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STATE REGULATORY CHALLENGES FOR THE NATURAL GAS INDUSTRY IN THE 1990s AND BEYOND

by

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FOREWORD

As part of its Occasional Paper series, the NRRI from time to time commissions reports from outside experts. Occasional Paper No. 15 represents one such report, prepared by David B. Hatcher and Arlon R. Tussing. This report looks at the changes that the natural gas industry will likely encounter over the next several years. These changes have important implications for state public utility commissions, which the authors discuss in detail.

We believe that the report offers our clientele an objective and timely writing on a topic that is highly pertinent. As with all NRRI contract publications, this report does not necessarily reflect our views or opinions on its content.

Douglas N. Jones
Director, NRRI
Columbus, Ohio

May 11, 1992

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1. INTRODUCTION

This report examines the natural gas industry from the perspective of the regulatory challenges that will confront state utility regulation in the 1990s. It identifies the forces driving the industry's economic evolution, and in turn, the changes in regulatory institutions that will be required if the industry is to perform efficiently and to the public's satisfaction.

The report is forward-looking, yet in only minor ways is it speculative. For reasons that will be apparent, we can safely assume that federal legislation and regulation will continue in the same direction they have been evolving during the past fifteen years.[1] It is equally reasonable to assume that the technical developments driving the pattern and volume of natural gas consumption over at least the next five to ten years can be identified and appraised without heroic conjecture or the need for special powers of foresight.

Even if these assumptions regarding future changes in federal institutions or impact of technology on natural gas usage turn out to be inaccurate, the major themes that will infuse the conflicts and choices facing state regulators are nevertheless already apparent at the federal level. In one set of discussions, therefore, we use these themes as a framework to organize certain issues that will appear at the retail-sales end of the industry, where regulation of gas distribution utilities (generically, LDCs) by state administrative bodies (generically, public utility commissions) plays the major role.

We have organized a second set of discussions around regulatory policies that originated at the retail level. These initiatives occurred independently of specific federal legislative and regulatory developments and independently of changes in industry structure occurring on a

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[1] As the authors were preparing this report, the Federal Energy Regulatory Commission (FERC) completed what it maintains is the final major rulemaking in its effort to make nondiscriminatory carriage available to customers on all federally regulated natural-gas pipelines subject to its jurisdiction. The elements of this rule (formally known as Order No. 636), with one notable exception, are logical and long overdue codifications of the "open-access" transportation policy first introduced by the Commission in 1985 in Order No. 436. That exception is the Commission's policy with respect to customers' rights to resell transportation service they have purchased from a pipeline but have temporarily ceased to need. This issue of transportation service resales is discussed at length in Section VII of the present report.

national or international scale. A common feature of these initiatives is that they tend to be outgrowths of regulatory innovations already applied to the regulation of telecommunications and electric utilities. Specifically, this set of discussions addresses retail rate design issues (including incentive regulation schemes), demand-side management (DSM), integrated resource planning (IRP) programs, and other attempts to reconcile regulatory practices affecting the gas and electric industries.

The final topic addressed in this report relates to natural gas as motor transport fuel, which occupies a growing place in national energy and environmental policy and represents a major potential expansion of the market for natural gas. This development accordingly confronts state regulatory bodies with decisions regarding the degree of integration or independence to foster between the emerging natural gas motor fuel delivery system and the existing gas distribution industry.

2. FOUR CRITICAL ELEMENTS TO UNDERSTANDING THE NATURAL GAS INDUSTRY

Element 1: Naturally Competitive Versus Naturally Monopolistic Economic Functions

The sale of natural gas as a commodity is both different and separable from the provision of natural gas transport and delivery services. The inherently competitive characteristics of the commodity market suggest that consumer welfare is compatible with and, indeed, is best served by deregulation of utility gas procurement. The market conditions that characterize gas delivery service, at least for captive customers, support a consensus in favor of continued regulation.

Element 2: Captive Versus Noncaptive Customers

The demarcation between captive and noncaptive ("core" and "noncore") gas users is substantial and durable enough to serve as a critical dividing line in public policy. Combining this distinction with that separating inherently competitive gas sales activities and naturally monopolistic transport services, there are logical implications for the way in which an LDC's obligation to serve should be defined, and for the manner in which rates should be determined for service to the two customer categories.

Element 3: Spot Transactions as the Measure of Commodity Value

Markets have evolved sufficiently for spot prices to serve as de facto standards for establishing the value of natural gas. That role will not diminish; indeed, gas sold in other types of transactions will generally reference the spot market as the basis on which the commodity's value in the nonspot transaction will be adjusted. This situation permits a radical simplification of the prudence or "reasonability" standards applicable to most LDCs' gas-procurement activities.

Element 4: Secondary Markets for Regulated Transport Services

Despite the remaining natural monopoly features of markets for gas transmission and delivery services and despite their continued economic regulation, such markets can function nearly as efficiently as unregulated, inherently competitive markets provided liberal rights exist to resell or trade in the regulated services. The regulatory implications of this insight include the need to remove federal inhibitions on the operation of a secondary market for such services. As of the date of this writing, however, the Federal Energy Regulatory Commission (FERC) has yet to grasp these implications fully. The need for such a secondary market, however, assures that it will thrive in one distorted form or another until federal rules fully accommodate it. State regulatory bodies thus will have to acknowledge such institutions in the regulatory standards they impose on LDCs.

These four elements are the fruit of changes that occurred in the structure of natural gas markets after passage of Natural Gas Policy Act in 1978. Together they constitute the principal themes underlying the regulatory challenges confronting state regulators in the present decade and beyond.

Since the mid-1980s, regulators have generally acknowledged (even if the full implications were sometimes unclear) the first two elements, namely, a distinction between gas and gas carriage and the existence of a noncaptive customer class. They frequently cited these demarcations in requiring or approving (a) unbundled open-access transport and delivery services and (b) rate flexibility for utilities so that they might retain noncaptive customers.

The third element--the role of the spot market--has been impossible to ignore, but its logical regulatory implications are still frequently misunderstood or overlooked. Distribution companies and their regulators, moreover, have accepted the role played by the spot market only belatedly and grudgingly, perhaps because it has tended to expose the mistaken business judgments and flawed oversight of those that previously executed or approved long-term, market-insensitive contract commitments.

The fourth element--emergence of secondary markets in transport and delivery services--has been identified and debated for several years, most noticeably at the federal regulatory level. FERC's long-term attempt to restrict or manage "capacity brokering" has forced the bulk of such secondary market activity into the gray market of "buy-sell" transactions that impose unnecessary costs on all transacting parties, and frustrate the means that state regulators would otherwise have available to impose simpler and more rational performance standards on the LDCs they regulate.

3. THE TRANSFORMATION OF THE NATURAL GAS INDUSTRY

The major structural changes in natural gas markets have driven and been driven by the regulatory evolution at the state and federal level during the 1980s. They continue to track that evolution into the 1990s. In decisive respects, however, those structural changes trace their origins to the Natural Gas Policy Act of 1978 (NGPA), which set in motion the eventual deregulation of natural gas first-sale or wellhead prices.

The phased decontrol of wellhead natural gas prices under the NGPA had a profound effect on the industry's structure. The buying and selling of natural gas as a commodity, distinct from its transportation, became a textbook illustration of near-perfect competition--thousands of buyers and sellers trading a homogeneous commodity at prices and according to contract terms that suited their separate needs. This reliance on the forces of supply and demand to establish prices, in lieu of government formulas or fiat, was the first of three preconditions for the emergence of a competitive gas procurement sector.

The second precondition was an end to the convention that any sale of gas in interstate commerce required the reserves and, indeed, the acreage from which that gas was produced to be forever "dedicated" to the particular sale. This dedication of reserves was imposed by the Federal Power Commission (FPC) notwithstanding any term limit in the sale contract or even the underlying production rights. Once the NGPA removed this reserve-dedication burden on new production, gas could be redirected from an original purchaser and use to a higher-value disposition whenever the occasion presented itself. Even where the original sale was under a long-term contract, the producer was now able to seek other buyers, so long as the first-sale purchaser declined to take available quantities at the agreed-upon price. These newly found abilities for natural gas to command a market price and to move where market opportunities revealed themselves were the foundations of today's competitive market.

The final prerequisite to full-blown competitive conditions in gas sales markets beyond the producing area, was the commercial separation of transport service from commodity sales at both the wellhead and the city gate. During the 1980s this "unbundling" of transportation services, and the provision of nondiscriminatory "open access" to them, dominated the natural gas regulatory agenda at the federal and subsequently the state level.[2]

[2] The sometimes significant but frequently trivial consequences of this unbundling policy have continued to dominate the current rulemaking attempts of the FERC, most particularly in the form of the so-called mega-NOPR. This latter rulemaking culminated in the issuance of Order No. 636 by FERC on April 8, 1992. For a commentary on this rule in the context of the long evolution toward mandatory carriage on a nondiscriminatory basis, see Arlon R. Tussing, *An Overview of FERC's mega-NOPR*, Conference of the Independent Petroleum Association of Mountain States (IPAMS) and the International Association for Energy Economics (IAEE), Denver, February 13, 1992. An earlier and more detailed history is contained in "A Perspective on Tomorrow: The Changing Structure and Regulatory Environment of the Natural Gas Industry." This paper was combined and adapted from speeches by the author to the Rocky Mountain Mineral Law Foundation Institute on Natural Gas Marketing, Santa Fe, New Mexico (May 14, 1987); the American Gas Association's 1987 Communications Conference, Atlanta, Georgia (May 20, 1987); and a Wisconsin Public Service Commission program on "The Evolving Natural-Gas Industry: Implications for State Regulatory Policies," Madison, Wisconsin (June 2, 1987). Adapted as "A Perspective on Tomorrow for the Changing Gas Industry," *Public Utilities Fortnightly*, October 1, 1987.

4. THE ISSUE OF TRANSITION COSTS

The negative repercussions pipelines attributed to the unbundling process flowed chiefly from the flawed gas-procurement decisions they made in the early NGPA years (albeit at the urging of or with the acquiescence of their distribution company customers and state and federal regulators), and would have soon manifested themselves even if the pipelines had not been required to offer their customers unbundled transmission services. These consequences, euphemistically termed the "contracts problem," or the "transition-costs" problem, were in the first instance the product of gas procurement strategies that ignored the possibility that energy prices (including market-clearing natural gas prices) might actually decline on a sustained basis rather than merely escalate at varying and unpredictable rates. They were only made worse to the effect that pipelines and LDCs didn't contemplate a situation in which their respective customers would be able to choose among gas suppliers.

Every sector of the gas industry thus entered the NGPA era overestimating the current market-clearing price of gas in North America, and underestimating the responsiveness of both supply and demand to higher prices. They accepted uncritically the then-fashionable notion that prices of competing fuels, driven by OPEC oil prices, would climb without limit. As a result, producers demanded and pipelines willingly contracted to pay "maximum lawful prices" prescribed by the NGPA, which for the new "deregulated supplies" exceeded the average wellhead price by figures ranging from 50 to 200 percent.[3] LDCs, in turn, communicated to the pipelines their intent--notwithstanding the ongoing price "flyup"--not only to take their historical purchase commitments, but to increase contract demand levels contained in service agreements with the pipelines.

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[3] See *An Analysis of Natural Gas Resources and Supply*, Energy Information Administration, U.S. Department of Energy, DOE/EIA-0481, October 1986.

Most producer contracts provided for formula price increases beyond NGPA ceilings after deregulation in 1985. The initial contract prices for some of those supplies (that is, NGPA Section 107 "deep gas") were four to six times the then-current average price.[4] Ironically, the pipelines thought they were getting bargains at such prices and in their frenzied competition to sign up new reserves committed themselves to "take or pay" for 75 to 95 percent of deliverable volumes--volumes that were seldom accurately forecast, and, in any event, that were beyond the buyer's control. Such contracts signed between 1979 and 1982 typically lacked any "marketability" or other escape clauses.[5]

Between 1981 and 1984, pipeline gas sales collapsed, in large part because of rising average acquisition costs along with the failure of oil prices to rise as forecast. First-sale contract terms were mostly unresponsive to these changing market conditions.[6] Take-or-pay liabilities of individual pipelines for gas not taken mounted into the billions of dollars.

Until the mid-1980s, few pipelines made a concerted effort to escape or fundamentally reform their problem contracts. Instead, industry decisionmakers sought to reassure themselves that *transient* phenomena, such as a run of unseasonably warm winters, a national recession, economic adjustments in the "rust belt," and a temporary glut in world oil markets had produced an equally transient gas supply "bubble" that would fade quickly when things returned to normal. Oil prices, many were confident, would resume their upward surge and gas demand would come booming back. Pipelines, with the reassurance of their LDC customers, believed they would soon need and be able to pay for the gas contractually committed to them, while producers believed that the volume and pricing terms in their contracts again would become enforceable.

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[4] See *An Analysis of Natural Gas Contracts, Volume III: Contract Provisions Covering Production of New Gas,* Energy Information Administration, U.S. Department of Energy, DOE/EIA-0505, May 1987: 15.

[5] Ibid., 11-15.

[6] Ibid., 25-34.

To the extent that the contracts problem might be more persistent and fundamental, the pipelines--wards of the state practically from birth--looked mainly to the FERC or Congress to rescue them by sanctioning the abrogation of the problem contracts, and to legitimize special billing arrangements allowing them to recover their extraordinary costs from captive customers. Throughout the 1980s, the gas industry and its regulators contemplated one remedy after another in attempting to mitigate and finally solve the "contracts problem." As of 1992, the damages from the imprudent contracting of 1979-1983 and the evasive temporizing in 1984-1988 nevertheless had yet to be completely reckoned.

Prospectively, however, the natural gas industry has adopted a remedy that guarantees against a recurrence of either a 1970s-type "shortage" or a 1980s-type "glut." That solution has been for pipeline companies in the role of regulated utilities to transform themselves from natural gas merchants--businesses buying and reselling gas--to transporters--businesses functioning in essence as common carriers.

In 1992, large portions of the take-or-pay liability remain to be recovered, as do portions of the producer-contract settlement costs which FERC's 1987 Order No. 500 allowed interstate pipelines to allocate to their downstream customers. The direct billing feature of Order No. 500 has worked its way through to the states, and few if any commissions and appellate courts are still pondering the legality of those directly-billed charges, or of their incorporation in retail rates. Although FERC's order suggested that commissions hold LDC shareholders accountable for a portion of these charges, as FERC held the pipelines' shareholders accountable for up to 50 percent, the general practice has been to permit gas utilities to recover the entire amount.[7]

FERC and the Federal courts winked at the fact that the market for natural gas would never have allowed pipelines and utilities to recover such charges from downstream customers, if regulation had not kept those customers captive. The states, in the person of attorneys general and their consumer-advocate divisions and the staff of the commissions, likewise conceded the battle. They did little to fight the FERC's proposals when they were first proposed in 1986 and exerted even less effort when it came to FERC's suggestion that the utilities might absorb a share

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[7] See "Current Status of State Commission Rate Treatment of Take-or-Pay Costs," *Gas Energy Review*, February 1991: 8-11.

of directly billed "transition costs." Imposing these costs on consumers must now be rationalized as the price they had to pay to be allowed to enter the new unbundled world of gas service. The time has passed when the transition-cost problem might have been differently resolved. The majority of states have projected, perhaps optimistically, that these transition costs would be fully amortized by 1994.[8]

[8] See Cynthia Marple and Anne Roland, *State Treatment of Take-Or-Pay Settlement Costs*, (Arlington, VA: American Gas Association, 1989). As this is written, FERC has defined new "transition costs" that pipelines under Commission jurisdiction are expected to incur in implementing provisions of Order No. 636. The Order provides, for example, that all of a pipeline's prudently incurred costs incurred in realigning its gas supply contracts under the rule may be recovered from its customers, in much the same fashion as take-or-pay costs under Order 500.

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5. THE DISTINCTION BETWEEN CAPTIVE AND NONCAPTIVE CUSTOMERS

The prior discussion of the separability of gas acquisition from gas carriage suggested that the former was an irrepressibly competitive function, whereas the latter was imbued with monopolistic features that conveyed market power to the service provider. This section inquires into the potential an LDC has for exercising its control over essential facilities for the purpose of extracting monopoly profits in the sale of its services.

Despite the appearance of scale economies in the long-haul transmission of natural gas, there have always been circumstances in which rivalry among or between competing pipelines was a natural outgrowth of the need to connect with alternative sources of natural gas. To reach such dispersed sources required a grid of pipelines that eventually traversed much of the eastern, midwestern and southern United States. For the major local distribution companies, the bulk of the gas transmission service they purchase is subject either to competitive sale or to the competitive pressure arising from a contestable market in which a new competitor can enter with only a nominal investment in connecting spurs from its mainline transmission system.[1]

By contrast, the distribution sector of the gas industry is substantially more monopolistic in structure. Even here, however, there are two major qualifications to the potential for economic inefficiency and social inequity that stem from what superficially meets simple criteria for monopoly power over deliveries within a geographic market.

A given distribution company may be a "monopoly," in fact, in the sense that its facilities are the only feasible means of moving gas to or from a given point. Or, it may

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[1] As of the mid-1980s, 75 percent of the gas delivered for retail sales was delivered to markets that were served by three or more pipelines. See Jeffrey J. Leitzinger, "Antitrust II: Future Directions for Antitrust in the Natural Gas Industry," *Natural Gas,* November 1987.

be a "natural monopoly" in that its system is capable of carrying incremental volumes to or from that point at a substantially lower expense than any new "stand-alone" or "bypass" facility.[2] However, there are circumstances in which such a monopoly position does conveys no significant market power if customers can obtain natural gas at lower cost to themselves by hooking up to another gas transport system (even if the hookup is technically redundant) or can dispense with gas entirely by substituting another fuel.

Some distribution customers can look to mainline transmission companies as viable competitive alternatives to their LDC. This situation has come to be referred to as the threat of LDC bypass. Even where the bypass threat is not carried out, it nevertheless offers customers the benefits of a contestable market. In short, end-users for whom bypass is an option are no longer effectively captive customers.[3]

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[2] Analysts have found it useful to distinguish two classes of customer-bypass situations, "uneconomic" and "economic" bypass. In either case, the customer is able to achieve a net reduction in its cost of gas supply by hooking up directly to a trunk pipeline, because the "stand-alone" cost of a direct pipeline hookup would be less than the incremental charges imposed by the LDC under its existing rates. Uneconomic bypass corresponds to a situation in which the added cost of the hookup is greater than the incremental cost *incurred by the LDC* in serving the customer. In this instance, the LDC could eliminate the customer's bypass incentive by reducing its rate to a level that still covers the incremental cost of serving the customer, but is less than the added costs the customer would incur in effecting a bypass. Economic bypass, in contrast, has no remedy in changed LDC rates (at least without a subsidy to the prospective bypasser), because it corresponds to a situation in which the added cost to the customer of the direct hookup is less than the amount by which loss of the load would reduce the LDC's costs.

[3] The immediate consequence of such circumstances has been to expose the flaws in traditional utility rate proceedings where "cost-based" rates have been calculated for aggregate customer groups according to "fully-allocated" costing principles. Where the computation of average system cost ignores the stand-alone cost of receiving equivalent utility service, the stage is set for a particular utility customer to install duplicative facilities but pay less than the "cost-based" rate. The customer disconnects from the LDC system and effects a distributor bypass. Its contribution to the distributor's fixed costs are lost and the facilities it duplicated now represent stranded investment that state regulators may or may not allow to stay in the utility's rate base.

Beyond bypass candidates, the existence of fuel-switchable loads has always meant that gas LDCs faced potential competition from alternate fuels. When natural gas prices were regulated far below the cost of oil and coal, this substitution option was rarely exercised voluntarily by the customer. Fuel switching occurred most frequently when the cheaper fuel--natural gas--was interrupted or curtailed, and when such service was temporarily restored. However, as gas prices began climbing in the late 1970s and alternate-fuel prices commenced falling in the early 1980s, fuel switching rapidly caused loss of markets for LDCs, particularly in heavy manufacturing areas. Wherever intense price competition from substitute fuels exists, the market power LDCs hold over such gas customers is dissolved.

At various phases of the business cycle and in the case of industries that are declining, growing rapidly, or that otherwise are in the midst of a radical restructuring, a third characteristic defines a further subcategory of noncaptive customers. That characteristic has little to do with the ability to substitute either an alternative source of gas service or an alternate fuel; rather it has to do with a customer's sensitivity to the business cycle, market conditions, or both within its own industries including the cost of fuel to its own plants elsewhere or to its competitors. In other words, there exist industrial customers--particularly those engaged in energy-intensive industries--whose levels of gas usage for practical purposes are captive to economic forces outside the influence of their LDC.

These three types of customers, representing noncaptive loads for the LDC, present a discrete and thereby solvable dilemma for state commissions: How can an LDC plan on procuring a secure and long-term supply of natural gas for a sizable customer base whose load requirements are unstable as well as unpredictable?

The answer is not only can the utility not plan on such a procurement, it *should not be permitted* to undertake such a purchase if there is any possibility that costs so incurred may be left for captive customers to assume when the noncaptive loads fail to materialize. Quite simply, then, the regulatory dilemma is solved by precluding regulated utilities from procuring gas for sale to noncaptive customers.[4]

A prohibition on gas sales by LDCs to other than its captive customers means the conventional obligation-to-serve imposed on a regulated utility must be redefined. The new obligation will guarantee noncaptive end-users precisely that for which they are dependent upon the utility: delivery service, no more and no less. The utility would have a public-service burden only to make available that volume of delivery service for which such customers were willing to pay either on a short-term firm or interruptible basis, or on a long-term contractual basis if there were some associated need to construct new facilities.

With assured access to transport capacity having whatever degree of firmness the end-user is willing to purchase, every wholesale gas purchaser and any moderately large end-user of gas connected to the North American pipeline grid have potential access to a huge and open-ended set of competing gas producers, producing facilities, and producing prospects. Plenty of gas will be available in the field for anyone who is willing to pay for it, and except for brief peak-load intervals, as much physical trunkline delivery capacity as the market demands on most systems. With the nearly inevitable development of secondary markets for transport capacity over the next decade, even the exception just cited can be expected to wither away.

This situation offers buyers the opportunity to shop among producers and other sellers as well as among pipelines and distribution companies for that changing combination of supplies and transport arrangements that optimizes the mix of supply cost and firmness of service. It also offers producers the opportunity to seek that combination of wellhead or downstream sales and transportation arrangements that optimizes their own mix of production requirements and net revenues. Such shopping can be direct (as when end-users deal directly with gas producers and transportation companies) or it can be indirect as when end-users or producers rely upon middlemen-- brokers or marketers--to aggregate or disaggregate supplies or loads and "rebundle"

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[4] For an excellent assessment of the risks of making ambiguous the LDC's obligation to serve its noncaptive customers, see Daniel Duann, Robert Burns and Peter Nagler, *Direct Gas Purchases By Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute December 1989), especially pages 22-23.

sales with transport, storage, or auxiliary services.[5]

Thus, there is no need to shelter noncaptive customers from the commodity market that is readily accessible to them once they have access to unbundled delivery service. Regulation of commodity prices or other terms of sale associated with those supplies cannot promise purchasers any expectation of lower costs or more reliable supply than they are offered by the intense competition among the thousands of suppliers, marketers, and brokers that seek their business.

Only for a shrinking fraction of the end-user gas market--captive residential and small commercial customers--can a plausible case be made that durable market power exists at the local distribution level. It is questionable even there. The speed with which third-party gas-acquisition services have penetrated this sector took industry analysts by surprise and, indeed, remains almost unknown to utilities and state regulators who have not directly experienced these developments.

In the Midwest it took less than two years after the distribution systems were opened to carriage for large industrial gas users before small commercial customers began aggregating their loads and buying gas from independent marketers. Similarly, on the west coast, local school systems began buying gas directly and had those purchases subdivided and delivered to individual schools and administrative facilities. In the Northeast, end-user cooperatives including residential customers among their members were formed in order to meet minimum-load eligibility requirements for transport services. One gas-brokering firm that now operates nationwide got its start in the industry by putting gas purchase and transportation deals together on behalf of low-income residential consumers.[6] And as of 1991, gas utility executives in the province of Ontario reported that fully 26 percent of deliveries to "essential-service" customers was gas sold

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[5] In usual gas-industry parlance, "brokers" facilitate transactions as *agents* of producers or end-users (or other buyers and sellers), without taking title to the commodity or becoming a shipper of record. "Marketers" in contrast are *resellers* of gas, taking title to the commodity at some point and typically shipping it in their own names.

[6] Citizens Energy Corp., a Massachusetts-based, nonprofit corporation came into existence in 1979 to resell fuel oil purchased in bulk shipments to low-income consumers. With the advent of gas-carriage programs in the mid-1980s, it subsequently formed Citizens Resources which took advantage of direct-purchase gas supplies that it had delivered by LDCs to low-income retail customers.

directly to the customer by third parties.[7]

Whatever residual market power exists over gas sales at the retail level owes its survival to the utility's control of essential facilities used to deliver the gas. It is nevertheless questionable whether a right of direct access for residential consumers to unbundled transportation is indispensable if they are to benefit from the existence of competitive gas markets. Many, if not most states have limited the availability of stand-alone delivery service to customers meeting a minimum load threshold, while others require no such minimum.[8] Either way, captive customers can be provided a viable and readily observable benchmark against which they can gauge the success (or lack thereof) of their utility's gas procurement efforts. That benchmark is the cost of third-party gas available to customers of the LDC who can and do avail themselves of unbundled transport service, or rebundled service provided by a nonutility marketer. (This theme is developed further in a later discussion of the uses of spot markets for natural gas.)

Two objections have typically infused resistance on the part of LDCs and skepticism on the part of regulators to proposals that the LDCs be totally relieved of any obligation to acquire gas for noncaptive customers. The first objection is the proposition that, by pooling its seasonally uneven residential and commercial loads with the steadier (or interruptible) nonheating loads associated with noncaptive customers, an LDC can offer producers or marketers a steadier year-round take, and in return obtain a lower average year-round price.[9]

Producers indeed can be expected to accept a lower average price for a level supply to serve a diversified load than for a seasonally fluctuating supply dominated by demand from weather-sensitive customers. This is typically because takes that decline gradually with a producing property's efficient-production profile, and without deep seasonal fluctuations, maximize the present value of the property's life-cycle sales revenues. This principle does not

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[7] See *Natural Gas Supply Security*, a brief presented to the Ontario Ministry of Energy by Centra Gas Ontario, Consumers Gas, Ltd. and Union Gas, Ltd. (August 1991).

[8] See Robert Burns, Daniel Duann and Peter Nagler, *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, Ohio: The National Regulatory Research Institute, January 1989).

[9] For a somewhat cynical appraisal of the "pooling" approach, see Richard Hare and Vincent Esposito, "LDC Rate Design and Transportation," *Public Utilities Fortnightly*, April 1, 1992.

require the utility to purchase gas for its own resale on a levelized schedule, however; only that producers have an opportunity to market the potential off-peak production not taken by the utility.

Otherwise, the ability to achieve a lower average cost for pooled supply is only an arithmetical truism: The market value of gas is highest in periods of peak demand precisely because that is when residential and small commercial loads are greatest. To suppose that captive weather-sensitive customers will benefit from the lower *annual average* cost of pooled supply for their seasonally concentrated loads requires the assumption that noncaptive customers can also be charged that annual average cost. Because such a price is higher than what noncaptive gas users could have obtained on their own for gas purchased off-peak or on a level schedule directly from producers or nonutility resellers, there is no reason for them to cooperate voluntarily in such a subsidy to the utility's captive customers.

The second common objection to relieving LDCs from the obligation to procure gas for noncaptive loads relates to "transition costs" that stem from contractual gas purchase commitments previously incurred to supply noncaptive customers. Perpetuating the LDC's obligation to customers that have no corresponding obligation to be served, however, threatens the incurrence of new costs for which there may be no readily available ratepayer source of funds other than captive customers. That is, in fact, what happens when noncaptive customers refuse the LDC's system supply either because it is more costly than other gas supplies or alternate fuels or because the noncaptive customers' energy requirements simply diminish or disappear. Thus, imposing an obligation to serve such customers out of the LDC's system supply is antithetical to the desire that captive customers benefit from having their supply requirements pooled with those of the noncaptive customers.

The conclusion, however painful, is nevertheless apparent: regulatory attempts to combine a utility's gas purchases into a supply "pool" for low-load-factor and high-load-factor customer categories is unlikely to lower fuel costs for either group. Indeed, such efforts will predictably lead to higher costs for precisely those customers that regulators intended be shielded from excessive costs for peak-period gas supplies.

6. UNDERSTANDING THE SIGNIFICANCE OF THE SPOT MARKET

In hindsight, the growth of spot markets and their influence in meeting customers' natural gas requirements were logical and predictable corollaries of the structural changes initiated by the NGPA. The importance of this development has been overwhelmingly positive, and permits a radical simplification of the reasonableness and prudence standards affecting LDCs. To comprehend the emerging role of spot markets, however, it is useful to review the regulatory treatment of purchased-gas costs in the "old" natural gas industry, vestiges of which remain entrenched in current regulatory practice.[10]

Throughout the era when strict wellhead-price controls were applied by the FPC and its successor agency the FERC, consumer gas prices were inflexible, if not actually "stable", by virtue of the straight pass through of gas-purchase costs. This automatic pass through was uncontroversial, owing in no small way to the below-market ceiling prices enforced by the Commission. When curtailments began during the 1970s, gas prices were substantially below their market-clearing value (this feature, of course, was what caused the curtailments), but even those regulated prices had begun to climb substantially.

Regulators correctly perceived that the necessary rapid escalation in gas prices and the threat of continued price volatility exposed utilities to unavoidable underrecovery of their costs as long as total rates could not be adjusted quickly under traditional procedures. In reaction, both the FPC and state regulatory bodies initiated automatic fuel-cost adjustment procedures--the federal variation of which is known as the purchased-gas-adjustment (PGA) mechanism. In principle, the first-sale purchaser paid its suppliers the regulated prices of whatever categories of gas it managed to acquire, and in turn, the regulators allowed it to bill its customers for whatever was the rolled-in average cost of purchased gas during the accounting period. Pipelines under federal jurisdiction were permitted to project their anticipated average gas costs for future six-month periods, but could "bank," or accrue for later distribution or collection any over- or

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[10] For an extensive analysis of current practices at both the state and federal level, see Robert Burns, Mark Eifert and Peter Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, November 1991).

underrecoveries of actual purchased gas costs. Moreover, "out of cycle" PGAs permitted some pipelines to change their rates for gas supplies more frequently than every six months. The gas cost components of retail customer bills were typically adjusted monthly (with thirty day or more lags depending on the state exercising jurisdiction), to reflect the changes in pipeline supplier gas costs previously approved by the FPC (or FERC).

This automatic pass through mechanism meant that the gas merchant, whether a wholesale or retail utility, was absolved of any objective economic standard of performance with respect to system gas supply costs. The new gas supplies put under long-term inflexible contracts at prices that were multiples of the then prevailing average price were justified to regulators as necessary in order "to assure future supplies." In general, the only material standards of procurement behavior were those that proscribed outright misconduct--"fraud and abuse" in the parlance of the NGPA.

This permissive stance toward the cost of purchased gas made sense, but only to the extent that (1) wellhead price regulation continued, (2) the pessimistic assumptions about the physical scarcity of domestic natural gas proved accurate, and (3) the costs of competing forms of energy continued to escalate sufficiently that gas remained a bargain fuel for those permitted to buy it. Not surprisingly, because these three conditions were inconsistent with the realities of the 1980s, the results were a financial disaster to the pipeline sector.

It is obvious in the 1990s that the business of buying and selling gas is quite different from that of transporting or distributing it. Some industry participants and regulators have yet to draw the necessary inference, however, that the gas procurement practices and performance standards that were appropriate prior to the advent of spot markets and open-access transportation are no longer compatible with the preferences of consumers, the commercial realities faced by natural gas producers, or the redefined economic responsibilities of natural gas pipelines and the LDCs.

A dozen years ago more than nine-tenths of the gas used in North America was sold in the field to regulated transmission or distribution companies for resale at regulated rates. Today, more than nine-tenths is never owned by the company that first transports it, and upwards of two-thirds of all first sales are now "spot" transactions in fact or in effect--sales of thirty days or less, or sales under longer-term contracts with mutual escape ("market-out") clauses and/or prices indexed to spot values or subject to redetermination at thirty-day or more frequent intervals.

Spot markets have been able to achieve their extraordinary dominance in natural gas commerce because of the inherent "fungibility" of methane. One unit of natural gas is indistinguishable from and interchangeable with any other, and infinitely divisible or combinable. Spot prices at various basing points ("market centers" or "hubs") along the pipeline network, moreover, are tightly articulated with one another.

Under these circumstances, buyers and sellers can monitor the balance between supply and demand daily, hourly, or continuously in each market center in pursuit of an ever changing set of market-clearing prices. Those prices confront each seller as the highest value at which whatever volume it tenders can be sold; and similarly, they confront each buyer as the lowest value at which whatever volume it seeks can be purchased.

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7. THE SPOT PRICE AND THE COMMODITY VALUE OF NATURAL GAS

Despite the growth in and overwhelming importance of the natural gas spot market, it is still viewed with suspicion among numerous elements of the industry. It is also misunderstood by many of these same parties.[1] Contrary to the position put forward by producers and their representatives, for instance, it is fallacious to maintain that prices observed for natural gas in today's spot market are representative of only instantaneous supply/demand balances and are therefore separable from expectations for future prices reflective of replacement costs or other influences on the long-term price trend. To the contrary, prices in spot transactions are the most accurate indicator of the consensus of views that prevails at any particular time between producers and gas users regarding the value of gas at that point in time *and in the future*.

By their several but collective willingness to purchase a specific volume of gas at the moment's spot price, buyers are expressing their true opinions regarding its value in current uses. But producers, by their several but collective willingness to sell the same volume at the current spot price, are also expressing their true opinions as to the present value of future revenues they have to sacrifice by selling now instead of holding back production of those volumes or putting them in storage for later sales.

As an example, suppose we expect that demand will grow over time relative to supply. Spot-market prices (which respond instantaneously to the changing supply-demand balance) will have to rise by an amount that balances the anticipated increase in demand with the anticipated supply.

To the extent that market participants expect demand increases to cause *future* price rises, *current* spot prices will rise to reflect the impact of that expectation on the producers' opportunity cost of current sales--for example, the present value of gas that would otherwise be held for future sale. Any long-term agreement incorporating a premium above those higher spot prices, either today or in the future, is thus redundant and unnecessary to the extent it is intended to incorporate these assumptions about the future.

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[1] See for instance, comments filed by Enron Gas Services at the California Public Utilities Commission following an *En Banc Informational Hearing On Natural Gas Procurement and Contract Strategies*, San Francisco, February 5, 1992.

The feedback between current values reflected in short-term market-clearing prices and expectations regarding future values is continuous and unremitting. Given the systematic linkage between expectations regarding future prices and the current spot price, term sales can be evaluated as options on a chain of future spot commodity sales within a single market, as opposed to manifestations of separate markets.[2]

The remarkable fluidity and efficiency of the spot markets are manifested in the fact that these markets clear, year in and year out, despite a swing in heat-sensitive loads--the largest and least price-elastic component of demand -- by a factor of four to one, and despite the fact that clearing the market has required monthly prices to swing as much as 60 percent in the course of a six-month period. Over the last four years, the spot market in the aggregate has offered sellers higher load factors and greater security of sales revenues, and buyers greater security of supply, than either party has historically experienced under traditional term contracts.[3]

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[2] The term "spot market" as used in the natural-gas industry is nowhere defined with great precision, but generally refers to transactions at a single volumetric price fixed for thirty days or less; "short-term" usually refers to transactions (or prices) of more than thirty days but less than one-year's duration; and long-term transactions are generally those one year or longer.

[3] The hope that long-term contracts as such provide either absolute security of supply (or demand), or substantially greater security than other kinds of transactions, has been a frequent source of disappointment in the natural-gas industry. In the 1970s, pipelines saw producers fail to deliver contracted quantities on a large scale, at which time pipelines were forced to curtail deliveries to their LDC customers, who in turn were forced to curtail retail sales to "firm" as well as "interruptible" retail customers. Factories and schools in the Midwest were forced to close as a consequence, and some of the resulting lawsuits took more than a decade to resolve.

In the 1980s, the flip side of the supply-security coin turned up. Producers with long-term contracts negotiated in the 1979-1983 period, believing that security of cash flow was assured through the must-take and take-or-pay terms of such contracts, came to understand that, contracts notwithstanding, purchasers were capable of avoiding or reneging on burdensome purchase obligations, in effect, saying, "I won't take, and I can't pay, so sue me."

Perhaps the ultimate demonstration of the security of supply afforded by long-term contracts was observed in December 1989, when an Arctic cold front swept across North America to the Gulf Coast, causing a record upsurge in demand throughout the Eastern two-thirds of the United States. The low temperatures crippled gas wells, processing plants, and compressor stations in the Southwest, and shut down offshore producing platforms in the Gulf of

(continued...)

In retrospect, perhaps, the reasons for the occasional miserable experience with long-term contracts are obvious--at least they should be to those willing to shake off a conventional wisdom that was nearly fifty years in the making. That wisdom preached that long-term contracts with fixed prices (prices indexed to general inflation or a rate of escalation in excess of general inflation, or to the price of oil, or to a basket of alternate fuels) was a reasonable and prudent way of buying security of supply.

In reality, such contracts were simply gambles that the future value of natural gas would turn out to make the contract's price terms look good, or at least acceptable. To the extent that buyers believed they were capable of forecasting future values accurately, we can only wonder where they found such misplaced confidence. And to the extent that buyers were gambling that their forecasts were going to turn out right, we ought to take note that they were not gambling with their own money--it was ratepayers' money the buyers believed was being committed when they signed the contracts.

In any event, for more than a decade--year in and year out--buyers have been losing their gambles. The greater irony is that many of the "winners" in these gambles--the producers that enticed buyers into the long-term contracts--have turned out to be losers as well. The losing bettors (buyers under long-term contracts) were frequently unwilling or unable to liquidate their gambling debts and took many producers into bankruptcy as a consequence. Thus, the promise of "security of supply" that supposedly justified long-term contracts with onerous price concessions

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[3](...continued)
Mexico. Wells located on Federal offshore tracts, by virtue of Federal law, were produced only under long-term sales contracts. When they became physically incapable of producing gas during a period in which supply security was exceptionally valuable, it was spot transactions that provided substitute supplies. A new "real-time" spot market dealing in daily and hourly transactions emerged spontaneously, as parties with spare gas diverted it to parties offering the highest instantaneous prices.

Thus, in the absence of regulatory impediments, spot markets were able to provide supplies of last resort when other sources and arrangements were exhausted or became dysfunctional. The implications from these two decades of experience are quite contrary to the perceptions of utility executives and regulators: spot transactions can provide customers with adequate supply security and producers with the adequate assurance of demand, if both are willing to accept a market-clearing price and if--as we elaborate later--flexible institutions exist for the allocation or reallocation of transportation capacity.

granted by the buyer turned out to be a phantom promise. Modest reflection reveals why.

When a contract provision requires either a buyer or seller to deliver a commodity at a price that is significantly different from its market value, as reflected in the short-term market-clearing price at the time of delivery, that contract provision has become an economic burden to the party that pays more or receives less than the spot price. Such a party might hope that "things will even out" over the contract term. That is the best ex ante expectation either party can have, however, unless one of them believes it is smarter than the market--that time after time, or alternatively, more times than not, it will "beat" the market price. There are such individuals in our economy who are generally referred to as *speculators*. They play a valuable role in permitting others to shift price risk through hedged transactions in futures markets. Regulated resellers of gas are particularly unsuited players in this game, and long-term contracts with fixed or formula prices decoupled from current market values are decidedly poor instruments with which to speculate on the price of gas, at least in the absence of an active secondary market in which those contracts can be sold or assigned before their expiration.

Such long-term contract gas supply strategies are coming under severe scrutiny as regulatory commissions wrestle with "least-cost," "best-cost," or "optimal-cost" standards for utility procurement practices. In contrast to complex incentive formulas or rigorous prudence reviews, however, the benchmark for procurement behavior appropriate to the competitive environment for gas supply allows unambiguous standards and simple definitions. The availability of a broad and robust spot market for gas is the key to this development. For example:

> *A PUC can establish the allowable unit cost for gas acquired on behalf of captive customers by calculating a sales-weighted average cost of spot-market supplies readily available to (although not necessarily purchased by) the distribution company. Any portion of gas-purchase costs that are in excess of the spot-market average price will be recoverable in rates for service to the captive customer class only to the extent that the LDC pays (i.e., absorbs) a share of that excess--in effect, a split of the excess costs between the utility's stockholders and its captive ratepayers.*

Conversely, any gas-purchase savings relative to the average spot market price would result in credits to captive customers' bills in a pre-determined share with the remainder retained by the utility (again, a sharing, but not necessarily a symmetrical sharing, between the utility's owners and ratepayers). Any investment in field storage or payment of storage-service costs made by the LDC to arbitrage the difference in spot prices in (say) peak- and off-peak periods will likewise result in a sharing by pre-determined formula of costs and benefits that result.[4]

The determination of the appropriate sharing formula is the responsibility of the commission, and there are circumstances in which the formulae might justifiably vary among utilities subject to a commission's jurisdiction. For instance, a utility that has invested in production-area storage facilities, the costs of which are included in its rate base, presumably has made these investments in order to lower the overall costs of its gas supply. (Such storage facilities accomplish this by permitting the utility to purchase

[4] Rudimentary efforts to implement some of the features of this procurement standard have recently been proposed to the California Public Utilities Commission by the Commission's Division of Ratepayer Advocates (DRA) in relation to the gas procurement activities of San Diego Gas & Electric Company (SDG&E). Specifically, the DRA recommended that SDG&E retain 10 percent of the estimated savings that ratepayers experienced as consequence of the utility having purchased its system gas at less than the spot price observed during the annual period in which the energy-cost-adjustment clause operated.

gas in low-cost, off-peak periods, to be withdrawn from storage during peak periods when purchase costs for field production are substantially higher.[5])

But ratepayers are charged directly for the utility's price-arbitrage activity through payments they make that provide a return on the utility's rate base that includes the investment in storage facilities. Thus, the share retained by the utility of fuel-cost savings relative to the spot-price benchmark ought to be substantially smaller than for a utility that made no such investment. Conversely, in those circumstances when the utility with the storage investment exceeds the benchmark cost of gas, the ratepayers' share of those excess costs ought to be very small, because they have provided the utility with a return on its storage investment that was supposed to insure that the spot-price of gas was never exceeded.

The computation of the applicable benchmark spot-market gas costs may require special considerations depending on the location and circumstances of the LDC. In effect, the benchmark should represent what a buyer standing behind the LDC could expect to pay in an arm's-length transaction for gas supplied in a workably competitive market. The physical location of the gas at the relevant transaction point is the LDC's city gate. For only a handful of LDCs in the United States, however, is there a robust commodity market in which spot transactions take place at the city gate and for which representative price data are thus available.

For other LDCs, an upstream spot price will have to be adjusted to "bring it downstream" to the city gate.[6] The observation point for such upstream prices can be any of the major market hubs to which the LDC's pipeline suppliers are connected (for example, Henry Hub, Louisiana; Katy or West Waha, Texas). Transport costs will need to be added to the spot prices for these "hub-markets." Since pro forma transportation costs are determined according to filed rates,

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[5] For a comprehensive examination of natural-gas storage as it relates to gas supply management strategies for LDCs, see Daniel J. Duann, Peter A. Nagler, Mohammad Harunuzzaman and G. Iyyuni, *Gas Storage: Strategy, Regulation, and Some Competitive Implications* (Columbus, OH: The National Regulatory Research Institute, 1990).

[6] One analyst has argued that such adjustments are sufficiently complicated that PUCs ought to strive to avoid them. See Rodney Lemon, "PUC Review of LDC Gas Purchasing Practices and Transportation Agreements;" paper presented at a conference of the National Association of Regulatory Utility Commissioners and the U.S. Department of Energy, *State Regulation and the Market Potential for Natural Gas: Challenges and Opportunities*, Phoenix, Arizona, February 3, 1992.

objective and verifiable estimates can be figured easily. To the extent that the LDC can achieve a lower cost at its city gate through innovative exchange, backhaul, or discounted transport arrangements, the incentives created under the sharing policy proposed here rewards and thus promotes such efficient behavior by the utility.

8. THE IMPORTANCE OF AN UNREGULATED SECONDARY MARKET FOR REGULATED UTILITY SERVICES

In the following discussion, the importance of a secondary market is limited to regulated utility services. The reason we do not deal here with unregulated services, such as wellhead-gas sales, is that no discussion is necessary; secondary markets for unregulated services are accepted without suspicion, without controversy, and without comment. Secondary markets, quite simply, are recognized as efficient means for allowing willing parties to reallocate resources subsequent to their initial allocation or sale. Indeed, so accepted are such exchanges that the term "secondary market" is alien and irrelevant to the concept of reallocating ownership or rights to service -- there is no reason to distinguish the secondary market--there is only *the* market.

The resale status of regulated commodities such as natural gas delivery services[7] are a different matter. As a general proposition, the resale to the highest bidder of transport services purchased from a regulated entity violates the regulations imposed by the FERC and every state regulatory body with which we are familiar. This prohibition continues despite explicit recognition by the FERC that serious market inefficiencies result from its proscription of unregulated resales, assignments, and brokering rights attendant on the purchase of regulated transportation services.[8]

In its considerations on this matter, the FERC has failed to delineate all of the problems associated with the proscription on resale of gas delivery services (including those services rendered by LDCs); economists, however, can readily identify the

[7] As used here, the term "delivery services" incorporates a broad class of service components including conventional storage, balancing, backhaul and exchange services. Perhaps, the easiest way to envision what encompasses "delivery service" is to consider it as including everything other than the commodity itself.

[8] See FERC Notice of Proposed Rulemaking, "Brokering of Interstate Natural Gas Pipeline Capacity," Docket No RM88-13-000.

following inefficiencies wherever secondary markets are prevented from discovering market-clearing prices for delivery services:

* unnecessary shortages of "firm" and peak-period delivery service will occur;
* delivery service will not be allocated to its highest-valued uses;
* interruptible and off-peak services will be underutilized;
* price discrimination at the expense of the most price-inelastic, most captive consumers will be both fostered and safeguarded.

One wonders what regulatory objectives could justify these eventualities. The only economic rationale offered by the FERC has been a fear that permitting a secondary market to operate without strict regulatory oversight might allow rights to delivery service to fall into the hands of monopoly resellers. The restrictions that the FERC has contemplated placing on resellers to counter this potential monopolistic exploitation of secondary markets include certificating every reseller, capping the price at which every sale could take place, and prescribing precisely the specific characteristics of the services in which a "qualified" reseller would be permitted to traffic. For those few state jurisdictions in which creation of a secondary market or the right to resell or broker delivery service has been considered, similar types of constraints have also been proposed.

This is a disappointing reaction in light of the efficiency benefits to be achieved through creation of a private secondary market in the regulated services provided by LDCs. Moreover the remedy for the perceived problem where it actually exists is simple, direct, and speedily implemented.

> *Any reseller found to have all, or even an unacceptably large proportion of rights to service within a submarket under its exclusive control would be required to divest itself of whatever portion of the rights the PUC determined was appropriate. This remedy should apply without regard to intent of the monopoly reseller in acquiring its share of service rights within that submarket.*

The efficiency benefits associated with an unregulated private secondary market are worth enumerating. First, such a secondary market would coexist with and complement the existing primary-allocation mechanisms and regulated cost-based rates applicable to gas delivery services. Thus, conventional public utility rates would continue to prevent distribution companies from exploiting their monopoly franchise control of essential transport facilities to capture monopoly rents. At the same time, however, monopoly power is likely to be absent in the resale market because the addition of incremental sellers of the LDC's services, by definition, results in the deconcentration of control over salable delivery capacity. This would mean that the difference, either positive or negative, between regulated cost-based LDC charges and competitive value-of-service resale rates would reflect legitimate and economically useful scarcity rents (as opposed to ill-gotten monopoly rents). Moreover, gains and losses from resale of capacity rights in the secondary market would function to allocate scarce resources (peak-period capacity or bottleneck segments) to their highest-valued uses, as well as to maximize utilization of off-peak and overbuilt distribution segments.

It is important to emphasize that all transactions in the secondary market are voluntary. No assignment of delivery rights takes place unless both parties to the transaction benefit. Specifically, no party that paid for delivery-service rights at less than their market value under established regulatory mechanisms would be forced to surrender them. Moreover, even these parties that abstained from using the secondary market would nevertheless receive correct price signals since the *opportunity costs* of holding unused rights to service will be apparent in the income foregone by not assigning or reselling unneeded or less-than-optimally employed rights in the secondary market.

There are additional advantages and benefits to an unregulated secondary market for utility services. For instance, utility customers left to their own devices will have incentives to subdivide, recombine, or otherwise restructure the rights to service for which they have paid but which they wish to temporarily or permanently divest. The incentive for these actions will be the desire to maximize the value of any new bundle of goods such customers seek to market in competition with the utility's service offerings. Because these "competitors" are free to experiment in partitioning and consolidating the property rights being exchanged, commission staffs need only observe the results of the bundling and unbundling procedures which the secondary market reveals are appropriate. Those "commodity bundles" that survive this market test should provide the focus for commissions in their efforts to compute costs, initial rates, and access conditions for services that the marketplace has sanctioned as relevant.

Another implication is that while capacity allocation and ratemaking mechanisms will differ between the primary allocation and secondary market, a powerful feedback link from the second will contribute to greater efficiency in the first. This will improve the efficiency of the former. For instance, where service is truly scarce, prices established in the secondary market will exceed utility rates, thus signaling to the utility company that investment in additional capacity is economically warranted because of the observable scarcity rents flowing to the resellers. On the other hand, where primary purchasers of service rights are unable to utilize all the capacity they have reserved and are unable to recoup their payments to the utility in the secondary market, they will tend to seek reduced reservation levels, depending themselves on purchases they can make from other resellers. These actions will, in turn, signal the utility to reduce its rates.

Services offered in the secondary market will move to where they command the highest value; those who hoard rights to services in the hopes of driving the price up will be undercut by others willing to accept that rate. Unlike the spot market for gas, however, the would-be monopolist attempting to corner the secondary market for utility services has to confront the ultimate competitor--the utility from which it initially bought its rights to service. Any attempt to charge a price greater than the competitive price is doomed as long as the utility is capable of making interruptible service available (and this is always the case whenever the reseller hoards its rights to service in order to drive up the secondary market price)--the would-be monopolist will lose its market to the utility's regulated services. Moreover, such a reseller is subject to the mandatory divestiture rule described previously, and necessarily loses revenues it might have earned otherwise.

The same attributes that permit the spot market to serve as the supply of last resort--it is always there if you are willing to the pay the market price--are exactly what will allow a private secondary market to function as the clearing mechanism capable of finding the true market price for delivery services at any instant.

The benefits of the secondary market merit summarizing. Its existence does not replace the regulated market for the utility services which it augments, but merely adds a means of making more flexible adjustments to changing market conditions and changing customer preferences than regulatory procedures permit. A secondary market creates alternatives to the choices that utility suppliers are able to offer. The availability of a secondary market makes straight fixed-variable rates a more acceptable rate design because it allows customers to shed part of the risk they otherwise are required to bear in its entirety if resales of services for which they have no immediate need are prohibited.

Finally we should comment on the policies implemented in FERC's Order No. 636 intended to control the ability of utility customers to buy and resell services that are initially allocated under a regulated tariff. The procedure requires that any *customer* of a pipeline who desires to assign or sell firm transportation capacity rights it has purchased under a filed tariff must first accept a certificate from the FERC, thereby becoming a regulated entity subject to its jurisdiction. This customer then must describe the terms (including any minimum acceptable price) under which it will release to the pipeline its available transportation space so that this information can be posted on an electronic bulletin board the FERC requires the pipeline to maintain.

The most immediate consequence of this policy, assuming the FERC's attempt to regulate pipeline customers can be legally sustained, is to extend federal jurisdiction to thousands of heretofore unregulated entities including producers, independent marketers and brokers, industrial gas users, nonutility electric generators, and so on. Of course, LDCs will be subjected to both state and federal regulation. A second major effect of the FERC policy is that control over matching willing buyers and sellers will be placed in the hands of the pipelines from which the services are purchased originally. Thus, instead of allowing the utility's customers to compete openly with one another as well as with the utility's service offerings, the FERC would have the utility compete with itself by "brokering" those transport rights purchased by its customers and released back to the utility.

Earlier, we pointed out that the frustrations with constraints on the resale and assignment of transportation rights were diffused and indeed lessened because of the existence of a "gray market" in capacity rights. By "gray market" we mean a set of transactions that are structured out of permissible elements in order to accomplish something that would otherwise be prohibited or discouraged.

The most common gray-market transaction that accomplishes the resale of transport capacity between a willing buyer and a willing seller is known appropriately enough as a "buy-sell" agreement. Not only have such transfers taken place throughout North America, but these exchanges frequently occur at "virtual" or "shadow" prices (for example, in this case the implicit transportation component of the downstream gas price) that exceed by a substantial margin the pipeline carrier's maximum lawful rate for transport service.

The gray market got its start in the United States in the mid-1980s, when the FERC established rules under which rights to firm transportation were attached to specific supplies of natural gas. Specifically, a number of pipeline-producer settlements of disputed gas supply contracts contained firm transportation privileges (often at discounts from the pipeline's filed transport rates).

Similarly, supply contract renegotiations authorized under FERC's Order No. 451 incorporated new contract terms providing transportation privileges for gas released as a consequence of those renegotiations.

The effect of these transport rights bundled with specific gas supplies was that the position of potential shippers in the first-come, first-served queue for transport access was not necessarily the final arbiter of who was permitted to have gas shipped on a firm basis. In effect, a shipper without standing in the queue was still capable of securing transportation service on a firm basis, if it was willing to purchase gas from a "privileged" source in order to get that access. Technically, the shipper was the producer whose gas had the attached transport privilege. In reality, however, it was the transport right which was negotiable, and it commanded a value in the market that had no connection with the filed rate or with the discounted charges contained in the renegotiated contract.

These arrangements continue today. Indeed, in Canada the National Energy Board encourages them as did some states in the United States in a roundabout attempt to encourage load retention and greater throughput on LDCs' systems. Such transactions are more common because one need not always find a transportation-privileged gas supply. One can bring one's own gas to the entity (typically an LDC or a pipeline marketing affiliate) that has transport rights and engage in a "buy-sell" agreement with that party. Such an arrangement entails the transportation-privileged shipper buying the gas from the ultimate customer at the intake point on the transporting pipeline and then reselling that gas back to the customer at its delivery point. The price for the delivered gas is adjusted to whatever level is necessary to capture the scarcity rent attributable to the transport service. The purpose of the sale is to give the proper form to an otherwise illicit exchange of transportation rights.

While these gray-market transactions contribute to greater allocative efficiency in comparison with a system that would prevent all reallocations of either bundled or unbundled transportation service, they nevertheless have serious shortcomings. The gas prices that are reported to the trade press for the buy-sell arrangement, while unlikely to distort seriously an objective measure of the then-current market value of gas, do deprive the public of accurate price signals appropriate to the transportation service.

In counterbalance to the artificially inflated gas price, the transportation fees reported in these gray-market transactions are necessarily artificially depressed. This sort of misinformation means that pipeline and distribution companies have misleading measures of where and to what extent bottlenecks exist that warrant mitigation. In addition, there are likely modest transaction-cost penalties owing to the added burden of having to arrange and document the purely extraneous sale and repurchase of the gas.

From the standpoint of effective state regulation, the most unwelcome feature of the artificial gas-sale transactions is that the regulators have no basis for holding LDCs accountable for the firm transportation rights they have reserved and for which they temporarily (or permanently) have no need. The opportunity for LDCs to operate in a legal and unregulated secondary market encompassing all delivery services--either buying or selling such rights--means that state regulators could establish legitimate performance criteria affecting the amount of contract demand or capacity reservation rights it is prudent for an LDC to retain.

Absent the options of assigning, reselling, or purchasing transport rights that the secondary market allows, LDCs have always been in the uncomfortable position of contracting for pipeline service based on the possibility of an extreme peak-day requirement, and then sitting passively with those capacity rights which are substantially in excess of their normal-year requirements. This has meant that the LDCs incur substantial demand and reservation charges for capacity which, most of the time, is extraneous to their customers' requirements.[9]

Commissions have had little recourse in judging the appropriate level of reserved transport capacity or contract-demand quantities, the costs for which the LDCs have obligated their retail customers, because of the hazards involved in second guessing the LDC's peak-demand projections. A benefit the secondary market provides in this regard is as a forum in which capacity that is temporarily surplus can be released to a willing purchaser and in which, conversely, a temporary shortage of capacity can be cleared at the current free-market price. This competitive market discipline offers commissions a rare opportunity to establish simple standards for acceptable utility performance. The following rule is suggestive of the type of standard that commissions could apply to the LDCs they regulate:

> *The allowable recovery of demand charges paid to pipeline companies for transmission services is defined by the actual usage of transmission service for which the LDC avails itself. Any excess reserved capacity, for which the LDC paid pipeline-demand charges, can be sold in the secondary market and the LDC's recovery of those demand charges will be dependent on and limited to such secondary-market sales. Thus, the revenues received in that market will be retained by the LDC so long as it is at risk for all costs of any reserved transmission space that is not utilized on behalf of its firm retail customers.*

[9] This cost exposure will only increase as straight fixed-variable rates are implemented in accordance with the requirements of FERC's Order No. 636.

> *Conversely, any purchases of incremental delivery service in the secondary market that are required to meet firm customers' load requirements, the capacity for which was not reserved by the LDC, will be recoverable in the rates charged firm customers. This symmetric treatment of cost exposure is justified because firm customers avoided the reservation charges that would otherwise have been necessary to secure the capacity purchased in the secondary market.*

Regulators might consider modifications to this basic approach if there is a presumption that end-users would benefit from assuming part of the risk of excess- capacity rights retained under a tariff agreement rather than relying on the secondary market to acquire such capacity when it is needed. In this case, the regulator could establish some maximum reserve margin, say 10 percent, above actual peak demand, and allow recovery of demand charges associated with that reserve in the rates charged firm-retail customers. Sale in the secondary market of whatever portion of the 10 percent reserve is temporarily unneeded must then be credited to the firm customers' revenue requirement either on a projected volume/revenue basis or on the basis of a retroactive adjustment.

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9. THE IMPLICATIONS FOR RATE STRUCTURES

We previously discussed the emergence and relative importance of both the noncaptive customer class and the spot market for natural gas. Both phenomena have had implications for the design of rates as well as for the cost basis from which rates are structured. Their most widely recognized implications have resulted from the emergence of noncaptive loads served by LDCs and the federal policies that permitted LDC bypass. Conventional class-cost allocations and the resulting rates will be irrelevant to customers whose stand-alone cost of gas delivery service is less than the regulatory "cost-based" computations.

LDCs need and have been granted discretion over the rates charged certain classes of customers or for certain classes of service; troublesome claims of discriminatory rate treatment almost always arise as a consequence. But there is a ready test, if not an immediate remedy, for such discrimination. Operation of an unregulated secondary market would permit resale of the service that has been rendered at the allegedly discriminatory rate, and the most lucrative resales would be to "victims" of the alleged discrimination. If the reseller can not duplicate the service for the new buyers at a price that earns it a profit, however, the claim of discrimination fails: the services offered by the utility to its customers at different prices are indeed different because, and to the extent that, the cost of providing them is different.

If a reseller can in fact generate profits from such sales, then discriminatory rate treatment is a reality. The discrimination may stem from a preferential (that is, subsidized) rate the LDC charges the potential reseller; it may be that the regulated rate to the victims of discrimination is too high--greater than warranted by the cost of service, or both. In any event, exposure of discriminatory rates so that commissions can consider appropriate remedies can be a significant side-benefit of a free secondary market.

The growing importance of the spot market for natural gas has put added pressure on the role that price signals play in communicating relevant economic information. In particular, rates that are insensitive to climatic and other changes in supply and demand frustrate the price-signaling mechanisms that efficient markets require. To levelize the seasonal cost of service that the consumer sees creates unnecessary inefficiencies and raises the ultimate cost of energy services to all customer groups. These major distortions, of course, stem from undercharging for gas service during the heating season and particularly on peak-demand days, and overcharging at other times. Prices set on the basis of annual cost averages ignore the different scarcity conditions associated with the seasonal pattern of demand. Efficient prices reflect those scarcities, encouraging consumers to ration their demands for service voluntarily according to the value they place on an increment or decrement of service.

Moreover, the desire to accommodate the retail consumer's presumed preference for relatively stable monthly bills has ready solution in the ubiquitous "budget-billing" option. This billing scheme permits consumers to prepay for peak-period energy consumption during the off-peak months so that monthly bills are roughly level. Customers are educated to this process, which is quite compatible with bills that fully disclose the actual costs that accrue in each month.

Even this kind of billing information will be misleading about the underlying marginal cost of gas service at different times, because the vast majority of regulatory commissions including the FERC refuse to implement time-varying rate structures that communicate to customers the relative scarcity of transport and delivery capacity, as well as that of gas supply.[1] There is no reason, however, that such time-sensitive rates can not be implemented together with the budget-billing option in order to accommodate customers' desires for level monthly payments.

The interplay between rate design and other challenges facing state commissions is important. Specifically, consistent and economically efficient rate structures will have to be put in place before any demand-side management programs can be rationally designed and economically justified. Not until the real resource cost of gas service is

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[1] See *Electric and Gas Rates for the Residential, Commercial, and Industrial Sectors; 1990*, 2 vols. (Chicago: Gas Research Institute, May 1990).

accurately reflected in rates can planners, much less consumers, make determinative comparisons between energy consuming and energy conserving investments.

This need for more economically rational retail rate structures has been compounded by the significant changes in rate design for electric utilities during the last decade. Within the electric utility industry the advent of marginal-cost-based pricing, the elimination of incentive and declining block rate schedules and the almost universal adoption of seasonal rates stands in stark contrast to the ratemaking practices that still characterize the gas-utility industry.[2] There are a handful of state regulatory jurisdictions that have, in fact, sought to apply consistent rate design principles in regulating gas and electric utilities, but such efforts are notable as much for their scarcity as for their success.[3] When the same economic principles embraced by commissions in designing rate structures for electric companies are applied to gas utilities, corresponding opportunities will appear to apply similar demand-side management and integrated-resource-planning standards on LDCs.[4]

[2] Despite the progress made in the area of electric utility rate design during the 1970s and 1980s, new deviations from economically optimal rates appeared during the same period. Specifically, there was a tendency to introduce "ad hoc" rates or incentive pricing to accommodate social or other political objectives. For instance, special "promotional," or "load-retention" rates have been crafted for favored customers (e.g., electricity rates for aluminum and titanium smelters indexed to world prices of these metals).

[3] See "Integrating Competition Into Least-Cost Planning," John Chamberlin and Dana Toulson, in *Proceedings: National Conference On Integrated Resource Planning*, (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1991).

[4] For an extensive discussion of both demand-side management policies and regulatory approaches to integrated resource planning, albeit from the perspective of the electric utility industry, see F. Krause and J. Eto, *Least-Cost Utility Planning: A Handbook for Public Utility Commissioners, Volume 2*, (Washington D.C.: National Association of Regulatory Utility Commissioners, December 1988).

10. IMPLICATIONS FOR INNOVATIVE REGULATORY PROGRAMS

Incentive regulation schemes have been surveyed elsewhere.[5] As these studies have pointed out, the traditional approach to utility regulation carries with it its own set of incentives to performance on the part of regulated firms. Thus, the idea that innovations in regulatory approaches that carry stronger incentives to "efficient" and/or more desirable performance require comparative analysis with the status quo and consequent justification in terms of positive net benefits.

We have already proposed a reasonableness test for system gas procurement that is appropriate to the present and anticipated market structure, and identified a benchmark against which LDC performance can be measured, rewarded and penalized. But are there other LDC functions for which existing regulatory practice fosters inefficiency, or for which conventional reasonableness or prudence reviews can not effectively assess or correct?

Using the traditional description of the natural gas industry, the three main sectors are: (1) production and wellhead sales, (2) long-line transmission and aggregation of gas for resale, and (3) "bundled" retail distribution and sale. Each is characterized by different regulatory regimes. During the 1980s, the most impressive gains in efficiency and reductions in cost have occurred in production and wellhead sales, no doubt because deregulation of first-sale prices has permitted this sector to mimic the textbook description "pure competition." There has been palpably less progress in the downstream transmission and distribution sectors.

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[5] See, for instance, Mohammad Harunuzzaman, Kenneth Costello, Daniel Duann and Sung-Bong Cho, *Incentive Regulation for Local Gas Distribution Companies Under Changing Industry Structure* (Columbus, OH: The National Regulatory Research Institute, 1991) and Kenneth Costello and Sung-Bong Cho, *A Review of FERC's Technical Reports on Incentive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1991).

One could argue that this ranking of performance has been predictable. The producing sector has been thoroughly deregulated and freed to respond in every direction to the profit incentives to which it was exposed. Its consequent economic performance has been spectacular, and has resulted in a remarkable fall in wellhead prices. So too with some parts of the wholesale marketing business and parts of the long-line transmission function. But long-line transmission and the aggregation and sale of gas for resale are as yet not fully unbundled and only imperfectly competitive. Pipeline and reseller margins have indeed shrunk, but by a much smaller proportion than producer prices.[6] Even more so, retail distribution has remained centralized, subject to monopoly franchises, and embedded in regulation. Its costs have not declined at anything near the rate that the production segment of the industry has exhibited.

While these contrasts are both generalized and circumstantial, regulators have reason to question the incentive mechanisms that act on LDCs. The plausible answers to these questions, however, in principle occupy the same range as the incentive-regulation mechanisms that have been suggested and extensively analyzed with respect to electric and telecommunications utilities.

Ultimately, complex incentive-regulation strategies are justifiable only for those gas LDC activities appropriately regulated. Moreover, as integrated resource planning (IRP) programs gain popularity, it is important to recognize that their focus is on the complete set of activities necessary to the utility's regulated-production processes together with consumers' conservation and consumption decisions. The benefit to the IRP approach flows precisely from its global perspective on the energy consumption process and the utility's operations. Thus, proponents of IRP should discourage any regulatory incentive scheme that targets specific operations and activities of the utility or isolated performance in some LDC submarket.

Deregulation is the ultimate, and often the simplest economic-incentive mechanism, but it is appropriate only for those functions, such as gas procurement, that are or can be made subject to the discipline of competitive forces. Moreover, it is equally essential that any such deregulated activities be carried out at arms-length from a utility's regulated functions and business entities. Just as competitive bidding for new electrical-generation resources has become an acceptable

[6] See Bruce Henning, "Distribution and Transmission Pricing in the Natural Gas Industry," *Gas Energy Review*, November 1991.

form of "deregulation," but only with proper attention to any affiliate relationship between bidders and purchasing utilities, so too should regulators be wary of opportunities for cross-subsidization and the potential for self-dealing by affiliated entities in the gas distribution business. There is nothing unique to the "new" natural gas industry in this regard; state regulators had to confront the potential for affiliate abuse when they revised regulations to accommodate and encourage the increasingly competitive components of the telephone and electric utility industries. So too, will they have to recognize the potential for the same type of abuses by LDCs.

11. NATURAL GAS-FUELED MOTOR VEHICLES

The comparative economics of compressed natural gas (CNG) motor vehicle fuel indicates a significant new market potential. The stock of gasoline- and diesel-powered vehicles in North America numbers more than 190 million units. Of these, some 13 million are fleet vehicles operated by government and industry.[7] Even more than the lower operating and maintenance expenses for methane-fueled vehicles, environmental considerations are the major impetus for federal and state policies intended to force the transition to "clean" fuels, particularly natural gas.[8]

The technology for using natural gas as a motor fuel is neither esoteric nor prohibitively expensive. Natural gas vehicle (NGV) technology in the United States has been thus far applied mostly in adapting gasoline powered engines to dual-fueled capability. Such conversions require installation of a fuel delivery system capable of being switched from liquid fuel to CNG, addition of high pressure tanks, and a dashboard-mounted switch allowing the operator to shift from one fuel to the other. Despite demonstrated technical feasibility, less than 50,000 motor vehicles in the United States have been made capable of alternating between CNG and a liquid motor fuel.

Dedicated CNG vehicles--for example, those capable of burning only compressed natural gas--have typically been built for local and short-haul fleet applications--taxis, van pools, mass-transit vehicles--and the liquid fuels with which CNG competes in these applications include diesel fuel and propane as well as gasoline. Far fewer dedicated CNG vehicles than dual-fuel installations are operating in the United States.

Dual-fuel conversion costs for light-duty vehicles (passenger cars, light trucks, and vans) as of 1991 were reported to be on the order of $1500 for fleet vehicles and between $2500 and

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[7] See P. Wilkinson, "Natural Gas and Electric Vehicles--An Economic and Environmental Comparison with Gasoline Vehicles," *Gas Energy Review*, June 1991.

[8] See Christopher Weaver, "Natural Gas Vehicle Emissions and the Environment," *Gas Energy Review*, January 1991.

$3500 for individually owned passenger cars.[9] For a dedicated-CNG-powered vehicle the estimated incremental capital cost was reported to be in the vicinity of $1000,[10] and would likely fall to zero or less in the face of interfirm competition for world-scale production-line numbers. The latter vehicle type enjoys lower maintenance costs because combustion of methane results in less wear on internally lubricated engine parts. These savings, like the fuel savings, are necessarily realized over the operating life of the vehicle, while the incremental capital costs are, of course, incurred immediately by the vehicle owner. Thus, the choice between an NGV and a conventionally fueled vehicle requires a present-value calculation of the life-cycle costs of ownership and operation. While the computations are straightforward in principle, their assumptions about future fuel-cost trajectories and availability of fuel-delivery systems are necessarily speculative. In our view, the pricing assumptions incorporated into such assessments have tended to reflect the chronic and unrealistic pessimism of analysts and gas-industry spokesmen about future resource availability and cost.[11]

In addition to this pessimism about the future availability of natural gas, another obstacle to expansion of the CNG fuel market has been the lack of an infrastructure allowing easy refueling by operators of NGVs. Indeed, fleet owners that opted for natural gas typically have had to undertake construction and operation of their own

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[9] See, for instance, S. Salyer, "Fuel Options Rise Day By Smoggy Day" *The Everett Herald*, Everett, WA, Feb. 8, 1992.

[10] See, for instance, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Four: Vehicle and Fuel Distribution Requirements* (Washington, D.C.: U.S. Department of Energy, August 1990), or P. Wilkinson, "Natural Gas and Electric Vehicles--An Economic and Environmental Comparison with Gasoline Vehicles," *Gas Energy Review*, June 1991.

[11] For a review and critique of the pessimistic views and gas-price projections generated by government and industry in the United States and Canada, see Arlon R. Tussing, "Natural Gas: Fuel of the Decade and Bridge to the Millennium," *Energy Exploration & Exploitation*, forthcoming.

refueling facilities. Thus, of the 328 NGV fueling stations operating in the United States in 1991, 205 were maintained for fleet vehicle use exclusively.[12]

During the coming decade, this lack of infrastructure will be decisively overcome, spurred by the Clean Air Act, environmental policies at the state level, and the push by both federal and state government to promote nonoil-fuel capability for energy-security reasons.[13] More than 100 NGV fueling facilities were opened during 1991 in the United States, and seven major gasoline retailers are now actively engaged in marketing gas as a transportation fuel.[14] In California, more than $30 million in capital investments during 1992-1993 has been directed at alternate fuel programs specifically incorporating NGVs.[15]

The challenge to state regulators from these developments relates to regulation of the delivery systems by which natural gas is marketed to vehicle operators. Two extremes in regulatory philosophy present themselves, with a variety of strategies lying between. At one end of the spectrum is the treatment of retail CNG marketers as an extension of the local utility. In at least one instance, a commission has considered limiting entry into the vehicle-fueling business to existing LDCs. The rationale for regulating NGV fuel-marketing as a utility function appears to be bound up with the desire to subsidize this activity now, in order to accelerate the penetration of "clean fuels" in the transport sector. State commissions can manipulate rates to extract this subsidy from existing gas users thereby relieving legislative bodies of the need to appropriate tax

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[12] Mark Bononi, "The Natural Gas Industry and Natural Gas Vehicle Infrastructure," *Gas Energy Review*, April, 1991: 15.

[13] See *Analysis of the Economic and Environmental Effects of Compressed Natural Gas as a Vehicular Fuel, Volume 1*, U.S. Environmental Protection Agency, April 1990, and U.S. Department of Energy, August, 1990.

[14] See *Gas Energy Review*, January 1992; These data speak to the supply side of the equation; the demand side is being addressed by programs to foster the sale of NGVs. For instance, the General Services Administration ordered 600 dedicated-CNG vehicles from General Motors Corp. in 1991 as reported in *Natural Gas Week*, January 20, 1992: 15. Other federal agencies, including the U.S. DOE and EPA, took delivery in 1991 of dedicated CNG vans manufactured by Chrysler Corporation according to *Gas Energy Review*, January 1992.

[15] *Gas Energy Review*, January 1992.

moneys for the purpose. The California Commission has allowed two LDCs to incorporate NGV-fueling facilities into their general rate base, and ordered the LDCs' sales and transport customers to fund the investment in these facilities through a throughput surcharge. The retail price of the natural gas fuel has, in turn, been made subject to regulation by the commission.

This is potentially dangerous territory for reasons that potential competitors of the utilities will be only too ready to point out to regulators. Nonutility competitors will have neither a comparable source of investment capital nor a comparable guarantee of a regulated return on investments in fueling facilities. Gas buyers and transporters who are the source of the payments the LDC uses to fund its NGV fueling facilities, will also have serious grounds for complaint. If the environmental benefits of alternative-fuel vehicles are considered externalities from which society as a whole will gain, then the decision to target gas users for taxation through utility bills is no less invidiously discriminatory by virtue of its opportunistic availability.

In contrast to state regulatory policies that position the LDC as the supplier of first resort for NGV fueling service, all marketers of NGV fuel can be treated just as gasoline retailers are now treated in which case no limits on entry and no price regulation would need to be imposed. As *commercial customers* of the LDC, the issues these fuel-delivery facilities raise with respect to bundling or unbundling of sales, pooling of delivery points, etc., are little different from other commercial customers, (say) fast-food outlets, except that NGV fueling stations are not retail, but rather wholesale customers. Thus, some states (Michigan, Texas and Oklahoma are examples) have seen the marketing of natural gas to NGV operators as a competitive enterprise, requiring safety and environmental regulations of the sort applicable to retailers of gasoline, but an unsuitable subject for conventional utility-type economic controls.

The contrast between these two business strategies may reflect important differences in overall regulatory philosophy. Both philosophies can conceivably coexist, with different, distinctly separate means of fostering the development of the NGV fuel-delivery system. Clearly, the marketplace may evolve a delivery system unlike that which the American Gas Association, or the U.S. Department of Energy, or the American Petroleum Institute, or any of those commissions that choose to regulate it can currently envision.[16] The existence of four dozen or so commissions, coupled with the wide range of state autonomy regarding the regulation of intrastate commerce, may afford a useful opportunity for controlled testing of alternative market strategies.

[16] For contrasting views of the physical structure and cost of the nationwide NGV-fueling system compare, for instance, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, Technical Report Four: Vehicle and Fuel Distribution Requirements*, U.S. Department of Energy, August 1990, with the view presented in Paul Wilkinson, "Natural Gas and Electric Vehicles--an Economic and Environmental Comparison with Gasoline Vehicles," American Gas Association, *Gas Energy Review*, June 1991.

12. SUMMARY AND CONCLUSION

Fundamental changes that have already occurred in the "upstream" sectors of the natural gas industry (production, interstate transmission, and wholesale marketing) are now a driving force and provide a ready model for similar changes in retail gas distribution and in the attendant state regulatory institutions. The influence of these downstream changes converges on the various commissions simultaneously with a cluster of market and regulatory innovations that the commissions first applied to, or considered for, other traditionally regulated industries such as electricity, telecommunications, and freight transportation. Together these developments can be expected to dictate the evolutionary direction of the retail gas-distribution business, and the range of policies and procedures over which state regulators will exercise effective discretion. Together, therefore, they offer a trustworthy preview of the agenda faced by state regulatory agencies in the 1990s.

The most potent sources of upstream change have been the end of federal controls on wellhead prices and the decoupling of natural gas as a commodity from interstate transmission and storage services. Together, these reforms have created a continent-wide network of fluid, efficient and, above all, *clearing* markets for the sale and purchase of natural gas. Short-term market-clearing prices fluctuate dramatically to balance supply and demand in the face of wide seasonal swings in space-heating loads, whereas regional price disparities have narrowed to values that reflect real transport-cost differentials. The larger, essentially arbitrary differentials that were formerly based on contract "vintage" or some legal classification of wells, producers, or end-users have nearly disappeared. The flexibility of prices and other features of free markets have also virtually eliminated the physical supply risks that preoccupied LDC planners and state regulators in the past. Effectiveness and efficiency in gas production and wholesale marketing have steadily improved over the last decade, so much that the inflation-adjusted cost of gas at the city gate is now typically about an order of magnitude (nine-tenths) lower than the industry anticipated ten years ago.

The variety and sophistication of potential procurement strategies have proliferated as

LDCs gained access to free-enterprise commodity markets, unbundled interstate transmission, and contract-storage services. LDCs can now choose between delegating the pooling, supply firming, and load-shaping or load-leveling responsibilities that were formerly concentrated in the pipeline companies to various kinds of parties--mostly unregulated--including producers, pipeline, or LDC sales affiliates and independent marketers, or to undertake these aggregation and coordination functions themselves.

It should be no surprise in these circumstances that important blocs of retail gas customers would entreat the LDCs or, if necessary, the commissions to grant them direct access to the rich variety of choices existing just outside the LDC's city gate, and that such customers would press for the LDC's to afford them the same menus of discrete service elements within their distribution systems--unbundled transport and storage, for example, and a continuum of service "quality" (that is, firmness versus interruptibility--that FERC was requiring the interstate pipelines to offer. It is equally predictable, moreover, that producers and marketers also would clamor for direct access via the LDC's lines to the hitherto "captive" customer base.

The progression of such demands confronting LDCs mimics that experienced by the interstate pipelines, but delayed two, five, or ten years. Unbundled transportation is at first typically restricted to *fuel-switching* industrial customers and *potential bypassers,* and is provided at margin-based rates; the next demands are for wider eligibility for transportation and for *cost-based* rates; followed by open, *nondiscriminatory* access for an ever wider customer base (ultimately including "core" customers); for equal access to *storage and upstream pipeline capacity* hitherto controlled exclusively by the LDC for its system supply; arms-length dealings with utility affiliates; a *secondary market* ("capacity brokering") in transport services; and finally, for greater exposure to market risk for the utilities as an incentive to efficiency.

Virtually the entire body of traditional public utility theory and regulatory dogma conceivably can be marshaled in opposition to one step or another in such a progression. Some LDCs and some regulators will, accordingly, lean resolutely against the current of change. As the natural gas industry as a whole becomes more open, market-driven, and decentralized, however, a growing number and variety of "stakeholder" groups will seek accountability from the LDC and due process from the commission, and with growing effectiveness. On the whole, these groups will be more familiar with unregulated markets and less sympathetic to inherited regulatory concerns and conventions than previous cohorts of Commission intervenors. We are convinced, therefore, that a sequence of demands such as that outlined above will sooner or later prove irresistible to most LDCs and to most commissions.