certain preference customers, including municipal electric systems. At the request of the Otter Tail Power Company, its contract with the Bureau of Reclamation for these wheeling services specifically exempted Otter Tail from any obligation to wheel power to municipalities that it had previously served at the retail level.

Several small towns, including Elbow Lake, Minnesota, attempted to set up their own municipally-own distribution system so that they could obtain power at wholesale or, in the alternative, receive wheeled hydro-electric power from the Bureau of Reclamation. The Elbow Lake municipal system acquired its own generating plant after the Otter Tail Power Company refused power at wholesale. When Elbow Lake sought stand-by power from Otter Tail, Otter Tail again refused. After this, Elbow Lake sought power from the Bureau of Reclamation and other sources. Each source was willing to provide the power, but could not because Otter Tail refused to wheel the power over its transmission lines.

At this point, it is worth recapping some of the more distinctive facts of the Otter Tail case. First, Otter Tail at the time had no exclusive franchise, granted by a state commission, to serve at retail.

Instead, Otter Tail had a non-exclusive franchise of limited term that was awarded by the municipalities and towns it served. Second, Otter Tail was a multistate utility that also wheeled power obtained at wholesale. Clearly, Otter Tail was in interstate commerce. Third, Otter Tail did not simply refuse to wheel power. It refused either to wheel or to supply wholesale power to the municipality, essentially foreclosing any possibility of the municipality forming a distribution system even if it bought all its power from Otter Tail.

The District Court held that the Otter Tail Power Company had a strategic dominance in the transmission of power at the subtransmission level and that it was not economically feasible or practical for a municipality to construct its own subtransmission lines to gain access to other power sources. Hence, these lines were essential facilities. The District Court found that Otter Tail refused to wheel power to newly formed municipal distribution systems and to towns desiring to form such systems. The District Court held that Otter Tail Power, by refusing either to sell at wholesale or to wheel power over its transmission system, intentionally acted to preserve its monopoly power over its retail market. Because the utility operated without an exclusive franchise from the customers of these municipalities, the court held that Otter Tail did not have a right to be free of competition. The Court applied the "bottleneck theory" of antitrust and held that it is an illegal restraint of trade for a party to foreclose potential competition by not allowing others the use of scarce, essential facilities. It held that, by its refusal either to sell at wholesale or to wheel power, Otter Tail prevented competition with a municipality from developing. The District Court held that Otter Tail monopolized interstate commerce in the retail distribution of electric power in violation of section 2 of the Sherman Antitrust Act.

The United States Supreme Court affirmed the District Court's decision.[37] First, the Supreme Court pointed out that the FPC was not empowered to mandate wheeling. And although Congress had rejected provisions empowering the FPC to mandate wheeling and instead relied on the voluntary action of utilities, the Court found that this fact was no basis for concluding that FPC regulation was intended to be a substitute for antitrust law. The Court stated that

> [r]epeals of the antitrust laws by implication from a regulatory statute are strongly disfavored, and have only been found in cases of plain repugnancy between the antitrust and regulatory provisions.... Activities which come under the jurisdiction of a regulatory agency nevertheless may be subject to scrutiny under the antitrust laws.[38]

Thus, Otter Tail stands for the legal proposition that the United States Courts could enforce the antitrust laws on electric utilities and compel wheeling when a violation of the antitrust laws was found to exist.

Next, the Supreme Court held that the District Court's decree, to the extent that it mandates an interconnection, presents no actual conflict with an order of the Federal Power Commission. The District Court's decree provided only that the District Court would retain jurisdiction as necessary or appropriate to carry out its decree. Since there was not an order by the Federal Power Commission denying an interconnection, only a potential conflict existed between the District Court's decree and a potential FPC order. Thus there was then no present concrete case or controversy for the Supreme Court to decide.

Until the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA), the courts were the sole entity that could compel wheeling. With the enactment of PURPA, however, the Federal Energy Regulatory Commission was empowered to mandate wheeling under certain

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[37] See Otter Tail Power Co. v. United States, 410 U.S. 366 (1973). The U.S. Supreme Court vacated the District Court on its holding on the Noerr doctrine; however, this doctrine is not a concern in this report.
[38] Id. at pp. 372-375.

very limited circumstances as specified in sections 203 and 204 of that law.[39] PURPA section 203 provides that any electric utility or federal power agency may apply to the FERC for wheeling services. The FERC may issue an order (pursuant to section 203(a)) mandating wheeling if, after public notice and hearing, it finds that an order mandating wheeling (1) would be in the public interest; (2) would conserve a significant amount of energy, significantly promote the efficient use of facilities and resources, or improve the reliability of any electric utility system to which the order applies; and (3) would meet the requirements of PURPA section 204, which are discussed below.

Section 203 also provides that any electric utility or federal power marketing agency, which purchases electricity for resale from any other electric utility, may apply to the FERC for an order requiring such other electric utility to provide transmission services to the applicant. The FERC may issue such an order (pursuant to section 203(b)) if, after notice and hearing, it determines that (1) the electric utility from whom the transmission service is sought has given "actual or constructive notice"[40] that it is unwilling or unable to provide electric service to the applicant, and the applicant has requested transmission service, and (2) the order meets the requirements of PURPA section 204.

The key requirements of PURPA section 204 are that no wheeling order is to be issued by the FERC unless it determines that the order (1) is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility affected by the order, (2) will not place an undue burden on an electric utility affected by the order, and (3) will not unreasonably impair the reliability of any electric

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[39] These provisions of PURPA amended Part II of the Federal Power Act by adding sections 211 and 212 to the FPA.

[40] Constructive notice here would appear to mean notice that is imputed, by law, to be given because of the conduct of the electric utility from whom wheeling is sought.

utility affected by the order, to render adequate service to its customers.

Even if all the provisions listed above are met, the FERC is not permitted to issue an order under section 203(a) unless it determines that the order would reasonably preserve existing competitive relationships. Further, no order that mandates wheeling may be issued if it would be inconsistent with state laws governing the retail marketing areas of electric utilities or if the order would provide for transmission of electricity to an ultimate customer.

Enactment of PURPA did not supplant the authority of the state and federal courts to mandate wheeling when a violation of the antitrust laws occurs. Rather, the enactment of PURPA supplemented Otter Tail and the associated line of cases. This was made clear in the legislative history of the law, which stated

> ... with regard to certain authorities to order interconnections and wheeling under Title II ..., it is not intended that the courts defer actions arising under the antitrust laws pending a resolution of such matters by the [Commission] ... Courts have jurisdiction to proceed with antitrust cases without deferring to the Commission for the exercise of primary jurisdiction.[41]

Thus, while the FERC has been given a new authority--the power to mandate wheeling--that authority is limited to a very narrow set of circumstances and it is not exclusive. The courts' authority to enforce the antitrust laws is left undisturbed.

In a post-PURPA court case, New York State Electric & Gas Corp. v. FERC,[42] the Second Circuit Court of Appeals had occasion to examine the new authority of FERC to order wheeling. The court concluded that, while Congress intended this new power to serve as a tool for enhancing competition by facilitating bulk purchases of power, Congress also

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[41] See House Conference Report No. 95-1750, 95th Cong., 2d Sess. 63, 1978 U.S. Code Cong. and Ad. News 7802.

[42] New York State Electric & Gas Corporation v. Federal Energy Regulatory Commission, 638 F.2d 388 (2d.Cir. 1980).

intended that the FERC power to order wheeling be stringently limited. This would safeguard the voluntarism of the wheeling arrangement to the greatest extent possible while assuring all persons that they would be treated fairly and compensated fully if they were compelled to provide wheeling involuntarily.[43] Because of this finding, the court prevented the FERC from modifying a contract for transmission services because the effect of the modification would have been to compel the utility to wheel power involuntarily.

In another similar case, the Fifth Circuit Court of Appeals struck down a FERC order directing a utility to file a single tariff articulating the company's wheeling policy.[44] The filing of such a tariff would have been binding on the utility and would have obligated it to offer wheeling to all parties indiscriminately. Otherwise, a customer refused transmission services could have petitioned to find that the FERC policy was unduly discriminatory. A common carrier status would have been imposed on the utility if it could not make individualized decisions in particular cases as to whether and on what terms to serve.[45] The court found that the FERC order would have in effect imposed common carrier status upon the utility.[46]

The court held that the Federal Power Act did not give the FERC the authority to make an electric utility into a common carrier and that under the Federal Power Act the FERC could not require wheeling even on a reasonable request. The court ruled that the FERC could not require the utilities to bootstrap themselves into common-carrier status by requiring them to file rates for voluntary service.[47] Further, the FERC

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[43] Id., at p. 402.
[44] Florida Power & Light Co. v. Federal Energy Regulatory Commission, 660 F.2d 668 (5th Cir. 1981).
[45] Id., at p. 674.
[46] Id., at p. 676.
[47] Id., at p. 673, citing Richmond Power & Light of Richmond, Indiana v. Federal Energy Regulatory Commission, 574 F.2d 610, 620 (D.C. Cir. 1978).

could not overstep its authority and require involuntary wheeling, aside from compliance with PURPA sections 203 and 204.

In both of these cases, courts "have rejected ingenious arguments which would have established the [FERC] authority to require wheeling by indirect means."[48] Thus, the courts have made it clear that the FERC authority to compel wheeling is limited by the strigent requirements laid out in PURPA.

FERC Notices of Inquiry[49]

Recently, the FERC has issued two notices of inquiry (NOIs) regarding its policies toward wholesale electricity transactions and transmission services. In its Phase-I NOI, the FERC sought to evaluate its present policies toward those transactions and services to determine whether the policies promote or impede efficiency in electricity markets, and whether alternatives or revisions to its present policies would further promote efficiency. In its Phase-II NOI, the FERC explored its regulation of wholesale electric requirements service with a focus on the pricing and risk allocation of the services.

The FERC has received comments and held conferences on these two NOIs. As of this writing, no further action has been taken by the Commission. Indeed, none is expected for some time on transmission pricing because of the difficulty and complexity of electricity transmission.[50]

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[48] Id.
[49] FERC Notice of Inquiry, Regulation of Electricity Sales-for-Resale and Transmission Service, Docket No. RM85-17-000 (Phases I and II), 31 FERC 61,228 and 61,376 (May 30 and June 28, 1985, respectively).
[50] See "FERC Commissioner, Others Say Transmission Issues to Take Years to Resolve," Electric Utility Week, March 3, 1986, pp. 14-15.

The Federal Power Act and the Natural Gas Act Compared

The Federal Power Act and the Natural Gas Act are both statutes enacted to protect the public interest. The two statutes have a somewhat different history behind them. Nevertheless, it is well established in the law that the Federal Power Act and the Natural Gas Act are cut from the same cloth and that similar provisions between the two acts are to be read in pari materia, i.e., to be construed together. The Federal Power Act and Natural Gas Act share terms such as "public convenience and necessity," "just and reasonable," and "public interest." This is not surprising because both these two laws have the Interstate Commerce Act as their basic model.

The Similarities

The premier law review article comparing the Federal Power and Natural Gas Acts' provisions that might be applied to transmission services is Harvey Reiter's "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts." Reiter points out that both statutes have (1) prohibitions against unreasonable rates, charges and classifications, (2) prohibitions against undue preferences or discrimination in rates or services, (3) rate schedule filing requirements, and (4) a grant of authority to regulators to prescribe systems of accounts and to conduct inspections of accounts and records.[51] Further, despite the previously mentioned differences, both statutes have a similar legislative history when dealing with the concept of carriage. Congress rejected similar common carriage proposals in the Federal Power and Natural Gas Acts. Instead, Congress intended something different. As Reiter observed, the public utility form of the Federal Power and Natural Gas Acts distinguishes these acts from the private carrier regulation of the

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[51] Reiter, p. 37.

Interstate Commerce Commission. What is envisioned in these two laws is a contract carriage scheme of regulation.[52]

The Two Obstacles

Reiter, before going on to his theme that the Federal Power Act and the Natural Gas Act contain within them statutory provisions to provide open access to gas and electric transmission, finds it necessary to argue for the removal of two obstacles in his path: the New York State Energy & Gas and Florida Power and Light cases discussed earlier. Reiter asserts that the two cases were wrongly decided because they inherently suggest that distinctions can be drawn both (1) between the commission jurisdiction over rates and its jurisdiction over services, and (2) between transmission service and sales for resale. Reiter then asserts and attempts to prove that such distinctions are not logically tenable.[53]

The Second and the Fifth Circuits did not explicitly make such distinctions, however. Instead, both decisions appear to be premised on the grounds of a narrow interpretation of explicit statutory provisions. Both the New York State Energy and Gas and Florida Power and Light decisions hold that Congress rejected common carrier status for electric utilities and that the FERC cannot do indirectly what it is prohibited from doing directly, i.e., transforming the electric utilities from private to common carriers.[54] Both cases also hold that if a FERC decision would in effect compel wheeling then the Commission must follow

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[52] Id. at pp. 35-37.
[53] Id. at pp. 42-45.
[54] Florida Power and Light v. Federal Energy Regulatory Commission, 660 F.2d at pp. 672-676; New York State Electric & Gas Corporation v. Federal Energy Regulatory Commission, 638 F.2nd at pp. 401-403.

the explicit statutory prerequisites of PURPA sections 203 and 204 before it can mandate wheeling.[55]

Reiter criticizes the courts for basing their decisions on Congress's rejection of common carrier status for the utilities. Reiter asserts that there is a significant distinction between the indiscriminate, absolute obligations of common carrier status and the qualified rights of contract carriers. He bases this assertion on two cases. The first of these is Richmond Power & Light v. FERC.[56] In the Richmond case, the D.C. Circuit, in dicta, held open the possibility that relief is available from unduly discriminatory or unreasonably anticompetitive refusals to wheel power. The second case Reiter relies on, Central Iowa Power Cooperative v. FERC,[57] does not discuss FERC authority to compel wheeling. However, it does involve undue discrimination. This case concerned smaller utilities that wished to join a power pool from which they were excluded. The FERC ordered the pool to be expanded. While the Commission lacked authority to force the utilities to set up a pool, once established the pool agreement had to meet the standards of the Federal Power Act, including the prohibition against undue discrimination. Reiter argues that Central Iowa is significant because it (1)

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[55] Florida Power and Light Company v. Federal Energy Regulatory Commission, 660 F.2d at 678; New York State Electric & Gas Corporation v. Federal Energy Regulatory Commission 638 F.2d at 400. Reiter, in a footnote of his article, argues that it is unclear whether the court in New York State Electric and Gas was relying upon the legislative history of PURPA merely to aid in its construction of section 206 or whether the court was holding that PURPA sections 203 and 204 limit the Commission's preexisting authority under section 206. Reiter argues that, to the extent that the court's opinion suggests the latter, it is of dubious validity because repeals by implication of previously enacted laws are disfavored. Further, Retier contends that PURPA section 4(2) demonstrates Congress's intent that PURPA be strictly neutral and not add to or subtract from the authorities available under the Federal Power Act. Reiter, at p. 24, footnote 119.

[56] Richmond Power & Light of Richmond, Indiana v. Federal Energy Regulatory Commission, 574 F.2d 610 (D.C. Cir. 1978); Reiter, at pp. 49-50.

[57] Central Iowa Cooperative v. Federal Energy Regulatory Commission, 660 F.2d 1159 (D.C. Cir. 1979); Reiter at pp. 47-50.

supports FERC authority to remedy undue discrimination by extending services to those previously excluded, (2) established the principle that this power exists even where the FERC has no authority to compel the utility to provide the service initially, and (3) draws the proper distinction between a voluntary initial undertaking and the activity once undertaken that then comes under the full regulatory powers of the FERC.[58] Reiter asserts that

> because the claim of undue discrimination is likely to be the excluded customer's most potent claim to pipeline or transmission access, the breadth of Commission authority to remedy undue discrimination is a critical issue.[59]

Whether or not one agrees with Reiter's analysis here, his conclusion on the importance of FERC authority to remedy undue discrimination once discrimination has occurred has proven to be correct for the gas industry.

There are, however, some problems with the cases that Reiter relies on for his analysis of the electric industry. The passages cited from the Richmond case are dicta. In other words, the passages are not essential to the holding of the case and cannot be regarded as creating a legal precedent. Further, the Richmond case was decided before PURPA was enacted so that the court did not examine statutory provisions of PURPA sections 203 and 204. The Central Iowa case, as Reiter himself points out, does not concern FERC authority to compel wheeling. Here too, the court did not need to look to the explicit language of PURPA sections 203 and 204.

The underlying problem in Reiter's analysis is the explicit language of PURPA sections 203 and 204, which set out the very stringent preconditions that must be met before the FERC can issue an order to compel wheeling. Even though PURPA is to be considered neutral concerning FERC authority to correct anticompetitive behavior, courts

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[58] Reiter, at p. 50.
[59] Id.

look to PURPA sections 203 and 204 as an embodiment of Congress's intent on the breadth of FERC authority to compel wheeling. Thus, a court would be hard pressed to ignore explicit statutory provisions such as PURPA sections 203 and 204. To do so would be engaging in judicial legislation. Also, it appears that the courts view the ability to compel wheeling under PURPA sections 203 and 204 as a limited expression of FERC authority, to be strictly construed so as to encourage the voluntary nature of wheeling arrangements as was originally intended by Congress under the Federal Power Act.[60]

Statutory Relief under a Contract Carriage Scheme

The heart of the Reiter article is the author's proposal that access to gas transportation and electric transmission facilities can be ordered by the FERC in a manner consistent with contract carriage obligations. His argument proceeds as follows: the Otter Tail Power case established that "the essential facilities" doctrine of antitrust applies to bottleneck facilities, such as electric transmission and gas pipelines facilities. The "essential facilities" doctrine protects the public interest by preserving competitive opportunities.[61]

Reiter argues that the "essential facilities" doctrine of antitrust should be used as an initial (threshold) test for Natural Gas Act and Federal Power Act claims for access. He would, however, limit these claims by other public interest claims entitled to protection under the acts, such as recognizing the special rights of high-priority gas end users.[62]

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[60] However, it is worth reemphasizing that, according to the statutory provisions of PURPA, FERC authority under other provisions of law (including the Federal Power Act and the Natural Gas Act) respecting anticompetitive acts or practices is unaffected by PURPA. See PURPA sec. 4(2). The Conference Report states that the conferees intended that the provisions of PURPA be strictly neutral and not add to or subtract from authorities contained in other provisions of law.
[61] Reiter, at pp. 62-64.
[62] Id. at pp. 64-66.

Reiter sets out four statutory avenues for relief from a denial of access. One avenue would be a claim that a denial of access or an offer of access with an unreasonably high rate or unreasonable conditions attached is an unreasonable condition of service prohibited by section 4(a) of the Natural Gas Act and section 205(a) of the Federal Power Act. He notes that such an access claim might be made if a pipeline or utility refuses to unbundle its transportation or transmission services from its wholesale sales.[63]

The second avenue of statutory relief identified by Reiter is the obligation on the part of the utilities to operate their business in a prudent, reasonable, or efficient manner. Reiter suggests that if pipelines or electric utilities underutilize their transmission capacities a claim of imprudence might be possible should the pipeline or electric utility have failed to seek the business of or have denied access to customers willing to purchase transmission services. Reiter points out that a utility could have a legitimate defense to such a charge of imprudence.[64] One such defense, for example, might be that the capacity remained unused in order to protect the reliability of the customer service.

The third and fourth of the statutory avenues of relief identified by Reiter in his article were subsequently used as a statutory basis for FERC Order 436. The third avenue was the statutory protection against undue discrimination found in the Natural Gas and Federal Power Acts. According to Reiter, its most significant value is its applicability where competitors are denied service offered to others. Further the "undue" in undue discrimination allows other public interest factors to be taken into account. Such limitations should help distinguish this remedy from common carriage.[65]

Looking back with the benefit of "20-20 hindsight," the author notes that Reiter's analysis of this remedy has proven to be somewhat

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[63] Id. at pp. 66-67.
[64] Id. at pp. 74-76.
[65] Id. at pp. 68-69.

prophetic. As noted earlier the D.C. Circuit Court in Maryland People's Counsel I & II overturned the FERC special market and blanket certificate programs because they were unduly discriminatory. The FERC, in response to the court's decision, issued Order 436, which created an optional (voluntary) transportation program in which participating pipelines act as contract carriers providing nondiscriminatory open access on a first-come, first-served basis. Indeed, two of the three statutory provisions on which the FERC based its authority to apply the nondiscriminatory open access condition to interstate gas transportation were sections 4 and 5 of the Natural Gas Act. These provisions prohibit unduly discriminatory or preferential practices by natural gas companies. The FERC, in issuing Order 436, was careful to distinguish its new voluntary nondiscriminatory carriage from common carrier obligations. The Commission states that a principal attribute of common carrier regulation is its mandatory nature. For its Order 436 program, it is not mandatory that the pipelines participate.[66]

The fourth avenue of statutory relief (where Reiter has also proven to somewhat prophetic) concerns the use of the FERC certification authority. As Reiter points out, the FERC has broad powers to grant certification for the construction and operation of pipeline facilities upon such terms and conditions as may be required by the public convenience and necessity.[67] And, as also noted by Reiter, the FERC has no comparable certification authority in the electric industry other than the power to condition licenses for hydroelectric projects.[68] Reiter argues in favor of conditioning the approval of pipeline certification amendments and of new pipeline facilities. He contends that the certification process should be used within a contract carriage context, as a form for addressing access issues.[69]

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[66] FERC Order 436, 50 Fed. Reg. 42427-8 (October 18, 1983).
[67] Reiter, at p. 69.
[68] Id. at pp. 69-70.
[69] Id. at pp. 72-73.

The FERC, in Order 436, uses section 7 of the Natural Gas Act as its third statutory basis of authority to apply the nondiscriminatory access condition to interstate pipelines. The Commission cites section 7(e) of the Natural Gas Act, which states, in pertinent part, that the FERC

> shall have the power to attach to the issuance of the certificate and to the exercise of the rights thereunder such reasonable terms and conditions as the public convenience and necessity may require.[70]

The FERC has interpreted its certification authority as allowing it to provide self-implementing blanket transportation authorization subject to an express nondiscriminatory access condition. This condition requires any interstate or intrastate pipeline that provides any transportation service under the certificate to provide the same service for all shippers willing to pay the applicable tariff rate for the service. The transportation service must be available without discrimination (1) in the quality of service provided, (2) in the categories, price, or volumes of gas transported, and (3) by customer class.[71]

In addition, the FERC used its section 7 certification powers to create a new optional expedited certificate for new services and a conditionally pre-approved abandonment authorization. The pre-approved abandonment authorizations are granted only if the customer has an alternate provider of service. The expedited certificates for new services are available only to those pipelines providing nondiscriminatory services. In addition, such a pipeline must assume the full risk of undertaking the new venture. The certificates are nonexclusive; a

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[70] FERC Order 436, at p. 42410.
[71] Ibid., p. 42426 (October 18, 1985). Self-implementing transportation authorizations under section 311 of the Natural Gas Policy Act, are available subject to the same express nondiscriminatory access condition.

pipeline granted the certificate may (and often will) face competition.[72] Thus, the expedited certification for new service could help to enhance the competitiveness of those pipelines providing nondiscriminatory transportation services.

Reiter identified three additional non-NGA and non-FPA vehicles for addressing access claims to electric or gas transmission. As mentioned, two are to bring antitrust litigation based on the essential facilities doctrine, and to compel wheeling pursuant to PURPA sections 203 and 204. The third is wheeling ordered as a condition to the granting of a nuclear power plant license (the granting of a license by the Nuclear Regulatory Commission is subject to an antitrust review under section 105(c) of the Atomic Energy Act.) According to Reiter, the previously cited statutory provisions of the Natural Gas Act and Federal Power Act are more likely to be important vehicles for addressing access claims. For the gas industry, the prediction has proven to be true.

Analysis and Discussion

The industry structure and technology interact with the law concerning third-party access to transmission facilities in the electric and gas industries, both creating new law and influencing the structure and technologies of these industries.

The Effect of Industry Structure and Technology on the Law

For gas pipelines, the industry structure and technology make possible regulatory changes that would allow third-party access to the transmission system. With many independent producers and buyers, and a technology that allows for control of the transmission path of gas, a workably competitive market may emerge.

[72] Ibid., p. 42410.

This potential for a competitive market itself creates pressure for such a market to be created. This is particularly true during a period of oversupply. At that time, end users will demand and many producers will be willing to produce at lower prices. If a pipeline does not allow access by third-parties seeking a lower price, such customers can seek such service from another pipeline if one is available. (Earlier in this report, it was stated that service from another pipeline is available more times than not.)

The pressure to create a competitive market affects the law. Competitive pressures caused pipelines to transport gas for others from producers to end users. The creation of special marketing and blanket certificate programs were ad hoc legal responses to competitive pressures.

When the pipelines implemented their special marketing and blanket certificate programs, they did so in a way that would segment their markets. The pipelines attempted to make those programs available only to those customers with elastic demand and not to those customers whose demand is inelastic. In an unregulated industry this type of discrimination is usually prevented because reselling can occur, which tends to enforce the economic law of one price. Reselling is difficult, however, in the case of regulated utilities so that price discrimination can and does persist. In addition, a reseller of a regulated product runs the risk of himself becoming a regulated utility in many jurisdictions, another reason why price discrimination persists. Because of the oversupply situation, all gas customers, including those with inelastic demand, were seeking gas at a lower price. The Maryland People's Counsel challenged the discriminatory nature of the pipeline's special marketing and blanket certificate programs and won. As a result the FERC issued Order 436.

It is likely that the structure and technology of the gas industry will continue to impose competitive pressure on the pipelines to voluntarily accept the open access available under Order 436. A pipeline otherwise may find itself undercut by competing pipelines capable of serving the same market and offering nondiscriminatory service. Because pipelines offering nondiscriminatory service are allowed an expedited certificate, they can move swiftly to undercut pipelines offering traditional merchant service and thus they may capture an increased market share.

In the electric utility industry, the industry structure and technology are not, at least yet, appropriate for third-party access to the transmission system. While there are numerous small qualifying facilities on line and forecasted to come on line, most power is still produced at central power generating stations that are owned and operated by vertically integrated companies. The addition of new, independent producers can create some competitive pressures. The transmission technology, however, does not easily lend itself to a more competitive market. A generator trying to wheel its power to an end user will likely affect transmission systems other than those involved in the wheeling transaction. Because other systems affected by transfers of power may be uncompensated and because reliability may be affected, the FERC and the courts are likely to move toward a more competitive environment with greater caution than they have in the gas pipeline industry.

The Effect of the Law on Industry Structure and Technology

For the gas pipeline industry, the outcome of Order 436 is not yet clear. Competition, however, is beginning to spread throughout the industry. Some pipelines are applying for nondiscriminatory carrier status; gas brokerage firms are now publishing spot market prices for gas; and local distribution companies are reexamining their gas purchasing practices in light of lower gas prices.

As mentioned earlier, pipelines that are nondiscriminatory carriers under Order 436 can provide service under self-implementing expedited certificates. The rules implementing these expedited certifications provide a rebuttable presumption that the proposed service is or will be consistent with the public convenience and necessity if the applicant complies fully with the regulatory requirements. These include a requirement that the applicant must assume the full economic risks of the project and not shift costs. Pipelines that provide nondiscriminatory contract service are given an opportunity to enter and to leave markets quickly, thus creating opportunities for competition where none previously existed. Gas pipelines providing traditional merchant services must contend with the traditional, usually slow, certification process to respond to these competitive pressures. These pipelines might find that it behooves them to switch and become nondiscriminatory carriers rather than lose their markets. Thus, the expedited certification process is intended to encourage pipelines to engage in nondiscriminatory carriage. The new FERC certificates may result in competitive forces to change the gas industry structure.

What will the new gas industry look like? Such soothsaying is dangerous, but one might speculate that several years from now a majority (rather than the current minority) of pipelines will offer transportation services to all on a nondiscriminatory basis. Gas brokerage firms may become more common, perhaps engaging in specialized marketing for particular types of customers. The types of gas service readily available may become more varied, with time-of-use, reliability and requirements options, which previously did not exist. Gas pipelines may still, however, be the principal brokers of gas. After an initial shake-up period, pipelines may find that their own previous experiences as buyers or sellers of gas give them a comparative advantage.[73] All of these changes are indicative of the greater uncertainty the natural gas industry will face in the future.

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[73] For an interesting article in which a gas utility executive forecaststhe outlines of the gas industry that will emerge in the future, see Virod K. Dar, "The Natural Gas Industry: Goetterdaemmerung and the Phoenix," Public Utilities Fortnightly, January 23, 1986, pp. 26-29.

For the electric utility industry, sections 203 and 204 of the Public Utility Policies Act severely limited the authority of the FERC to compel wheeling. The FERC has begun to explore alternatives that give electric utility systems an incentive to transmit power for others voluntarily. The most recent examples are the Commission's Notices of Inquiry, discussed earlier, and its Southwestern Bulk Power Exchange Experiment.

The FERC efforts to remove the legal impediments to wheeling are likely to evolve more slowly and carefully than its natural gas transportation program for several reasons. First, the Commission faces the explicit language of PURPA sections 203 and 204 which embody the Congressional intent that FERC authority to compel wheeling be strictly limited. Because of the explicit language in PURPA, the FERC is unlikely to step out of the statutory bounds and engage in a rulemaking parallel to FERC Order 436. While the Federal Power Act and Natural Gas Act are in pari materia, intervening statutes such as PURPA can cause a separate statutory interpretation to be reached on essentially similar issues. Such appears to be the case here.

Further, even if the FERC were to decide to issue for the electric industry an order parallel to Order 436, such a regulation would not be very effective. The Federal Power Act does not contain the same certification provisions that are found in the Natural Gas Act. The FERC, therefore, may find it difficult at best to encourage voluntary, nondiscriminatory carriage where voluntary wheeling is not already occurring.

A third reason that the FERC is likely to be cautious is the complexity of the underlying technology of electric utility transmission. As noted earlier, electricity cannot be readily controlled to any great degree to follow a contract path.

What regulatory procedures might the FERC now use to encourage further wheeling transactions? First, it can continue to examine its options for encouraging wheeling in its current NOIs. Second, the FERC may wish to reexamine its authority to compel wheeling under PURPA sections 203 and 204. As noted by John O'Sullivan, then FERC Chief

Advisory Counsel, the current procedures under those sections are too lengthy and expensive and are limited with respect to who can actually seek wheeling services.[74] The FERC may wish to consider initiating a rulemaking to clarify how the procedures under PURPA sections 203 and 204 actually work. As Tiano and Zimmer point out, there are presently no regulations to set out wheeling guidelines or to facilitate compliance with the complex preconditions mandated by PURPA. As a matter of regulatory efficiency, it would probably be useful in the long run to promulgate regulations rather than continue with the case-by-case approach used to date.[75]

Further, the FERC might engage in a rulemaking to encourage (and when necessary to mandate) wheeling to the fullest extent possible in light of Maryland People's Counsel II. That case, discussed earlier, appears to have expanded the FERC obligation to enforce the antitrust laws. The argument as it applies here goes like this. It is, of course, now well established that the FERC must consider antitrust and anticompetitive issues as part of the public interest standard under the Federal Power Act. This serves the important function of establishing a first line of defense against those practices that later might be the subject of antitrust proceedings.[76] The Otter Tail Power case shows that an unreasonable denial of access to essential facilities, such as transmission lines, can lead to an antitrust violation. PURPA sections 203 and 204 empower the FERC, under certain very limited circumstances, to order wheeling, and so to correct such anticompetitive behavior. Although the FERC is not bound by the dictates of antitrust laws, antitrust concepts are intricately involved in the public interest

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[74] The testimony of John D. O'Sullivan before the House Energy and Commerce Subcommittee on Energy Conversation and Power on the Utility Role in Cogeneration, June 3, 1981, as cited in Tiano and Zimmer, pp. 101-102.
[75] Tiano and Zimmer, p. 102.
[76] Gulf States Utilities Co. v. FPC, 411 U.S. 747, 760.

concept and the FERC is obligated to consider those issues in its proceedings,[77] even if no party raises them.[78]

As noted by Nowak and Leitch, Maryland People's Counsel II required the FERC to consider possible anticompetitive practices under the blanket certificate program before the orders establishing that program was promulgated.[79] They further suggest that the court in Maryland People's Counsel II expanded the FERC duty to consider antitrust policies in the context of its decisions. Rather than just being neutral, the FERC must now more actively promote antitrust policies by expressly prohibiting potential anticompetitive behavior or articulating sound reasons for failing to do so.[80]

Given the holding in Maryland People's Counsel II, the FERC, if it sees fit, might use the occasion of a rulemaking to establish procedures for PURPA sections 203 and 204 hearings to discourage unreasonable refusal to wheel. This rulemaking could have as its aim maximizing access to transmission facilities, while protecting both the utilities' interest in being compensated for economic costs placed upon their systems by others and everyone's interest in a reliable electric service. Striking the proper balance would be difficult, but such a rulemaking could supplement and give a needed added dimension to the FERC Phase I Notice of Inquiry concerning transmission services.[81]

Other more radical actions might allow greater access to electric transmission facilities, but they would require industry restructuring. Such restructuring will not occur without action by Congress or the courts.

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[77] Maryland People's Counsel II, at p. 786.
[78] Id.
[79] Nowak and Leitch, p. 272.
[80] Id. at p. 274.
[81] While Phase I of the FERC Notice of Inquiry on Regulation of Electricity Sale-for-Resale and Transmission Services does ask whether transmission access is problem, it does not seek a solution should the problem exist.

Conclusions

The key points on the current law affecting access to transmission facilities in the electric and gas utility industries are as follows. For the electric utility industry, the explicit language of PURPA sections 203 and 204 strictly limits the authority of the FERC to compel wheeling on behalf of electric utilities or federal power marketing agencies. The provisions of section 203(a) and (b) would not, on their face, appear to include cogenerators. Nonetheless, the definition of a public utility contained within PURPA might possibly be construed to include a qualifying cogeneration facility as a "person" or "corporation which sells electric energy." The FERC, however, has not thus far adopted such a construction.[82] Even if the restrictive conditions of PURPA sections 203 and 204 are met, section 203 prohibits the FERC from issuing an order mandating wheeling that provides for the transmission of electricity directly to an ultimate customer. In other words, a large industrial customer cannot have power directly wheeled to it pursuant to a FERC order. However, if the wheeling were intrastate and involved only one utility, then the wheeling might not involve a sale at wholesale in interstate commerce. Such a wheeling transaction might come under possible state regulatory authority to mandate wheeling, although this has not been tested in the courts.

Besides the limited statutory authority of the FERC and the possible regulatory authority of the state public utility commissions, Otter Tail makes clear that the federal courts have judicial authority to mandate wheeling when a violation of the antitrust laws is found. The holding of Otter Tail, however, is not very helpful. The holding of the case, when narrowly construed, merely supports that a utility must either wheel or sell wholesale power to a requirements customer. So long as a utility operates in an area where a state public service commission grants exclusive service area franchises, there would be

[82] Tiano and Zimmer, p. 103.

little or no incentive for a utility not to sell wholesale power to a requirements customer. The lower federal courts, however, are continuing to develop this area of antitrust litigation. But, a thorough legal review of the antitrust decisions of the federal courts, concerning mandatory wheeling, is beyond the scope of this paper.

The Natural Gas Act and PURPA provide the FERC with somewhat more flexibility in devising programs to encourage access than do the corresponding electricity legislation. In particular, FERC Order 436 provides pipelines with the option of providing voluntary, nondiscriminatory contract carriage. Further, pipelines providing nondiscriminatory, open access can take advantage of an expedited certification process to quickly enter and exit gas markets. Pipelines are thus being given the opportunity to abandon their traditional merchant service and provide transportation service in its stead.

Local distribution companies with more than one pipeline supplier may wish to take advantage of transportation services available from pipelines offering voluntary, nondiscriminatory contract carriage. A local distribution company can, to the extent that it believes it is prudent to do so, go out into the field to acquire gas directly from a producer; or, to the extent that it needs to assure a firm source of supply is always available, a local distributor may choose to continue to purchase gas from its traditional pipeline supplier.

Large industrial customers may be tempted to bypass their local distributor if they can acquire cheaper gas from a producer. Such bypass might occur if the local distribution company refuses or is prohibited from offering transportation services to its customers. By denying a certificate of convenience and necessity a state commission may be able to prevent the construction of an intrastate pipeline that would allow a large industrial customer to bypass its local distribution company. A state commission, however, may be preempted from such an action if the construction is by an interstate pipeline offering open access under the Natural Gas Act section 7 expedited certificates for new services (including construction and operation of facilities). Such issues have yet to be resolved.

The law concerning access to electric transmission and natural gas transportation facilities is currently in a state of flux. In the author's opinion, the difference in the structures and technologies of the electric and gas industries should be recognized by policy makers. Regulators should fit the law separately to deal with the problems of "access to the bottleneck" for each industry, while remembering that the law cannot rework the underlying technologies. While the initial enabling statutes--the Natural Gas Act and the Federal Power Act--are *in pari materia*, the electric and gas industries are at best fraternal twins. Solutions for one industry will not necessarily translate into solutions for the other.

PRICE DISCRIMINATION LIMITS

AND

THE LOSS OF LOAD BY GAS UTILITIES

by Daniel Z. Czamanski
Technion - Israel Institute of Technology

Introduction

A recent expression of concern by Delaware Public Service Commissioner Joshua Twilley[1] is suggestive of the issues that occupy Public Utility Commissions (PUCs) in relation to the ongoing changes in the gas industry. The continuing decline in the prices of fuel oil and propane led to a decision by the Delaware PUC to accept a request by Delmarva Power and Light Co. to buy gas from its pipeline supplier, Transcontinental Gas Pipe Line Corp., under a special arrangement. In return for the commitment to sell the gas only to industrial customers with multi-fuel capacity, the price of the gas was set at $2.90 per mcf, well below the normal rate of $3.72 per mcf. Delmarva claimed before the PUC that not accepting this special deal would lead to a loss of a third of its commercial-industrial load, or as much as 15 percent of its total load.

In effect, state regulatory powers have been bypassed, in Commissioner Twilley's view, and are likely to be bypassed in the future. According to the Commissioner, the PUC is "impotent to deal with the gas problem..."[2] In effect, the gas pipelines are setting conditions on the sale of gas and "controlling the market opportunity and distribution of its gas..."[3] The emerging situation represents a de facto deregulation of the industrial load. In light of the growing

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[1] See "Skidding Oil Prices Put Strain on State PUC's Ability to Meet Mandates," Inside F.E.R.C., March 10, 1986, p. 8.

[2] Ibid.

[3] Ibid.

competition from substitute energy forms, is there any reason that the traditional monopoly franchise of gas distributors over the sale of gas to industrial customers be continued?

Whether the existing franchise monopoly ought to be retained depends, in part, on the stand-alone cost of serving each customer class. Such considerations are important, especially in the long-run. In the short-run it is not possible to ignore issues of long-standing arrangements that have affected technological choices and the way business has been and is being conducted. In today's environment it is important to know the extent to which industrial customers need to receive price breaks and the extent to which such breaks burden residential and commercial customers.

Some view the current situation as even more complex than is suggested by the above. In addition to competition for industrial customers with multi-fuel capacity, there exists the possibility that industrial customers, or large commercial or institutional consumers, or even groups of residential customers will decide to buy cheap gas by bypassing the local distribution system. Potentially, gas-on-gas competition includes a much larger group of customers than just industrials. (Hereafter the entire load that is threatening to leave the utility will be called the industrial load). As a result, state PUCs express some concern over the possibility that some natural gas distributors will experience a "death spiral." Such a process consists of a series of decreases in consumption levels caused by, and causing in turn, price increases.

The gravity of such a scenario stems from the possible future necessity to rely on foreign oil supplies during periods marked by energy shortages, while domestic gas supplies are unavailable because of undeveloped, or underdeveloped, infrastructure for the exploitation and distribution of domestic gas supplies. Less threatening possibilities include the need to consume available expensive imported oil or gas, or simply limiting the use of domestic gas to residential consumption. In the absence of PUC action, a most likely scenario from among the above might consist of an ever declining industrial load leading to ever smaller gas distribution utilities.

The market conditions and the regulatory environment today are a direct outcome of a long period during which energy policy reacted to short term concerns. The initial impetus to the variety of recent changes is associated with the energy market disequilibrium of the 1970s. The gas industry has undergone periods of excess demand caused by a massive switchover from oil and insufficient productive gas capacity, the need to curtail consumption in the face of inflexible price ceilings, and more recently a period of excess supply due to a complex set of circumstances. Since the 1970s, a number of broad energy policy initiatives at the federal level and a series of state PUC actions were designed and implemented to solve emerging problems in an incremental fashion. The current discussion of policy initiatives needs to be framed in the context of current conditions in energy markets and those that are likely to emerge in the future. The use of subsidized prices to prevent the loss of industrial load must be examined not only in terms of the short-term expected results, but also in terms of longer-term issues.

This paper is concerned with a variety of issues associated with the use of subsidized prices to prevent industrial customers from leaving the gas distribution network. In particular, there is a need to disentangle those arguments that make sense in the context of the current environment, one that economists term disequilibrium, from those arguments that make sense when the obscuring mist of the current situation is removed and longer-term public interests are considered. Regulated price discrimination should account for the short-term disequilibrium conditions as well as the long-term equilibrium that is inevitable.

Price Discrimination

It is a major requirement of federal and state laws that utilities furnish their services without "undue" discrimination among customers. A related requirement is that rates be "just and reasonable." For the most part, legislatures have left the task of interpreting the terms "undue" and "unreasonable" to the commissions. In light of the long experience of rate regulation in this country, it would seem reasonable to expect clear criteria that would distinguish due from undue discrimination.

Not only is the distinction between due and undue discrimination unclear, the very term price discrimination is frought with problems of definition. A traditional statement is that price discrimination occurs when the same commodity is sold at different prices to different but similar consumers. Unfortunately, this concept is not comprehensive and possibly can be confusing. The definition does not cover a variety of price discrimination phenomena and can misclassify some situations that are not in the category of price discrimination, in actuality.

In part, the above definition is faulty because of the absence of a clear and unambiguous definition of the term commodity. Gas sold to residential customers and industrial customers is not the same commodity inasmuch as the location, time, and conditions of consumption are different for these two customer classes. Differences in rates that correspond to differences in the cost of supplying the commodity are not discriminatory.

In a narrow sense, economists judge rates to be discriminatory when rates deviate from marginal cost. The absence of discrimination is a natural by-product of setting prices at marginal cost--a situation that would prevail automatically under perfect competition. Under competition, a product would not be sold at a discount. It is true that firms producing under competitive conditions do assign common costs to different products. The extent of this assignment, however, is limited by competition. To the extent that firms do have some monopoly power, they may separate markets, using advertising, for example, and price discriminate. In their famous paper on "Optimal Departures from Marginal Cost Pricing," Baumol and Bradford claimed that the theoretical competitive model is removed from reality sufficiently that price discrimination is a common practice in real life situations.[4]

In the case of public utilities, large fixed costs make the required deviation from marginal cost substantial. Some economists have argued for proportional deviations from marginal cost by claiming that such deviations would represent due discrimination. Proportional adjustment may not be possible in today's gas market. The same percentage mark-up for multi-fuel industrial users and residential customers may cause the industrials to leave the system. Thus, proportional adjustment may lead to uneconomical consumption choices.

To minimize such welfare losses, economists recommend the use of prices that deviate from marginal cost in inverse proportion to the customers' elasticity of demand. These so-called Ramsey prices represent rate discrimination on the basis of value of service, although cost differences are fundamental as well.

To clarify the distinction between due and undue price discrimination it is necessary to consider several perspectives in light of situations like those experienced recently in the Delmarva case described previously. Continuation of a single price to be charged to all customers threatens the loss of some load. The first view suggests that any price discount larger than needed to prevent the loss of load is excessive and may be considered undue. As a benchmark regulators may wish to consider the price of alternative fuels in the case of customers with multi-fuel boilers. Alternatively, regulators may wish to define stand-alone costs as the appropriate benchmark for this first view.

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[4] W. J. Baumol and D. F. Bradford, "Optimal Departures from Marginal Cost Pricing," American Economic Review, 1970, 60, 265-83. For an extensive review of the economic literature on price discrimination, see Louis Philips, The Economics of Price Discrimination (Cambridge: Cambridge University Press, 1981).

Simply stated, stand-alone cost is the cost of setting up a utility with one customer class only. With either of these benchmarks in mind, according to the first perspective, undue price discrimination can be defined as the excess subsidy to industrial customers beyond that needed to keep them connected. A characteristic of this view is that there is only a single limit price. Below this price, discrimination is deemed undue and above it load loss occurs. That is, there is only one price that simultaneously prevents loss of load and would not be considered unduly discriminatory.

Any subsidy granted to industrial users beyond that of the first perspective almost certainly results in increased prices that captive residential and commercial customers need to pay. A second view for knowing whether an industrial discount is unduly discriminatory is the stand-alone cost of the other customers, who could break away if such discrimination became extreme. An alternate benchmark consistent with this second view would be the point at which residential customers begin to use electricity instead of gas.

Yet a third perspective can be based on the marginal cost of serving the industrial customers. At prices below marginal cost it is obvious that the other captive customers not only pay for the entire fixed cost, but also pay for some of the variable cost of serving the industrial load. Clearly the industrial marginal cost may be considered a lower limit for the price that they are charged. It should be noted that an industrial price below marginal cost may not be unduly discriminatory to residential customers from the previously described second perspective, if residential users do not leave the system. The second viewpoint, then, might allow very extreme forms of price discrimination.

Incidentally, the marginal cost of serving industrials is not known precisely because of the variety of vintages of long-term contracts. It is possible that the very low price being charged to industrials is above true economic marginal cost. In such a case, it may be feasible to lower the price to industrials without raising the rates that are charged to the captive customers.

In the first two perspectives a basic criterion for due or undue price discrimination, it is argued here, is stand-alone costs. Such a standard requires that we know something of the structure of the industry's costs. Furthermore, in the case of franchised monopolies, such as gas distribution, the need for price discrimination raises the possibility that the monopoly franchise may be not justified. The possibility exists that the structure of the gas industry is not efficient. At the distribution end, it is possible to imagine conditions that would constitute a reason for not extending franchised monopoly to the industrial load. Such might be the case when industrial customers can tap gas directly from several alternate pipelines that are in competition.

The cost structure of the distribution system may display economies of scope, defined as

$$C^m (q_1, q_2) < C^1 (q_1, 0) + C^2 (0, q_2),$$

where:

$C^1 (q_1, 0)$ = cost of producing product 1 alone,

$C^2 (0, q_2)$ = cost of producing product 2 alone,

$C^m (q_1, q_2)$ = cost of producing products 1 and 2 jointly.

To illustrate some of the above concepts consider a utility endowed with economies of scope so that the cost of serving two customer classes jointly is 85 while the cost of serving the industrial class alone is 20 and the residential class alone is 70. Thus, the sum of serving the two classes independently, 90, exceeds the joint cost of 85.

The joint cost function is said to be subadditive and hence economics of scope are present.

Furthermore, suppose that the associated common costs to the two customer classes and the assignable variable costs are 40, 15, and 30 respectively. Suppose that the incremental cost of serving the industrial market is above the assignable variable cost of that customer class, but below its stand-alone cost. That is, the incremental cost of the industrial customer class is between 15 and 20. A zero profit constraint would imply that the price for the residential customers must be no more than 70. The pricing limits for industrials, combined with the zero profit restriction mean that the price to the residential class cannot be lower than 65.

In this example there exists a possibility that residential customers pay the entire common costs and the industrial customers do not contribute to them. In such a case there is no excess burden since the monopoly price does not exceed the stand-alone cost. Indeed, a more extreme example is imaginable. It is possible to encounter a situation such that residential customers would be forced to pay the entire fixed cost and a portion of the variable costs of industrial customers without being price discriminated against in terms of the stand-alone cost definition. Yet, in terms of social welfare pricing, as might be indicated by Ramsey prices, such a situation would not be desirable.

To sum up the above, price discrimination is an inevitable part of public utility pricing. This is because marginal cost based rates do not cover the large fixed costs that accompany utility services. Price discrimination exists whenever price deviations exceed discrepancies in the services' marginal costs. The discrimination becomes undue when prices exceed some preset and agreed on limit. In some instances, price subsidies that cover all the fixed costs and some of the variable costs of serving industrial gas customers may not result in undue price discrimination of the captive residential and commercial customers. In such cases it may be necessary to reconsider the definition of the border line between due and undue price discrimination. It seems reasonable to claim that subsidies that cover more than just the fixed costs result in undue discrimination.

Practical Considerations

In light of the theoretical considerations outlined in the previous section, it would seem that a prerequisite for determining whether particular pricing policies constitute due or undue discrimination is the availability of extensive knowledge concerning the entire cost structure of the gas utility, including the extent of existing economies of scope. Furthermore, information concerning non-cost complementaries among gas users, such as mutually beneficial effects on the aggregate demand, may be of use. In this section an effort is made to set out the informational requirements for determining the nature of price discrimination and its desirability. In addition, a case will be presented for changing the focus of the discussion from the limits to industrial users' subsidization to the proper structure of charges in the context of two-part tariffs.

Under What Circumstances Is It Important To Calculate Stand-Alone Costs?

Simply stated, the significance of stand-alone costs as a standard for determining the nature of price discrimination is predicated on the existence, or absence, of other narrower limits to the subsidies that industrial users can be given. Some of these were hinted at in the previous section. To see the relationships among these limits clearly, consider figure 1.

Figure 1, borrowed from a recent NRRI report,[5] presents two loci of various prices that can be charged to two groups of customers without

[5] J. Stephen Henderson and Jean-Michel Guldmann, Natural Gas Rate Design and Transportation Policy Under Deregulation and Market Uncertainty (Columbus, OH: NRRI, 1985), p. 44.

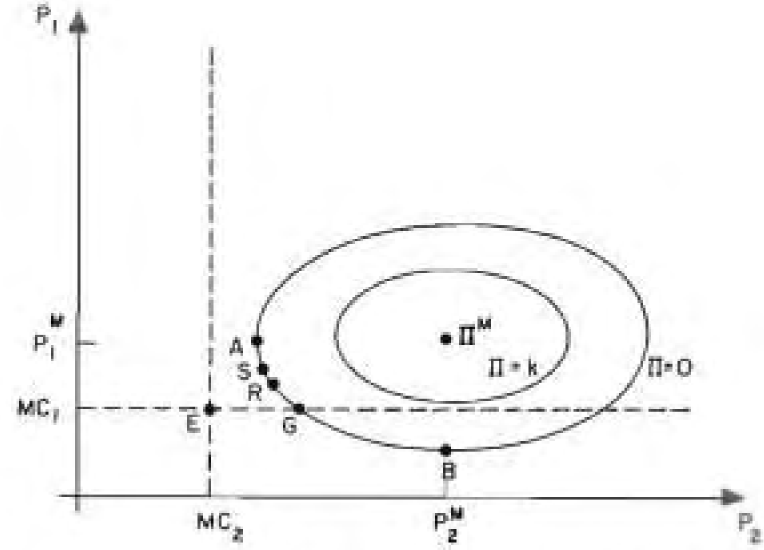


Fig. 1 Constant-profit schedules and limit prices

affecting the profits of the gas utility. Three profit levels are indicated. The outer curve represents zero profits. For simplicity's sake this level will be assumed to represent the regulatory standard. The inner curve represents some positive profit level k. In addition, in the center of the figure there is a single point showing the prices that result in the maximum monopoly profits for these two markets together.

Point E, in the south-west part of the figure, represents the set of the marginal costs of serving the two markets. Its location below the zero profit locus is indicative of a typical utility situation with large fixed costs. The ever present need to price discriminate is demonstrated by the need to set prices on the outer curve which does not include point E.

From among the points on this curve those outside the segment AB are clearly inferior. Points A and B represent the high prices that an unregulated monopolist would charge. To see the nature of these two points more clearly consider figure 2. It illustrates the determination and significance of point A.

P^* in figure 2 corresponds to P_1 in figure 1. In particular, it is the point where marginal revenue equals marginal cost, at point K. This point is the maximum contribution to fixed cost that can be extracted from a class of customers with the willingness to pay given by demand curve dd. To see this, consider the set of curves indicated by the numbers 1, 2, 3, and 4. These are "regulated-supply" curves that include a constant marginal cost and an assignment of fixed cost spread over the gas bought. These loci can be expressed as:

$$P = MC + f_i \; F \; / \; Q \; ,$$

where

f_i = the fraction of fixed cost assigned,

F = total fixed cost, and

Q = quantity consumed.

For smaller fractions of fixed cost assigned, the price locus is lower. The highest fraction possible, f^*_i say, results in locus 3. Any attempt to collect a higher fraction, say that associated with locus 4, is futile and simply cannot be supported by the market.

Between points A and G, in figure 1, a possible limit price may be defined by the cost of directly connecting an industrial customer to the pipeline. The existence of such a point and its exact location depend on the capital costs of a new independent connection compared with the maximal assignment of the existing fixed cost, f^*_i, of the local distribution utility. To a large extent the outcome of such a comparison depends on the geographic location of the industrial customers in relation to the city gate. It is possible to imagine that such a point, for example S in figure 1, would represent a lower limit for the industrial price below which residential users are unduly discriminated against.

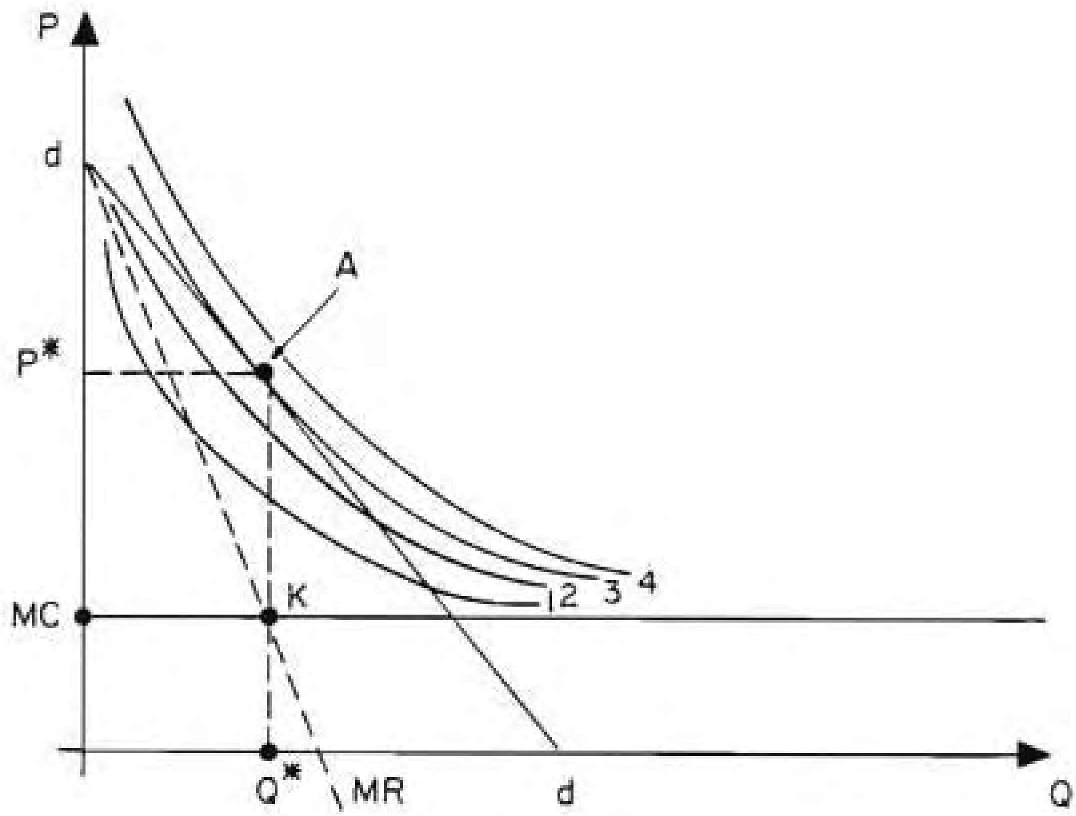


Fig. 2 Unrestricted monopoly prices

The choice of a combination of prices within the segment AB in figure 1 is made difficult because price reductions to one group are made at the expense of the other group. Point R shows the Ramsey prices that maximize the social welfare. At point G the entire fixed cost, segment EG, is borne by residential customers while industrial customers pay for their own marginal cost only.

Point G represents a different distinction that might be drawn between due and undue price discrimination. Charging less than marginal cost to industrial users cannot be justified typically. This conclusion might be relaxed if there were some other benefit to the residential users from retaining industrial load. Such may be the case if the presence of industrial customers, made possible by short-term subsidies below point G, would lead to long-term reductions in marginal cost, so that point E moves to the south-west. These types of economies will lead to reduced prices to both groups. It is important to note that a distinction has been drawn here between short-term pricing policies and longer-term effects.

To conclude, the danger points include the marginal cost of industrial users (point G), the stand-alone cost for industrial users connecting directly into the pipeline (point S), and the unregulated monopoly price (point B). Without an appropriate empirical study it is not possible to determine the exact location of each of these points. Depending on which perspective is adopted it may not be necessary to estimate the entire cost structure of the utility in order to identify undue price discrimination. The danger signal of undue discrimination will be sounded with the first industrial customers switching out. At lower prices a danger should be signaled as soon as industrial customers stop paying their own variable costs. The motivation for such subsidies should be clearly identified.

How Does The Disequilibrium In The Gas Industry Affect The Limits To Price Discrimination?

The current conditions of the gas industry and the present regulatory practices cause changes in the various limits to price discrimination that were described above. In the absence of regulation induced price inflexibility, it would be expected that reductions in the price of substitute fuels would be met by reductions in the price of gas, without the need for placing an excessive burden on residential customers. Undue price discrimination would be of only academic interest.

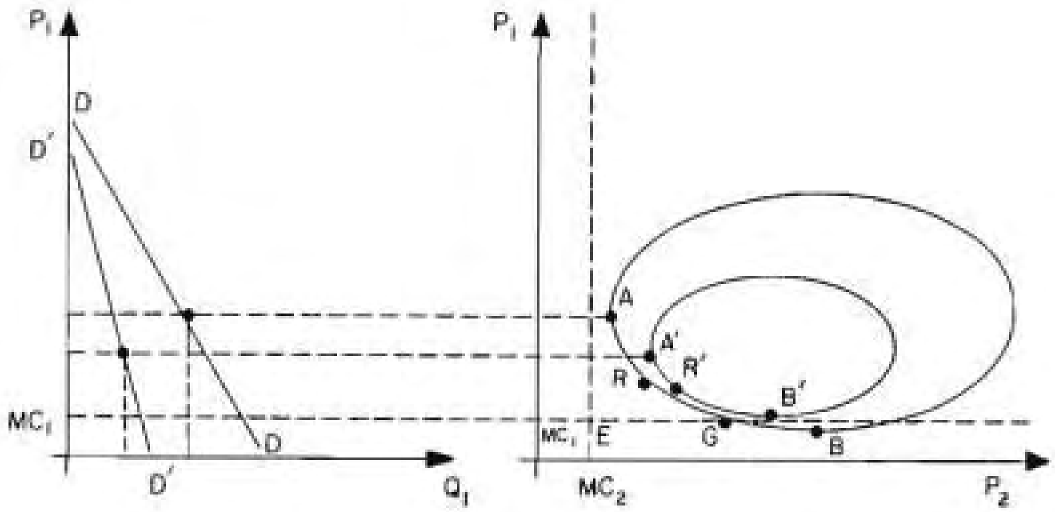
The price inflexibility that is characteristic of today's situation causes changes in figure 1 that are illustrated in figure 3. Panel A of figure 3 illustrates the reduced willingness to pay for gas by industrial customers who have the option of consuming reduced-price fuel substitutes. Panel B illustrates the effect that this change in the demand curve has on the zero-profit locus of figure 1, here duplicated for convenience.

The reduced willingness to pay for gas by industrial users means that the profit maximizing price that an unregulated monopoly would charge these customers is lowered, as indicated in panel A. In terms of the zero profit locus of prices, the effect is to increase the price that will be required from the residential customers. In short, panel B illustrates the new locus that is associated with disequilibrium in the gas market.

Points A' and B' represent a reduced range of possible combinations of prices in the two markets. While the Ramsey price continues to be located between these two points, it is not clear whether the other limit price, i.e., the stand-alone cost, is lower or higher than the monopoly price in the industrial market, point A'. Irrespective of their precise locations, it is obvious that the range of choices is reduced.

Should The PUCs Attempt To Prevent Industrial Gas Customers From Leaving Local Distribution Systems?

Up to now the term "industrial customers" was sufficient to describe a variety of customers who might consider leaving the local distribution system for either a direct link to the pipelines, or in order to consume an alternate fuel. At this point it is important to distinguish industrial customers served under an interruptible contract from those who are firm customers. The former's willingness to be interrupted stems from their ability to switch to other fuels at a minimal cost.



Panel A

Changes In Demand For
Industrial Gas

Panel B

Changes In The Zero-Profit
Locus

Fig. 3 Demand Curves, constant-profit schedules, and limit prices under conditions of disequilibrium

In addition to any contribution to fixed costs that these customers may make, the possibility of interrupting them can contribute to improved load management. The effects on spot prices of wrong guesses concerning future demand and supply can be eliminated, or at least alleviated, by the curtailment of large users capable of consuming other fuels. Furthermore, the industrial customers may contribute to an inflated estimate of demand, leading to expanded optimal capacity, which may be placed at the disposal of non-industrial customers during periods of peak demand.[6]

A related issue, which is suggested by the above, concerns the possibility that industrial customers may wish to leave the utility during periods of low oil prices or when cheap spot market gas is available and may wish to return to consume utility supplied gas later. This type of sporadic consumption may create two difficulties for the gas utility.

The first difficulty is related to optimal capacity planning. If granted, the permission to reconnect at the discretion of the industrial customers and in response to unknowable changes in relative energy prices will increase the utility's demand uncertainty. If nothing else, it may cause an increase in the utility's cost of capital. In addition, however, if the possibility of sporadic consumption is not accompanied by an appropriate stand-by or "access" charge, the utility may have insufficient capacity. Properly designed stand-by charges, on the other hand, can provide correct signals to both the sporadic industrial customers and to the utility so that the decision concerning which fuel to consume would be made on economic grounds and contribute to the efficient allocation of resources and to the capacity planning process so that there does not arise a situation of excess demand due to insufficient distribution capacity.

An entirely different issue is associated with the current situation of disequilibrium in the gas market. At least in part, the propensity of industrial customers to seek alternate fuels, including self-contracted for gas, is the result of regulation-induced discrepancies in gas prices. In effect, the need to price discriminate, in a fashion that raises the issue of undue discrimination, is the result of a regulation-induced disequilibrium, which is not likely to persist

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[6] "The Fixed-Variable Paradigm, Guidance for Future Gas Transactions," ARTA Energy Insights, Number 6, April 1984, p. 4.

for many years. Although this is a short term problem, state regulators may wish to consider the price discrimination issue in the context of this disequilibrium.

How Should The Industrial Stand-by Charge Be Designed?

An economically proper way to price a gas utility's services has been in effect at the city gate following the Natural Gas Act of 1938 and until the early 1950s. The simple two-part tariff included a demand charge that covered the utility's fixed costs and a commodity charge that was intended as a mechanism to cover all the variable costs. No fixed costs were included in the commodity charge. The demand charge was not paid by some customers. Later, some fixed costs were recovered in the commodity charge. This creates imprecise signals concerning true costs and may lead to improper decisions concerning optimal expansion of capacity.

The elimination of fixed costs from the commodity charge would reduce somewhat the cost of gas to interruptible customers and make gas more competitive with other fuels. But, should interruptible customers, and sporadic industrial customers, contribute to the utility's fixed costs? Certainly, if the industrial users wish to reduce the chance of being interrupted during peak demand periods. But beyond this consideration there is the possibility that the prolonged, if not permanent, absence of industrial customers may lead to scaled-down utilities. In the long-run such a possibility may affect not only the industrial users, who may be curtailed, but the residential users as well. To prevent this from happening some chance-weighted stand-by charge paid by sporadic industrial customers is appropriate.

In essence, long term considerations cannot preclude periods during which relative energy prices will favor gas and periods during which gas will be relatively expensive. In order to promote efficient consumption patterns of energy, it is important that gas prices reflect their true commodity costs. The price of the right to consume gas should reflect the cost of the added capacity needed to assure that service will be available on demand. To the extent that this service is required sporadically only, the charge should reflect the added probabilistically expected cost. Such a price will not only promote efficient consumption choices, it will also provide correct information to utility planners concerning the required added capacity.

Concluding Remarks

Concern with excessive price discrimination is the result of two separate phenomena, both of which raise the possibility that some of a gas utility's load will be lost. The main impetus for lowering gas prices for some customers is the periodic occurrence of low oil prices. Even in the case of energy markets that are functioning smoothly, prices of various energy forms will occasionally differ. Fuel switching is efficient in such circumstances and would tend to eliminate price differences between energy types. Federal regulation of gas prices has contributed to their inflexibility which may mean that more fuel switching will occur than would be the case with more efficient markets. A second reason for considering excessive gas price discrimination is the regulation-induced spread in the prices of available gas.

This paper has identified a number of limits to price discrimination that might appear naturally in the marketplace. Undue price discrimination was defined in terms of the burden that when imposed -- would drive customers to alternate fuels, or to set up a separate utility. But, the main issue is of a different sort.

Given that alternate fuels, including self-contracted for gas, are available, there is a need to reconsider the franchise arrangements that have been agreed upon in the past. Perhaps the industrial, sporadic customers should not be considered part of the utility in the sense of the utility's obligation to serve. In such a case, it makes sense that their consumption of gas would take place under a special pricing arrangement. Economic efficiency considerations suggest that such customers should consume those fuels with the lowest price. To the extent that the true economic price of gas is lower, gas should be consumed. To make sure that gas is available to these sporadic customers and that sufficient serving capacity is available, there is a need to devise an appropriate stand-by charge, one that would reflect the probability of serving them.

GAS SUPPLY AND TRANSMISSION CAPACITY CONTRACTING

BY LOCAL DISTRIBUTION COMPANIES

by J. Rodney Lemon

Professor of Economics
Monmouth College
Monmouth, IL 61462

Changes within the Industry and Contracting Practices

The natural gas industry is in the midst of fundamental change. At the wellhead, the price of new natural gas has been deregulated by the Natural Gas Policy Act (NGPA), and the price ceilings on old gas have been deliberately set at ineffective levels by the FERC under Order 451. Wellhead prices, thus, are set by market forces, not by the regulator or legislator.[1] In the interstate market, natural gas transportation, flexible rates, and expedited certification of new services and facilities under FERC Order 436 have given pipelines and consumers more choices.[2]

Order 436 also gave the local distribution companies (LDCs) contract demand conversion and reduction rights, and allowed the customer to specify the duration of the transportation contract. Local distribution companies gained new freedoms and responsibilities: the price and reliability of both gas supply and transportation depend upon an LDC's purchasing strategy. The gas utility manager now has choices similar to those of the manager of a multi-plant electrical utility.

All of these changes warrant a fundamental reevaluation of state commission regulatory policy regarding LDC contracts for gas supply and transmission capacity. This evaluation cannot be made without some

[1] Not all market forces are competitive; consumer protection rests partially on the distributor's search for low prices.

[2] For the purposes of analysis, it seems appropriate to assume that a large number of pipelines will elect 436 transportation.

uncertainty and controversy. Some observers, for instance, argue that once the pipelines realign their "problem contracts," former contracting practices will reemerge.[3] Others argue that traditional long-term contracting will continue for LDC core customers.[4] This controversy hinges upon different assumptions about current industry practices. The previously cited institutional changes have occurred simultaneously with a novel market situation--the pipeline's average cost of gas has been higher than its marginal cost. This situation produced changes in the traditional structure of the industry including LDC spot market purchases; industrial bypass of LDCs and LDC bypass of pipelines; and unbundling of transportation and merchandising services.[5]

The study attempts to shed light on the motives for and permanence of current contracting practices for the gas commodity and the capacity to transmit it. The following section identifies the traditional arguments used to justify long-term gas supply contracts and how this foundation would have changed even had there been no market disorder.[6] The remainder of the paper deals with contracting practices and how a state commission might encourage optimal LDC contracting.

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[3] Southern California Gas, for example, has estimated that their spot purchases will diminish. Robert Means of Swanson Energy projects that many LDCs will return to their traditional relationship with their pipeline suppliers.

[4] Arlon Tussing has indicated that it is inappropriate for an LDC to use long-term contracting for its interruptible or fuel switchable customers. The California Public Utility Commission adopted this distinction in their Transportation Proceeding (84-04-079) issued March 12, 1986.

[5] These changes have been substantial. Spot and short-term contracting may constitute 40 percent of total volume in 1986. See: Ben Schlesinger, speech presented at Energy Daily's Conference, May 21, 1986.

[6] Most of the changes that have occurred (for example, the rise of the independent merchant or reliance upon the spot market) would not have been so pronounced without this market situation. That is, the pipeline would have had a tied product (cheaper average cost of gas because of its possession of old gas) that would have lessened these changes.

Evolution in Long-Term Contracting Practices

The natural gas industry has historically been governed by long-term contracts linking producers with pipelines and pipelines with local distribution utilities.[7] These long-term contracting practices have been cited as providing the vertical integration necessary to 1) prevent opportunistic behavior, 2) lower risk, 3) provide efficiency, 4) guarantee supply reliability, and 5) reduce consumer cost of service.[8]

Major problems with these long-term contractual relationships have become apparent.[9] A principal reason for long-term wellhead contracts has been related to pipeline financing. Because pipelines are capital intensive, and were once considered high-risk ventures, financial institutions required assurances that they would recoup their investments.[10] The most obvious assurance was proof of an adequate supply of gas to permit a pipeline life long enough to recoup the

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[7] Pipelines have a contractual obligation to both producers and their customers. Distributors, on the other hand, have a service obligation only to their burner-tip customers. The lack of a written contract between customer and distributor is the missing link in long-term contracts that connect the wellhead to the burner-tip.

[8] M. Elizabeth Sanders, The Regulation of Natural Gas (Philadelphia, PA: Temple University Press, 1981), p. 116.

[9] Rodney Smith has argued that the FERC has been a principal force in mandating this problem with Orders 380, 436, and the April 1985 Statement of Policy Take-or-Pay. (Address presented at the meeting of the International Association of Energy Economists, Philadelphia, PA, November 18, 1985.) Raymond O'Connor, former FERC Chairman, has countered that the problems were already in existence and would have continued to worsen even without FERC action. Further, the FERC should have interfered. (Address presented at the meeting of the Federal Energy Bar Association, Washington, DC, May 22, 1986.)

[10] The early years of the natural gas industry were characterized by boom-bust cycles. Natural gas would be found in the Middle Atlantic and North Central regions quite cheaply, gas utilities serving towns would develop, and then the gas wells would become depleted. The large gas fields in the Southwest changed this pattern.

investors' money. Long-term wellhead contracts became institutionalized with the blessing of the Federal Power Commission.[11]

Long-term contracts should not be considered a technological necessity. Historically gas has been produced from the same wells as oil and essentially uses the same technology. Oil is sold virtually on a spot basis. A 30-day transaction period is normal, with contracts continually turning over. Oil production has never required long-term contracts to protect or recoup drilling investment or to provide incentives to drill. However, the vertical integration in the oil industry is provided by the major producers. Yet a large number of independent firms exist at each stage of this industry. Gas was first produced and sold as a byproduct of oil. Indeed, the many similarities between the two products suggest no reason why long-term contracts would be required to recoup or protect investments in one production process and not the other. The difference between gas and oil contract terms may reflect instead, the fact that oil pipelines are regulated as common carriers while gas pipelines are not.

Qualities of Long-Term Contracts

An extensive literature suggests various reasons why long-term contracts minimize costs.[12] These factors are 1) lower transaction costs; 2) lower financial risk from more certain demand and cash flow,

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[11] The Federal Power Commission (FPC) evaluated long-term supply and demand before certifying a new capital investment. Long-term contracts clearly were helpful in providing proof. Wall Street investment houses conducted their own evaluations and did not necessarily rely upon FPC certification.

[12] See: Benjamin Klein, Robert Crawford, and Armen Alchain, "Vertical Integration, Appropriate Rents, and the Competitive Contracting Process," Journal of Law and Economics (October 1978): 297-326; Michael Canes and Donald Norman, "Long-Term Contracts and Market Forces in the Natural Gas Market," Journal of Energy and Development 10, 1: 73-96; and Oliver Williamson, "Transaction-Costs Economies: The Governance of Contractual Relations," Journal of Law and Economics (October 1979).

which may lower the cost of capital; and 3) less possibility of opportunistic behavior because of idiosyncratic investments.

Transaction costs refer to costs of negotiating, monitoring, and enforcing contracts, including the costs associated with contract failure. An efficient institutional arrangement would seek to minimize these costs. The efficient choice is influenced by the nature of both the transaction and the parties to it. In practice, complete contracts cannot be written because of the expense of enumerating all possible future events. In addition, human agents may pursue their self interests in possibly guileful ways.

The characteristics of the transaction refer to the frequency with which a transaction occurs, the uncertainty or complexity surrounding the transaction, and the extent to which transaction-specific (idiosyncratic) investments are involved. The latter has particular significance in the natural gas industry since the pipeline and gathering lines may be essential facilities. While the producer may have a choice of areas in which to explore and develop gas wells, once these wells are completed, the producer has no say in how the gas reaches other buyers. Likewise, the pipeline or gathering facility may be dependent upon this producer. Once the investments have been made, their value in other circumstances is greatly diminished.

This means that both the buyer and seller are locked into the transaction after the investments are made. In such a situation, each party is in a position to negotiate incremental gains whenever the contract is reopened. Henderson and Guldmann note that "an anticipated need for frequent ex-post adaptations in the contract would require a governance structure that recognizes such opportunism, possibly vertical integration."[13] This dimension has been used to justify long-term

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[13] J. Stephen Henderson and Jean-Michel Guldmann, Natural Gas Rate Design and Transportation Policy under Deregulation and Market Uncertainty (Columbus, OH: The National Regulatory Research Institute, 1986), p. 65.

natural gas wellhead contracts.[14] If pricing rules are specified in long-term contracts with take-or-pay provisions before investment is undertaken, potential problems with opportunism can be controlled.

Frequent transactions that do not involve idiosyncratic costs tend to promote good performance by each party. Poor performance can lead to termination of a valuable ongoing relationship. Frequent transactions may be self-enforcing and have low transaction costs.

Complex and uncertain transactions characteristically will have high transaction costs. Internal organization may be required to economize on transactions that are either costly to negotiate or costly to enforce.

This discussion suggests that spot market contracting will be efficient when transactions are frequent, uncertainty is manageable, and the potential for opportunism is minimal. Long-term contracts are required for infrequent transactions, and those that allow ample scope for opportunistic behavior. Vertical integration is expected when uncertainty is unmanageable and capital is immobile after the fact.[15]

Long-term wellhead contracts for natural gas have been a market-driven solution, largely because of the potential for opportunistic behavior. Given the regulatory setting, long-term contracting enabled investment and exchange to proceed. The rules enforcing long-term contracts are critical, for these rules facilitate efficient market exchange by providing protection to the economic function of contracts.[16]

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[14] Rodney Smith, Comments of Stratecom, Inc., FERC Docket No. RM85-1-000 (Part D). Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, November 18, 1985, p. 34.

[15] Long-term contracts promised supply and market security and defused an impulse to vertical integration. See: Arlon Tussing and Connie Barlow, The Natural Gas Industry (Cambridge, MA: Ballinger, 1984), p. 211.

[16] The efficiency depends upon optimal regulatory rules. If the regulatory structure of the industry is itself inefficient, then the market-driven efficiency resulting in long-term contracted terms is also likely to be inefficient from society's perspective.

Regulatory Structure and Attributes of Long-Term Contracts

The preceding conclusions depend upon the regulatory setting. Wellhead price controls under the Natural Gas Act (administered by the Federal Power Commission) and the infant nature of this market meant that all gas supply was marketable. There was little or no demand uncertainty for conventional natural gas. Further, the ability to roll-in higher cost with old gas under the NGPA also decreased demand uncertainty until 1982. However, effective price controls meant gas shortages and the likelihood of allocation schemes based upon factors other than price. Long-term supply contracts removed some of this regulatory-induced uncertainty.

Second, the NGA was interpreted as affording interstate pipelines private carrier status.[17] Private carriers have the right to deny access to their transmission systems. Since a large area can be served by a single pipeline, the markets are geographically diffused and each tries to define a sufficient volume of wellhead production and burner-tip use to take advantage of potential economies. As the natural gas market has expanded and matured, a greater number of interstate pipelines have entered most major producing regions.[18] The extent of monopsony power has diminished, yet many producers are still connected with one gathering system or pipeline, and idiosyncratic investment remains a common characteristic.[19] Regulation affording pipelines the right to deny access to alternative purchasers and limit the number of purchasers with whom the producers can contract is inappropriate and is

[17] While the NGA explicitly conferred private carriage status, the NGA and the Supreme Court also charged the regulatory agency with setting just and reasonable wellhead prices. The NGPA modified this regulation with directives toward competitive markets. The latter are not possible without common carriage.
[18] Paul MacAvoy, Price Formulation in Natural Gas Fields (New Haven: Yale University Press, 1962).
[19] It remains to be seen whether relative minor investments might not alter this characteristic.

subject to change.[20] These changes reduce the potential for opportunistic behavior.

The preceding suggests that long-term contracts may be prevalent due to the former regulatory setting, not necessarily because those contracts are the most efficient. Carrying this discussion further, let us analyze whether spot market contracts can resolve uncertainty of supply, end fear of opportunistic behavior, and generate needed investments. This analysis assumes the new regulatory setting of deregulated wellhead price ceilings and open access transportation.

Supply Security

In the past, supply security was measured by the ratio of each pipeline's dedicated reserves to annual sales (production). This measurement was partially correct when wellhead prices were held artificially low and allocation rulings affected which customers of a pipeline gained access to reserves dedicated to interstate commerce. Wellhead price ceilings have now been eliminated, and reserve dedication can be quickly reassigned. Today, supply security is only available to those willing to pay the market price, with reserves essentially dedicated to a North American market.

The reliance upon market price for security is valid even though 1) there is a considerable lag from the time the producer decides to increase exploratory or developmental activities to when these new supplies reach the market in sufficient quantities; and 2) transportation has limited routings and capacity. However, higher prices will quickly generate additional supply for those willing to pay. This supply will come from higher rates of production from existing

[20] Order 436 provided a means for self-implementing transportation for all customer classes. Order 451 provided for mandatory transportation for old gas released by the pipeline. The NGA prohibits undue discrimination or preference in the provision of transportation services.

wells and from some users switching to alternative fuels, thus freeing their gas supplies for those willing to pay higher prices. Both of these actions will also limit the extent to which prices will rise.

A specific transportation bottleneck cannot be used to justify long-term contracts to ensure supply, due to the interpipeline exchanges and the transportation that brings national market opportunities to most pipeline systems. Further, the LDC may move to spot purchase because the producer prefers this contract form. Reliance upon market price and spot purchases may not involve any great redirection of existing gas flows.

Long-term contracting is essential only when the market is failing or government intervention prevents market forces from operating. First, while government intervention is possible, it would probably not be opposed to the LDC interests. The LDCs need not contract for their long-term needs in favorable regulatory periods expecting that the government will prevent them from getting supplies when they need them. Second, if the market price were subject to exploitation, market failure would be evident. Yet, there is little capital barrier to entry into the merchant function and anyone can acquire enough knowledge to become a broker. Little evidence exists to suggest that either gas supply or its merchandising is incompatible with open access. Supply security need not entail long-term contracts. If long-term contracting is dominant, it is not for security reasons.

Opportunistic Behavior

Order 436 was an attempt to unbundle gas supply from transportation and to increase competition in the natural gas industry for gas supply and merchandising.[21] The emergence of a large spot market, numerous

[21] The Optional Expedited Certification provision of Order 436 may also greatly facilitate interpipeline competition. See Rod Lemon, "The
(Footnote continues on next page)

independent and affiliated merchants, negligible barriers to the merchant role, and open access to transportation have all served to reduce the pipelines' opportunistic behavior. A producer could contract entirely on a 30-day basis, as could a consumer, and have a continous supply at a competitive wellhead price if transportation capacity were available.

Is open access to transportation sufficient to end all opportunistic pipeline behavior? Independent marketers are concerned over how pipelines have allocated capacity; developed postage-stamp rates; set forth imbalance penalties; and denied access to storage, backhaul, and exchanges. However, with the development of a national gas reservations model and with renewed competitive regulation by the FERC, the chances for opportunistic behavior will probably be diminished further.[22]

With less opportunistic behavior by the pipeline, have the producers and the pipelines' customers gained an opportunity to exploit the pipelines themselves? Probably not. First, the pipeline may be an essential facility for the producer or customer, while neither of these groups could be called "essential" to the pipeline. Second, the pipeline's exposure to opportunistic behavior is limited by competitive alternatives. The pipeline will always be able to extract a competitive rate, but this may be below its regulatory just and reasonable rate. This reasoning follows from the fact that producers' power is limited by rates offered by others. This holds true also for the LDC. Selective

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(Footnote continued from previous page)

Regulation of Natural Gas Pipelines through Mandatory Carriage and Open Entry," paper presented to the Western Economic Association, Anaheim, CA (July 1985).

[22] Dun and Bradstreet and Jensen Associates have developed The Official Pipeline Guide, a personal computer-based pipeline mapping system. When linked with rate data on all pipelines and historical capacity utilization, the system allows the user to determine the cheapest routes and helps the user negotiate final arrangements. It is interesting to note that Dun and Bradstreet has compiled the only unbiased airline reservation model.

discounting, an aspect of Order 436, will allow the pipeline to respond to these new competitive forces with maximum flexibility.

Financial Cost of External Funds

Reliance upon the spot markets does not replace known demand with uncertain demand; the spot market can always absorb the available supply.[23] Further, the pipeline's exposure to risk will be less once it ceases to buy and sell.[24] The cost to the pipeline increases only if capacity contracting also shifts to spot transactions. In this case, regulatory guarantees mean less; however, the competitive producer, as well as the competitive pipeline, will continue to have good access to external funds as their competitive position lowers their risk.[25]

Conclusion

This section has found that the prevalence of long-term contracts is due as much to the regulatory setting as it is to the inherent efficiency of long-term contracting.[26] This means that long-term contracting is not necessarily the most efficient; the industry could,

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[23] The additional demand may come from other producers deciding that the market price was below their reservation price and yielding their customers to other producers. This parallels action on the opposite--side when prices rise.

[24] Paul Carpenter and Arthur Wright, "Risk Allocation and Institutional Arrangements in Natural Gas," paper presented to the American Economic Association, San Francisco, CA, December 30, 1983.

[25] Of course investors evaluate the underlying economics of a project before investing. The underlying economics are simpler if the pipeline has regulatory approval and has entered into various long-term contracts. If the contracts are not economic, they won't stand the test of time. The Trunkline LNG project demonstrates this.

[26] It should be emphatically noted that the structure of the industry cannot be returned to a pre-1984 situation. Wellhead price controls were disastrous. Without wellhead price controls, pipelines would extend market power over transmission to include unregulated gas supply. Regulatory change is a logical outgrowth rather than a fad that will pass.

at some cost (possibly lower, possibly higher), operate entirely on short-term contracting.

Determining the Best Mix of Supply Contracts

Introduction

The current institutional setting within which contracts are formed includes: 1) largely unregulated wellhead prices,[27] 2) a developing futures and spot market,[28] 3) open access to transportation,[29] and 4) options about achieving supply reliability. The pipeline, the local distribution company, and other merchants have new choices about how they contract for gas supply. Further, the LDC or other merchants also have a choice in purchasing transmission capacity, which may now be for short durations or via new linkages.

In this new institutional setting, the relative advantages of one type of contracting over another may have changed. This section identifies alternative types of contracts and assesses the advantages of these contracts from both the buyers' and sellers' viewpoints. Contract attributes are based upon the various risks to which this contract exposes the parties. The analysis also identifies how various external factors affect these alternatives. Finally, the section suggests what new contract forms will emerge and which merchant is likely to be best able to package gas supplies.

[27] The NGPA deregulated most categories of new gas as of January 1, 1985 and the FERC significantly raised the price ceiling on most categories of old gas with Order No. 451, June 6, 1986.
[28] The spot market has grown significantly; the New York Mercantile Exchange is promising a natural gas futures market soon.
[29] The FERC is approving various transportation programs; these programs promise to provide an array of options to nearly all consumers and producers.

Risks of Contracting

In a competitive world, many forces affect the value of one type of contracting over another. In considering the economic and political forces, each party to the contract must identify various risks--uncertainties to which their contracts are exposed. These risks must be evaluated in the light of the relative price of one contract form versus another.

This section briefly identifies the risks associated with alternative contracts for both gas supply and for transmission capacity. The contracts are examined from the perspective of both the buyer and seller; the LDC is singled out as the buyer of both supply and capacity. Investment literature suggests various risks that the investor must consider.[30] Of these, four appear critical to natural gas contracting. They are:

> Business Risk. Every business, including regulated firms, may lose earning power or usefulness because of competition, managerial error, or change in demand due to technological change or changes in relative prices. Income volatility is primarily a function of sales and price volatility.[31]

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[30] George Christy and John Clendenin, Introduction to Investments (New York: McGraw-Hill, 1983), pp. 8-11 and Frank Reilly, Investment Analysis (Hinsdale, IL: Dryden Press, 1985), pp. 15-19.

[31] Another dimension of risk is the method of financing. Greater reliance on external sources increases the financial risk. This dimension has been omitted from this discussion. Possibly the exposure to financial risk may encourage the producer to minimize business risk. Business risk for a regulated firm like a LDC also involves operating under known regulatory rules. (Social risk considers that these rules may fluctuate.) Business risk may involve least-cost gas supply rules, which prevent the pass-through of excessive costs. The LDC may face underrecovery. Further, high prices may cause the LDC load loss or even cause some customers to bypass its system. The latter is likely, both due to distribution or capacity costs and also to the cost of gas acquisitions. More end-users have the option of direct purchasing and using the existing facilities, than bypassing essential facilities.

Price or Rate-Level Risk. When a long-term price or rate has been specified at a fixed level or has a pre-set escalation formula this price or rate can differ from the current spot or short-term market price or rate. The price or rate level risk is that the long-term rate may not reflect the current value of the commodity or service. Selection of very short-term contracts would minimize this price or rate risk. However, short-term contracting solutions only confront the purchaser or seller with the other horn of the dilemma--an income risk, which was part of the preceding business risk.

Liquidity Risk. Liquidity risk is the uncertainty that a commodity or service once purchased cannot be resold. An active secondary market serves to reduce such risk. Resale of a commodity or of capacity rights has not been a major concern of the natural gas industry, unlike other investment areas where investors can buy or sell quickly. This dimension is becoming important in wellhead contracts as well as in contracts for transmission capacity.

Regulatory or Social Risk. This risk arises when regulation hampers an otherwise profitable investment. The natural gas industry, at least at the wellhead and city-gate, is evolving with less regulatory and greater business risk. The LDC is gaining more market options, but regulation continues and may change the criterion for full recovery of LDC costs.

Alternative contract forms carry different levels of risk. Several forms of contracts have been identified both for gas supply and for transmission capacity. The relative merits of these forms are discussed in the following section.

Wellhead Contracting

The four types of risks are examined under six forms of wellhead contracts for both producers and merchants. Tables 1 and 2 summarize the risks associated with these wellhead contracts from both the producers' and buyers' (whether pipeline or LDC) perspectives. Two extreme forms will be examined first: spot sales versus long-term and 100 percent take-or-pay with fixed-price escalation.[32]

Gas Producers

To gas producers, cash flow is the main business risk in contracting. There is both a price and a quantity dimension to cash flow. With open access and with an adequate spot market, there is less quantity risk with spot sales than with long-term contracts, even those that carry 100 percent take-or-pay. Under spot sales, producers, not buyers, decide the rate of production.

However, spot sales may carry greater business risk with regard to price; long-term fixed price contracts minimize this risk. The latter business risk reduction has its own costs.[33] These are two totally

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[32] Beside the risk dimension of alternative contracts, there may be a transaction cost aspect. High transaction cost previously was minimized by the use of long-term contracts. Yet, with open access and with liquidity, the transactions cost for a homogeneous commodity such as natural gas should be quite small. Hence, this aspect has been excluded as insignificant in the evolution of the form of future contracting.

[33] Contracting literature supports long-term contracts on the grounds that these contracts guarantee producers' cash flow--there is a known demand, not an estimated one. With a more certain cash flow, risks are lower, thus lowering financing costs and permitting a lower average selling price. There are varying degrees of truth to each of these relationships. First, when natural gas was in short supply, long-term contracts did guarantee cash-flow as would have any type of contract that was subject to open access. We are now in a period where purchasers have a choice. Uneconomically based long-term contracts are not entirely safe havens. While "commercial impracticability" requires

(Footnote continues on next page)

different dimensions of business risk and it is not possible to determine, a priori, which is greater. In the current environment, when pipelines attempt to walk away from fixed-price, long-term contracts, the latter price dimension may be dismissed by many producers. Some producers may be better able to enforce long-term contracts than others. These producers with leverage may then find long-term contracting advantageous; those without leverage may look to the spot market.

Another risk to the producer is that future market prices may exceed the contractual price in fixed-priced, long-term contracts. Opportunities to sell gas at a higher price may be missed with long-term contracts, but not with spot market sales. With spot sales, the producer is like a speculator. A particularly cautious producer may want others to take this price-level risk but in exchange will have to take a lower-than-average, long-term price. A risk plunger may wish to acquire this price-level risk at a low price.

With open access, liquidity risk is likely to be negligible for producers willing to sell in the spot market. With open access, the spot market has great depth, making this option available to producers whose contracts have expired or were terminated. Long-term contracts may have difficulty regaining similar terms should the existing contracts turn over. Current practices in the oil market have moved from near-term contracts giving producers a premium for guaranteed supply availability, to requiring producers to give a discount for guaranteed demand. This reinforces the fact that there is no typical

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(Footnote continued from previous page)

more than the contract being just not currently economic for this contract to be modified and hence long-term contractual terms carry greater revenue guarantee, there are costs to these revenue guarantees. First, there is the pure litigation expense. Second, the known demand was itself modeled by both parties. The buyer wants a discount from its modeled price trajectory. Insurance can be costly to the producer and have little worth. If you destroy the pipeline's downstream monopoly power, competition lessens its ability to provide premium payments above the competitive price.

TABLE 1

PRODUCER PERSPECTIVE ON SUPPLY CONTRACTING

Type of Contract / Risk of Contract	Spot Market	Long-Term Flexible Price Frequent Market-Out	Long-Term Flexible Price No Market Out	Long-Term Flexible Price tied to Oil No Market-Out	Long-Term Fixed-Price 60% Take-or-Pay No Market-Out	Long-Term Fixed Price 100% Take-or-Pay No Market-Out
Business Risk	Lower Q Risk Raises P Risk May Lower Income Risk	Raises Q Risk High P Risk	Higher Q Risk High P	High	High Q Risk Lower P Risk	Moderate Q Risk Low P Risk Low Income Risk
Price-Level Risk	No Price-Level Risk	Negligible Price Level Risk	Negligible Price Level Risk	Raises Price Level Risk	High Price level Risk	High Price Level Risk
Liquidity Risk	Low Risk	Low Risk	Some Risk	Moderate Risk	High Risk	High Risk
Social Risk					te Risk	Moderate Risk

TABLE 2

PIPELINE/LDC/MERCHANT PERSPECTIVE ON SUPPLY CONTRACTING

Risk of Contract \ Type of Contract	Spot Market	Long-Term Flexible Price Frequent Market-Out	Long-Term Flexible Price No Market Out	Long-Term Flexible Price tied to Oil or PL No Market-Out	Long-Term Fixed-Price 60% Take-or pay No Market-Out	Long-Term Fixed Price -100% Take-or pay No Market-Out
Business Risk	Lowers Risk of Serving Swing Markets Could Lower Risk by being Low Cost	Slightly Lower Q Risk & P Risk	Lowers Q Risk of Spot In-adequate	Lowers Q Risk if Spot Market Is In-adequate	May Lower Cost if Demand is Volatile and Spot Price Is High	Lowers Price Volatility Could Lower Risk By Being Low Cost
Price-Level Risk	No Risk	Negligible Risk	Negligible Risk	Moderate Risk	High Risk	High Risk
Liquidity Risk	No Risk	Negligible Risk	Little Risk	Moderate Risk,* Have Spot Market As Alternative	High Risk But Spot Market Is Alter-native	High Risk Spot Market Is Alter-native
Social Risk	No Risk	Little Risk	Little Risk	Moderate Risk	Moderate Risk	Moderate Risk

lower price over the long-term to be gained by buyers of long-term contracts.

Finally, the social risks with wellhead contracts are many. For example, regulators may again impose price ceilings or grant pipelines monopsony or monopoly power that allows pipelines to deny access unless certain concessions are gained. The possibility of social risk prevents producers from offering short-run concessions for longer-term gains in contracts, as the long-term contemplated may not arrive. Spot sales do not carry this social risk.

Gas Merchants

The merchant may be a pipeline, a local distribution company, or an unregulated entity. The business risk from wellhead contracting differs among these three. The pipeline's obligation is contractual, as is the unregulated entity's; however, the pipeline may feel regulatory or financial pressure to provide better service than the contract requires. This pressure may be directly expressed in regulatory proceedings or it may have been an obligation incurred during past debt financing that pledged some reserve to sale ratio. The LDC obligation is to serve all who ask for service. While certain noncore customers may be excluded in the future,[34] this service obligation still remains. It is unsettling to note, however, that even small customers may wish for their own gas supply should a price gap develop in the future. Of course, most individual homeowners contract individually for fuel oil.

The business risk for all merchants is that of income: can its acquisitions be sold to cover its operating costs and also yield a profit? The pipeline merchant may also want to ensure throughput, while

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[34] Recent action by the California Public Utilities Commission is significant. CPUC identified customers with an annual usage less than 25,000 Mcf as "core" customers. Further, large users who chose to use the LDC supply are "elect noncore" customers. CPUC considers the traditional utility obligation to serve is only for these core and elect noncore customers.

the LDC may be concerned with fulfilling its service obligation. Business risk should diminish when the merchant provides the lowest long-term mix of gas contracts. As the price falls, sales increase. Yet, the state regulatory commission may also charge the LDC (and, indirectly, other merchants who sell to the LDC) with providing price stability, an objective that could increase the long-term cost of gas.

Given the mutability of demand, the best mix of wellhead contracts would contain some spot purchases when long-term fixed price contracts have lower prices, but carry take-or-pay costs with them. These long-term contracts would provide the desired price stability. If, as our analysis has indicated, these long-term contracts are not necessarily the cheapest, the LDC could minimize costs with 100 percent spot purchases, thus risking PUC censure for price fluctuation. The LDC may need to purchase a mix that includes long-term, fixed-price contracts to provide necessary stability even when spot market prices are lowest.

Another dimension of business risk is that when wellhead prices are too high, sales are lost. If these contracts have take-or-pay clauses, a death spiral could develop with even higher costs and even lower sales. The spot market minimizes this business risk. At the other extreme, in periods when the spot market price is higher than the long-term contract price, there will not be enough long-term gas supplies to threaten spot market sales. The business risk of lost sales is minimal when the LDC relies upon spot market contracts.

The price-level risk refers to the selling price of the contract at its term relative to the current market price. Plainly the long-term, fixed price contract carries greater risk. A state commission may perceive benefits in accepting this price-level risk.[35]

The liquidity risk is greater with long-term contracts and negligible with spot contracts. With open access, gas supply is always available if the buyer is willing to pay the asking price. However,

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[35] The commission might be willing to accept certain slightly higher prices in current, long-term contracts to avoid the risk of very high future spot prices or to avoid price volatility.

additional supply may be available from end-users rather than producers. This liquidity holds for spot sales only. It is far less promising for those trying to quickly find or resell a long-term contract on similar terms.

The social risk for the regulated merchant is that the rules of the game may change, leaving it committed by contract to serve nonexistent customers. These rules are currently in transition; high risks exist for long-term, fixed-price contracts. There are penalties for breaking these contracts on the grounds of *force majeure*. On the other hand, there are also social risks of shifting to short-term contracts if the trend of relying more on competition and less on regulation is reversed.

Conclusion on Spot Versus Long-Term, Fixed-Price Contracting

The traditional long-term, fixed-price contract may, under certain conditions, carry a higher average price over the life of the contract than a series of spot market prices. These conditions are:

1. When producers see a high price-level risk associated with long-term, fixed-price contracts. (This perception is cyclical.)

2. When producers want more control over their rate of production and their cash-flow. (This occurs in all periods.)

3. When buyers want to pay a supply assurance premium. (This increasingly occurs when the adequacy of the spot market is uncertain.)

4. When producers do not want to pay a demand assurance premium. (This occurs when spot market volume is seen as adequate.)

5. When producers do not value the price guarantees under long-term, fixed-price contracts. (This may occur in periods of transition where social risk is also high.)

Each of the conditions above could change in different environments. Neither producers nor purchasers will always favor the traditional long-term, fixed-price contracts over spot market contracts. Only when additional assumptions are made about 1) the degree of price and income stability desired, 2) the efficiency of the spot market, and 3) the costs of upholding long-term contracts, can more definite answers be given.

The Relative Value of Flexible Long-Term Contracts

Long-term contracts can allow greater flexibility in three ways. First, the level at which take-or-pay is triggered can be lowered. Second, the price can be tied to the price of some other market. Third, the contract may have unilateral or bilateral market-outs.

First, greater take-or-pay flexibility increases the producers' business risk as cash-flow becomes less predictable, and the take of gas may be greatest when the price is lowest. At the same time, greater take-or-pay flexibility may lower the cost to the purchaser when demand uncertainty is great and when the customer has been relying on contracts with 100 percent take-or-pay. Thus, it is logical to expect that a premium, which may vary cyclically with the tightness of the natural gas market, would be paid for a lower rate of take-or-pay. Regulation that treats take-or-pay payments differently than gas costs may encourage the pipeline (and possibly the LDC in the future) to favor higher cost contracts with lower take-or-pay rates. Regulation, in fact, may encourage inefficient contracting.

Second, the inclusion of a flexible price provision lowers the price-level risk. This provision raises producers' business risk relative to fixed-price contracts and provides the LDC with a possibly undesirable price volatility. This dimension hinges upon preferences among producers, among buyers, and between these groups, and the effect upon average price is not certain. On the other hand, this provision lowers purchasers' business risk and raises producers'. Thus, a price premium would be expected. The optimal flexible price provision could be tied to the natural gas futures price on the contract closing date. Cash and futures prices usually coincide then. Further, there are usually five to eight contract periods per year. The futures market is most likely to have the greatest volume and be most representative. Linking the contract price to another natural gas price minimizes price-level risk. While gas price volatility may be similar to other fuels, it is unlikely to be identical.[36]

Third, the bilateral market-out makes the contract very similar to the spot market form. These more flexible provisions will yield a contract form that is, on the average, more expensive than long-term, fixed-price contracts. Further, since the spot price may have an average price below the long-term, fixed-price, 100 percent take-or-pay contract, in these and some other cases, the spot market provides advantages over these intermediate contract forms. The higher priced form of flexible term contracting will be observed when the liquidity of the spot market has not been proved, when the future is highly uncertain, and when regulators are biased against traditional long-term contracting.

The Best Merchant

The preceding analysis discussed the best contract form. This section examines the attributes of a successful merchant.

[36] Prior to the development of a competitively determined market price for natural gas, contract linkage with the price of residual or distillate was rational and probably promoted efficiency, given the deficient regulatory setting.

First, the merchant best able to project future demand will have a competitive advantage. With more certain demand, this merchant can rely more heavily on long-term, fixed-term contracts. To achieve this demand certainty, the merchant will have a specialized product, a supply package expressly tailored to customers who guarantee a certain future demand. At the same time, customers will group themselves into swing and stable classifications. The stable group will look to merchants who will tailor packages of supply expressly for them.[37]

Second, many different supply mixes are likely to be offered--each tailored to the customer's objectives. This does not mean that the pipeline cannot be the best merchant, but it does indicate that the pipeline as merchant will not survive unless it provides more than one supply mix. No one supply mix can be optimal for a majority of customers. Customers will seek out merchants who can improve upon a single package, given the customers' own preferences. Each LDC or end-user preference for supply (price, reliability, flexibility, price stability) will dictate the merchant's mix; multiple portfolios will be common.[38] Merchants will specialize: some will focus on one location or region, while others will be national in scope.

The recent trend has been toward using short-term or spot supply in a merchant's mix. As the disorder lessens or is perceived to end, merchants will begin to package a wider array of supply services. However, this does not answer the question of what affiliation this merchant possesses. The recent experience of Columbia Gas may provide a clue. Columbia Gas Transmission was the first major interstate pipeline to provide open access under Order No. 436. A new pattern of different merchants, each serving a different type of customer emerged. The very

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[37] The demand for gas by low-load factor customers involves either storage or variable rate of wellhead production. Yet, in an unbundled world they will pay these charges regardless. Their low-load factor does not prevent them from finding a merchant with a long-term, fixed-term contract mix for their special demand.
[38] This is the same megatrend that has prevented all telephones from being black, all bathtubs white, and all checks green.

large customers do their own merchandising, intermediate-size customers rely on an independent merchant (Yankee, Entrade, Hadson, etc.), while small customers rely on Columbia's own marketing affiliate. These patterns may change, and new merchants, possibly affiliated with producers, possibly more efficient, may enter the market.

The risk of price-level changes is likely to take its toll of independent merchants, and shift merchandising to the LDC or end-user. Brokerage, however, will flourish. The unregulated broker may fare best, as the small risk that price will drop can be offset by profits during an upswing.

Transmission Capacity Contracting

The four types of risks are examined under four forms of capacity contracts for both pipelines (sellers) and LDCs (one type of buyer). Tables 3 and 4 summarize the various advantages of one contact over another.

Pipeline

The cash flow of the pipeline hinges on its throughput and its rate, which is regulated in rate cases. In the past, as throughput has decreased, the pipeline has generally sought and obtained higher per unit rates. Further, until recently, revenue from transportation was generally credited back to its customers. The pipeline neither lost nor gained by transporting more or less natural gas. These regulatory policies reduced the pipeline's business risk.

Various regulatory policies affecting the pipeline's business risk are changing. First, the pipeline's recovery of its allowed rate of return hinges upon projected volumes, both of sales and transportation. Second, customers may not be held responsible for the entire portion of the pipeline if some capacity is unused. Third, contracts for capacity

TABLE 3

PIPELINE PERSPECTIVE ON CONTRACTING FOR TRANSMISSION CAPACITY

Type of Contract / Risk of Contract		INTERRUPTIBLE		FIRM	
		Unreserved	Reserved	Short-Term	Long-Term
Business Risk		Some Risk Revenue Needed to Lower Price of Firm Service	Lowers Risk Guarantees Revenue	Raises Risk Through Greater Uncertainty; Need be Competitive Lowers Risk If Gains Throughput	Lowers Risk; Could Decrease Cost of Debt, Lessens Death Spiral, Facilitates Market Segmentation Raises Risk; Not What Consumers Want
Rate-Level Risk		Low Rate-Level Risk	Low Rate-Level Risk Short-Term Contracting; Rate May Change	Low Rate-Level Risk; Ceiling Precludes Upside Potential, Selective Discounting Gives Downward Rates	Some Rate-Level Risk; But Long-term Rates Not Fixed, Flexible Within Rate Period, Change Possible In Rate Case
Liquidity Risk	Not Provided	Not Applicable	High Risk	Low Risk	Low Applicability (Effect on Business Risk is Uncertain - Increase Long-term Contracting)
	Provided	Not Applicable	Lower Risk	Low Risk; If Rates Are Competitive	High Risk but Effect May Lower Business Risk
Social Risk		Low Risk Rules May Change on Capacity Rights	Some Risk; Alternative Allocation Method May Not Have Revenue Guarantee	Some Risk; If Not Competitive	Lower Risk If Less Unused Capacity Some Risk If Customers Shit Greater Unused Capacity

TABLE 4

LDC PIPELINE PERSPECTIVE ON CONTRACTING FOR TRANSMISSION CAPACITY

Risk of Contract \ Type of Contract		INTERRUPTIBLE: Unreserved	INTERRUPTIBLE: Reserved	FIRM: Short-Term	FIRM: Long-Term
Business Risk		Lower Risk Possibly Lowers Capacity Costs	Lowers Risk Possibly Lowers Capacity Costs	High Risk Potential Capacity Becomes Book by Long-Term Customers High Liquidity Lowers Security Risk but Raises Business Risk	Lowers Risk; Meets Service Obligation Raises Risk; Excess Future Capacity, Non Least-Cost Rates In Future
Rate-Level Risk		Low Risk Minimal Rates	Low Risk Minimal Rates	Low Risk Variability Linked to Having Alternatives, not Just Short-term Contracts	High Risk; Long-Term Maximum Ceiling May Differ From Competitive Rate, Don't Get Discount
Liquidity Risk	Not Provided	No Risk	High Risk Open Access Lowers	High Risk; Open Access Provides Liquidity	Low Applicability (High Risk But Exposure Is Low)
	Provided	First-Come/First Served May Limit Applicability	Risk Increases if Can't Re-assign	Some Risk If Insufficient depth; Price Not Used To Ration Capacity	High Risk Resale on Similar Terms Unlikely
Social Risk		Lowers Risk of Serving Interrupt-ible [illegible]	Lowers Risk [illegible]	[illegible] may [illegible] tive	High Risk Regulator May Lower Security and Raise Cost-Effectiveness as Performance Criteria

may extend for a time period shorter than the time between a pipeline's rate cases. Fourth, interpipeline and interfuel competition may dictate selling capacity at a rate below the ceiling upon which the pipeline's revenue requirement was based.

Throughput, rates and revenue are more uncertain now; there is a potential profit from greater utilization and also a much larger downside risk. The opportunity to change rates within a zone of reasonableness, however, and to selectively discount does give the pipeline some new tools to reduce its business risk.

The business risk is least when all capacity is booked on a long-term basis and there is a waiting list for interruptible service. Not only is the pipeline fully used, but interruptible service may provide revenue that will lower the cost of long-term firm service. The opportunity to sell reserved interruptible service further lowers the pipeline's risk and may facilitate the allocation of interruptible service to those who value it most. Given the lower risk associated with long-term contracts, a lower rate might be expected. The pipeline could be expected to share this benefit with its customers.

If the pipeline is an essential facility, then it may see little reason to discount to gain customers, as its customers highly value long-term contracts. In fact, a pipeline may intensify an LDC's need for long-term contracting by not providing liquidity. If the pipeline is not an essential facility, business risk is very much related to its relative competitiveness. Interestingly, by providing short-term service, the pipeline may lower the consumer's risk and increase its attractiveness relative to any competitors.[39] Further, greater throughput of high value service may be gained. Both can cause the pipeline's business risk to decline. Interruptible service is again

[39] The transaction costs in capacity contracting are usually small. This is not a complex transaction as the commodity and service are homogeneous. The transaction is subject to frequent turnover; a certain amount of goodwill is needed on both sides, that may make this type of contracting self-enforcing.

desirable. The contract form that minimizes the pipeline's business risk is related to the structure of the market it serves.

The pipeline's business risk is minimized in other ways if a large fraction of its capacity is committed to long-term contracts. The possibility of a death spiral (lower throughput, higher rates, even lower throughput, etc.) is reduced, and there is less need for short-term, selective discounting. Traditionally, long-term capacity contracts have the highest rates. A pipeline might consider granting a specific discount for long-term contracts if its cost of capital is reduced thereby. There is cost-based rationale for more than one rate, depending on the duration of the contract.

Rate-level risk is that long-term rates will deviate from short-term rates. This risk is lower with long-term capacity contracts than with supply contracts since capacity rates are flexible, changing with rate cases and, between rate case periods, changing within a zone of reasonableness. Given that the pipeline's rates are subject to a ceiling, this rate-level risk in a rising market may not be critical since the pipeline's profits are limited by the ceiling. Rate-level risk from a shortage of customers is reduced if rates can fluctuate within a range. Again, this risk exposure is connected to the monopoly power of the pipeline and the social risk that the regulator will declare the pipeline to have unused and useless capacity.

Currently, there is negligible liquidity in the market for firm transportation capacity. There is some liquidity for interruptible service, and this secondary market could grow with flexible receipt and delivery points. Without liquidity, there is a high risk of insufficient capacity when needed. This causes security-conscious customers to contract for firm transportation on a long-term basis based on their highest perceived need. If the capacity market had been liquid, these customers could contract less, increasing their reliance upon the spot market for capacity. Spot capacity price in peak periods would be greater than the long-term capacity price.

When capacity is easily provided by new entrants, or when the pipeline has excess capacity, a pipeline may wish to introduce liquidity to its system to gain customers. This liquidity may increase throughput, lowering the pipeline's business risk, as the pipeline is now providing superior service from the customers' viewpoint. With open access, liquidity may develop even without the pipeline initiating it. LDCs can make contracts with others on the pipeline, and with flexible delivery and receipt points, one party's capacity can be reassigned to another party. The highest bidder can obtain capacity.

The social risk to the pipeline increases if the pipeline relies on its market power, possibly gained through regulatory rulemaking. What the regulator gives, it can take away. Even the most competitive pipeline may prove less profitable than planned because of regulatory impediments limiting the full competitive gains. Still, the shock of new regulation is likely to be less for a competitive pipeline. This reasoning suggests that the contracting form that best meets consumer needs at the lowest cost will minimize social risk for the pipeline.

Local Distribution Company

The business risk to the LDC hinges, in part, upon its service obligation. The LDC is a regulated utility with an obligation to provide service upon demand. There is no written contractual relation with its customers, merely an implied duty. The LDC has focused on security and the ability to meet peak needs. However, as customer demand becomes more elastic (LDC bypass, fuel switching) and the state regulatory body becomes more cost conscious, the business risk of the LDC increases measurably. Excessive transportation bills either from contracting for too much or at too high a rate may trigger prudence inquiries more often than would curtailing some customers because of too little capacity.

The LDC lowers its business risk through long-term contracting only with respect to its having adequate capacity to meet its service obligations. This assurance may come at a very high price. First, some of the LDC customers may leave its system, either through bypassing, fuel-switching, or plant closing. The LDC cost for capacity contracts must be spread over fewer customers, resulting in a higher margin and possibly even greater load loss. Second, some of the pipeline's other customers may leave the pipeline's system. The pipeline may get FERC authorization for higher average rates; the LDC with a long-term contract is exposed to these higher rates. Further, there are secondary repercussions that could lead to even higher rates.[40] Third, the pipeline rate for capacity is flexible and can be selectively discounted. The LDC with a long-term contract may not benefit from the discount as its flexibility is impaired in the near-term. These three factors may result in the state regulatory body taking a dim view of long-term contracting.

Additionally, excess capacity may develop on many pipeline systems. This may happen because of more rational rate design, more backhaul and exchanges, and the new entry of interconnecting legs that increase efficiency. The LDC must expect that discounts like those in the airline industry may develop in the natural gas transmission industry. Further, the need for long-term contracts because capacity was not allocated to the highest bidder is gone. The LDC has a large rate-level risk from having a 10- or 20-year contract or an exclusive transportation contract unless concessions were gained originally. An LDC takes a tremendous social risk that the state regulatory body will disallow the recovery of some part of its long-term capacity contract costs.

The LDC must analyze pipeline capacity contracting just as it did gas supply. This is especially important if there is excess capacity on the pipeline systems or if some liquidity has developed. The LDC must also evaluate whether the short-term capacity rate is lower on average than that of long-term contracting. (The latter includes the long-term

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[40] Natural gas sales will probably rise rather than fall in the future. Despite this, the natural gas transmission industry may have its Braniffs.

rate plus the average cost of excess capacity.) The short-term rate is usually lower, but the long-term rate may provide greater rate stability--a desirable attribute.

Short-term contracting can lower the average capacity costs in three ways. First, a lower average amount of capacity is contracted for. Second, if there is excess capacity, and interpipeline competition emerges, discounts will be available. Those LDCs that have the option to come on or leave are the ones most likely to obtain discounts. Third, interruptible customers are likely to give up capacity as their rates approach firm service levels. An LDC wanting additional firm capacity at peak periods should be able to obtain it at a rate close to the long-term firm capacity rate. Only if liquidity is absent and if capacity is assigned by factors other than price would short-term capacity be unavailable.

Least-cost capacity contracting clearly requires some mixture of short- and long-term contracting. Further, this mix also hinges upon the pipeline's discounting the rate for long-term capacity contracts.

The LDC may be reluctant to rely on short-term capacity contracting if firm capacity is expected to be scarce in the future and liquidity is lacking. In the past, at times when pipelines have been full, much, though not all, interruptible service behind LDCs was being met. The pipeline company has little reason to undersize its pipe when this means raising the average unit cost and denying firm service at the maximum rate. At the same time, there is risk in having excess capacity. The LDC may be willing to pay for capacity assurance, if it is needed, and it is not too costly.

Given a choice, an LDC will favor the pipeline's short-term contracts, if other factors are equal. Short-term contracts lower the LDC's business risk, rate-level risk, and social risk. The pipeline company will try to minimize its own risk and increase its throughput by discounts for longer-term service.

An LDC without storage or interruptible load can acquire flexibility by contracting with pipelines that have provided liquidity.

The amount of long-term capacity to contract for becomes more certain, but this will only be translated into long-term contracts when appropriate rates are available.

An LDC can use interruptible transportation only if the pipeline has excess capacity or if the LDC has sufficient storage facilities to accept gas at odd times. Interruptible transportation could help reduce the cost of capacity contracts in these cases. Interruptible capacity can always be acquired for the LDC noncore customers who prefer this level of service. However, interruptible customers are useful in filling in some firm contracted demands when demand by core customers is cyclically low. Further, if the pipeline does not have peak and offpeak rates, interruptible transportation may be particularly useful in off-peak periods in filling LDC storage. Such possibilities may encourage the pipeline to adopt seasonal rates as proposed in Order 436.

The above discussion suggests that it may be unwise for an LDC to sign a 10- or 20-year exclusive transportation contract under a 436 settlement for its prior contract demand levels. The LDC is accepting high risk without a rate reduction to offset these risks. Future proceedings at state commissions may identify this risk. Social regulation may apply to the gas utility's reserve margin and least-cost plant standards similar to those formerly applied to electrical utilities.

Conclusions on Best Mix

The optimal form of capacity contracting hinges on whether pipelines and LDCs are tightly regulated in the future or whether they will be given options. The analysis indicates that there are high risks to the LDC and the pipeline of maintaining only long-term contracting options for capacity. Interpipeline competition will be profitable to an LDC that stays flexible and to a pipeline that offers flexibility. Flexibility can lower cost and the risk exposure.

If costs remain important in the future, the current competitive trend in the natural gas industry is likely to continue. Competitive forces, not regulators, are overturning long-term contractual relationships. Until long-term capacity contracts are discounted, short-term contracting will be preferred, particularly by the LDCs. An LDC that does not recognize this exposes itself to high social and business risk. Its stockholders, in effect, may pay some of the costs associated with its current capacity contracting practices.

Implementing New Contracting Practices

The preceding analysis suggests that new circumstances will change contractual relations for gas supply and transmission capacity. This section reviews some strategies suggested in the literature and then examines contracting practices by electric utilities for coal and oil to see if these strategies are already employed elsewhere. Also, state commissions' policies to encourage LDCs to maximize consumer welfare are examined. While a wide variety of incentive policies developed by state commissions for the operation of electric utilities appear easily transferable to gas distribution, a more competitively determined standard appears useful for gas utilities.

LDC Gas Purchasing Strategies

Several articles have presented mathematical algorithms guiding gas supply acquisition. The objective functions differ: Decision Focus, Inc. uses a pure cost minimization,[41] Schlesinger uses a minimization of the non-recovered purchased gas costs,[42] and this paper posits a cost

[41] Dale Nesbitt, Determining the Best Mix of Supply Contracts in the Face of Uncertainty: An Application in the Gas Industry (Decision Focus, Inc., May 1985).
[42] Benjamin Schlesinger and Associates, Gas Utility Supply Planning and the Direct Sale Market: Key Issues and Risk Implications (American Gas Association, draft, April 1986), pp. 21-43.

minimization subject to some price stability over time.[43] The solution to all these formulations is a mixture of gas supply contracts. Further, the possibility that customers may purchase directly from producers may increase the fraction of spot purchases in the mix.

State commissions need to state clearly what the rules are--not only the objectives that the LDC should pursue but also the extent that the state commission will permit customers or groups of customers to purchase gas from alternative merchants.[44] There may be no necessary core market for LDC gas supply. Long-term, fixed-priced contracts will be good bargains in some periods and appear onerous in others. The state commission may require a regulated LDC, in large part, to pass any gains through to burner-tip customers.

The analysis so far generally has focused only upon gas supply purchasing strategies and not upon capacity contracting. This focus is consistent with the popular attention given to the gas bubble, but misses the new options of FERC Order 436. Contract demands can be converted from long-term sales to short-term transportation, contract demands can be reduced altogether or reduced on one pipeline and increased on another. While some pipelines may be traditional natural monopolies, others are not and monopoly positions gained through regulation are being phased out. Many LDCs have supply choices or will have them in the future. Capacity contracting can also be analyzed, using optimization techniques.

The mathematical methodology and assumptions on contracting developed by Decision Focus, Inc. are based on traditional

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[43] My evaluation found that spot market purchases could have a lower average price over an extended period. This differs from the implications of the Decision Focus, Inc. analysis. Yet, a similar mathematical analysis would be needed if minimal price volatility were also required.
[44] The individual homeowner does not have to join a co-op, but can contract for fuel oil directly. This should serve as a warning to those who think only industrials will bypass the LDC.

optimization.[45] Long-term, fixed-term contracts are assumed to be cheaper than long-term contracts with flexible take-or-pay provisions and both are cheaper than spot market acquisitions. If demand were certain, the utility would use only long-term, fixed-term contracts. However, with demand uncertainty, the utility has an incentive to acquire better information. It can use some flexible take-or-pay contracts, and rely on spot market supplies in addition to the lower-cost long-term, fixed-term contracts. This lets the merchant minimize take-or-pay costs and total average gas costs.

Schlesinger, on the other hand, assumed that the state regulatory commission would hold the distributor responsible whenever its average gas cost exceeded the lowest price available by a certain percent. Spot prices and spot gas availability were specified by a probability distribution with possible prices both below and above the long-term contract price. The utility needs some spot purchases to minimize the utility's risk of underrecovery and help it to maintain load. However, long-term contracting is also needed in order to have the utility meet its service obligation and to minimize costs when spot prices are high.

The assumptions of the Decision Focus, Inc. and Schlesinger studies can be questioned on several grounds. First, supply reliability can be achieved through reliance upon the spot market. Second, spot prices may be lower on the average. Third, the state commission's emphasis on price stability is likely to soften any rigid standards such as nonrecovery of gas costs above some percent of the lowest gas supply available. If the state commission does not emphasize price stability, spot market contracting may emerge as the truly dominant contract form.

[45] These mathematical algorithms were first developed for electrical utilities in the contracting and plant operations under a grant from the Electric Power Research Institute.

If the state commission sets a least-cost standard, it may exercise better control over natural gas cost than the FERC.[46]

Contracting for Other Energy Supplies

A comparative analysis of contracting practices for other energy forms and their transportation helps explain the changes occurring in the natural gas industry. It is difficult, however, to identify the exact reasons for contract differences. Some insights are possible by examining the regulated electrical utilities and their coal and oil contracting practices and also by considering unregulated fuel oil merchants.

Electric Utilities

Long-term contracts for coal supplies are commonly used by electric utilities. There are several reasons for this. First, coal is a substance with much variety in its ash and sulfur content, and its heat properties. Electric utilities usually tailor their coal-burning power plants to the qualities of their contracted coal. This unique matching of coal type with boiler design increases operational efficiency. There is, however, no large demand in the spot market for any one type of coal. This permits opportunistic behavior and creates the need for long-term contracting. Second, coal prices have been relatively stable, which reduces price-level risk. Third, fuel adjustment clauses have decreased the utilities' need to minimize coal purchase costs. Fourth,

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[46] Pennsylvania has a new state statute that requires the use of a least-cost fuel purchasing strategy. The Pennsylvania Commission has used this statute to disallow certain operating expenses of Equitable Resources, Inc. Courts have not held that this exercise of authority violated the commerce and supremacy clauses of the U.S. Constitution nor did the NGA and NGPA give the FERC exclusive jurisdiction. Docket No.85-5778. (3d cir.)

coal accounts for less than 30 percent of final costs as opposed to 60 percent for natural gas.

Coal contracting by industrial boiler-fuel users differs. Here, reliance upon short-term or spot transactions is typical. The main reason is their use of off-the-shelf boilers that can use a wider variety of coal. There may be some loss of efficiency, but this is offset by greater flexibility and possibly lower coal costs. The spot market is well suited to respond to demand variety of this sort.

Electric utility contract terms for oil, on the other hand, are becoming shorter. In the 1970s, 10-year contracts with relatively fixed take-or-buy and with price tied to posted crude oil prices were common. During this period, various governmental allocation schemes were promulgated that denied spot-market access to various parties. This was also a time when many electric utilities had low reserve margins. At least in the short-term, some utilities have large reserve margins and the government has deferred to market solutions driven by price. Both factors enable the utility to make greater use now of short-term contracting.

Fuel Oil Merchants

These firms are unregulated. Some are vertically integrated; others are not. While oil producers' contract forms are almost universally short-term, the merchant may have a contract as long as 2 years with a large end-user or with its jobber. Discounts are available for such intermediate contracts compared to spot market prices. There may be somewhat greater price stability in 2 year contracts, but any such advantage is small since all contracts typically have flexible terms. Consumers have accepted price volatility without demanding regulatory intervention, or have paid a premium to someone who would give them stability.

Incentive Plans

State regulatory commissions have shown an increasing dislike for automatic fuel adjustment clauses.[47] These clauses were used in the 1970s for both electric and gas utilities to minimize the impact of energy input price variability. Energy input prices were rising rapidly and unavoidably; fuel costs as a percentage of total costs rose from 20 to more than 60 percent. Fuel adjustment clauses reduced the need for long and expensive rate cases. Further, interim changes in fuel costs could exceed utility earnings; interim reliance on debt could raise the cost of capital and, accordingly, consumer costs.

Theory and Evidence

Current research suggests that the use of fuel adjustment clauses causes electric utilities to select an input mix that uses more fuel relative to capital and labor than is optimal because incentives to minimize fuel costs are dulled.[48] Scott indicates that utilities without fuel adjustment clauses during the 1965-1974 period were more successful than those with such clauses is avoiding rapid increases in the price of coal during the subsequent 1973-1978 coal shortage.[49] Negotiation of tighter contracts, better enforcement, monitoring, and contingency planning may be among the reasons for their success. Golec

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[47] Joseph Golec, An Incentive Based Fuel Adjustment Clause for Electric Utilities (Springfield, IL: Illinois Commerce Commission, 1986), p. 7.
[48] For example, see: David Baron and Raymond DeBondt, "Fuel Adjustment Mechanisms and Economic Efficiency," Journal of Industrial Economics, 1979, pp. 243-261, and John Kendrick, "Efficiency Incentives and Cost Factors in Public Utility Automatic Revenue Adjustment Clauses," Bell Journal of Economics (Spring 1975):299-313, and Mark Isaac, "Fuel Cost Adjustment Mechanisms and the Regulated Utility," Bell Journal of Economics (Spring 1982): 159-169.
[49] Frank Scott, "An Analysis of Fuel Adjustment Clauses," Ph.D. Dissertation, University of Virginia, 1979.

suggests that this is not surprising, since without adjustment clauses, the utilities stood to suffer more from cost increases.[60]

Purchased Gas Adjustments (PGAs) by an LDC pass on the cost of gas outside of its control. These include both gas supply and capacity costs. While many state regulatory bodies have focused on the electric utility's reserve margin, often disallowing the unused portion of its plants in its rate base, they have neglected gas distributors' transmission contracts; an LDC may be contracting for excessive capacity. Further, given that new interconnections and supply acquisitions involve capital and labor costs not currently covered by PGAs, LDCs have had minimal incentives for supply or capacity switching. This is identical to an observation about electrical utilities made by Kaserman and Tepel.[61]

Regulatory boards may find it difficult to condemn past decisions of electric utilities. Instead, they are drawn toward creating incentives for efficient purchasing by dropping PGA mechanisms, for example, instead of imposing after-the-fact penalties.

Golec suggests two principles that support this incentive approach.[62] First, the private sector firms provide management incentives to minimize purchasing costs. Second, when a utility has some input costs covered by an adjustment clause and has other inputs set in a rate case, the utility will deliberately overspend on the former to minimize the latter. For these reasons many state regulatory bodies prefer incentive approaches now.

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[60] Golec, Fuel Adjustment Clause, p. 10.
[61] David Kaserman and Richard Tepel, "The Impact of the Automatic Adjustment Clause on Fuel Purchase and Utilization Practices in the U.S. Electric Utility Industry," Southern Economic Journal (January 1982): 687-700.
[62] Golec, Fuel Adjustment Clause, p. 17.

Incentive Plans Adopted for Electrical Utilities

Some states have abolished automatic fuel adjustment clauses, and have changed from an historical method of setting base rates to a future test year approach using fuel cost projections. Other states have retained adjustment clauses, but restructure them to include some profit incentive for shareholders. For example, utilities may be allowed to keep only a portion of the difference between forecasted and actual fuel costs. Consumers receive the other portion. The states of New York and Oregon, as examples, have changed their fuel adjustment clauses to allow utilities to keep 20 percent of the difference between forecasted and actual fuel costs. Arkansas, California, Delaware, the District of Columbia, Florida, Maryland, Massachusetts, New Hampshire, North Carolina, Ohio, and West Virginia have introduced other types of incentives into their fuel adjustment clauses.

The Missouri Public Service Commission released a survey of the incentive plans employed by state regulatory bodies.[53] The survey shows that 30 states have incentive programs, while many others are considering them.

The results of these various incentive schemes point to several conclusions. First, many states find that the utilities seem to perform better under incentive schemes. This may be more apparent than real. Many states use both penalties and rewards, while others use only penalties. Several states report it is difficult to determine just how many of the changes in utility performance are due to incentive plans versus the multitude of other factors that affect performance. Those states that use prudence reviews have found imprudence difficult to prove.

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[53] Task Force Report on State Incentive Plans for Electric Utilities, Missouri Public Service Commission, March 20, 1985.

Implementing a Competitive Standard

There are several basic approaches to the recovery of gas costs. As noted above, one approach is the traditional test-year ratemaking, where costs are projected in advance and the utility is at full risk for changes in those costs. Unforeseen changes may be random (as with weather) and may place an unreasonable burden on the utility, particularly when there is great fluctuation in these costs. This procedure puts great emphasis on accurate forecasting, or, more likely, gamesmanship in forecasting, but may establish an incentive for the utility to minimize gas costs.

Contracting for a long-term, fixed-priced gas supply allows the LDC to minimize its risk under traditional test-year ratemaking. This traditional approach encourages the utility to minimize its risk-exposure and, only as a side effect, to minimize its gas costs. A state PUC could justify such an outcome if its primary objective is price stability, a rather soft standard.

Another approach would permit only a percentage of gas costs above the forecasted cost to be passed on to consumers, on the grounds that distribution utilities would be placed at great risk if exposed to the full cost variance. Such a risk otherwise could raise the cost of capital.

The most recently used approach passes all costs on to ratepayers through balancing accounts, at both the federal and state levels. This approach does not require forecasts, but it unfortunately has the effect of removing incentives to reduce costs. Only when customers have competitive options are they certain that the PGA mechanism is not being abused; the regulator with a detailed record of every transaction cannot duplicate the discipline of such competition.

Another approach would be to tie the recovery of gas costs to an external index of gas costs. If the index reflects competitive market valuation, it would be highly desirable. It would provide an incentive for cost reduction, end the need for forecasts, and protect the utility against being held responsible for fuel cost changes beyond its control. The appropriate index would be based on a market with enough buyers and sellers so that its price accurately reflected competitive market forces. The parties would not be only other utilities, but private sector firms with greater incentives to minimize gas cost. Currently only the spot market is suitable, but the developing futures market may be even more appropriate.

Spot Market Price as a Competitive Standard

This analysis recommends that state regulatory bodies institute a billing mechanism for natural gas supply whereby the ratepayer is initially billed only the spot market price. The LDC's purchase gas cost would not be the basis for the consumer bill. Further, the difference in the LDC's purchase gas cost and the spot market price would be retained by the LDC as its reward (or punishment) for the decisions it made in gas contracting. This difference could also be split among the LDC stockholders and ratepayers to lessen the risk exposure to the utility and to permit the ratepayer to share in the benefits and costs of gas contracting.

The use of a spot or futures market price as an index makes distributors responsible for the difference between their own costs and those of the index and raises three questions: 1) can the distributor gain above average profits under this standard, 2) how can price volatility be checked, and 3) will this standard bias gas supply contracting inappropriately toward spot contacts?

First, spot market prices may be the lowest available. In any period, there is difference of opinion about whether spot prices will go up or down and on the relative attractiveness of the terms in long-term contracts. While a mixture of long-term, fixed-term contracts acquired in a depressed market with spot purchases from other periods would probably yield a lower cost mix than a 100 percent reliance on the spot markets, it is difficult to predict how far down a market will go. The management of the utility may well claim any return gained from such ability. This strategy will always require the payment of a premium over the currently depressed spot market price; this premium will be needed to induce the gas producer to sign a long-term, fixed-term contract at that time. The utility would be accepting lower returns in the short-run under this proposed approach but would be speculating that the contract would be cost effective in the long-term. Of course, the ratepayer wants its utility to be clever and full of foresight.

Second, there are two levels at which price volatility can be measured: at the wellhead and at the burner-tip. Long-term contracting with fixed terms may increase price volatility at the wellhead while lessening it at the burner-tip. Greater wellhead price volatility results from long-term, fixed-term contracts that allow new or renegotiated contracts to capture much of this residual. This suggests that long-term, fixed-price contracting does not provide as much burner-tip price stability as previously thought. Once the futures market develops, the utility will have an additional tool to reduce short-term price volatility.

Third, the use of a spot market price in the consumer's bill will not inappropriately skew wellhead contracting toward the spot market. LDCs and their merchants would have every incentive under this standard to contract on a long-term basis whenever they perceive this contracting is cheaper over the longer term and to use any other contract form which may be superior, for that matter. Plainly, this standard increases the risk to an LDC, but the allocation of risk upon those making decisions is an appropriate regulatory tool to ensure contracting that minimizes gas costs.

To ease price volatility at the burner-tip, a utility could offer an alternative monthly billing mechanism similar to life-line rates. For these customers, the distributor would bill on a multi-year budget plan with partial annual adjustments as needed. The utility would keep a deferred balance account on which it could draw interest in periods of deficit. The customer would elect a rate design and would not easily be able to change. This alternative rate design would relieve some hardship for those on fixed incomes, nullify political pressure, and give the distributor greater flexibility in pursuing a cost minimizing wellhead contracting strategy.

Conclusions

This study has evaluated contracting practices for both gas supply and transmission capacity. Particular emphasis was placed upon LDC perspectives and options. Two changes in natural gas regulation have substantially reduced the need for long-term contracting: 1) the decontrol of wellhead prices and 2) the opening of transportation access. Opportunistic behavior, supply shortages, and exclusive certificates are no longer typical.

Despite recent changes, the natural gas industry will continue to need long-term contracting for both supply and capacity. Such contracts will be judged by different criteria now, however, before regulators will conclude they are more appropriate than flexible purchasing on the spot market.

Evolution within the industry has also placed the state regulatory body in a more pivotal role in setting natural gas prices at the burner-tip. This study suggests that competitive spot-market prices and least-cost strategies for purchasing transmission capacity be used to judge the effectiveness of LDC contracts. Further, LDCs should be rewarded for purchasing performance that is better than the spot-market price and penalized for performance that is more costly. What remains after these fundamental changes is a largely a self-regulating industry structure that should benefit the consumer.