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Natural Gas Policy and the Midwest Region

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Executive Summary

Energy consumers in the Seventh District, especially residential consumers, depend on natural gas to fulfill many of their energy needs. The five Seventh District states (Illinois, Indiana, Iowa, Michigan, and Wisconsin) use natural gas to meet approximately 28 percent of their overall energy consumption. For this reason, national policy toward natural gas production and delivery remains critical to this region. The natural gas policy decisions of the next few years, including the issue of accelerated gas market decontrol, will affect the economic vitality and direction of industrial, commercial, and residential activity in the Midwest.

In the past, the complex structure of gas market regulations has carried mixed blessings to the District states. Federal price ceilings on the domestic production of gas were able to hold down customer prices for natural gas, but only at the expense of the Midwest supply shortages experienced in the 1970s.

Intermittent shortages in supply moved federal policy toward major revisions of gas market regulation. The Natural Gas Policy Act of 1978 (NGPA) secured greater supplies of natural gas for interstate customers, including Seventh District residents, through favorable allocation directives and higher producer prices.

In addition to a continual easing of wellhead prices for natural gas, the NGPA set a complex schedule of price ceilings over most production from domestic gas wells. NGPA price ceilings on most existing gas categories, especially gas from wells of recent discovery, will be removed on January 1, 1985, covering an estimated 55-65 percent of domestic gas production. Some natural gas wells of older vintage remain under price control indefinitely.

Consequently, the current decontrol timetable gradually frees gas production from price control as the gas from older wells becomes exhausted.

The NGPA price schedule was intended to gradually raise average gas prices to parity with petroleum prices by the time of partial decontrol in 1985. In this manner, decontrol would not subject gas consumers to price shocks. A regulatory middle route was fashioned between the development goal of spurring energy production and the immediate necessity of holding consumer prices at bay.

Despite the intent of the NGPA to restrain consumer price increases, post-NGPA price levels have risen at a much faster rate than had been anticipated. On average, gas prices rose at rates of almost 20 percent per year in recent years, easily outstripping the general rate of price inflation. Most analysts concede that climbing world energy prices, led by the 1979 OPEC round, are mostly responsible for climbing domestic prices of natural gas. Nevertheless, regulatory features of the NGPA, coupled with erroneous market regulation of an earlier era, have accommodated gas price increases by insulating producers and pipelines from declining market demand while gas consumers pay final prices that may lie above market-clearing levels. In addition, the structure of NGPA price ceilings may be deterring exploration and recovery of gas for future consumption, portending future prices for natural gas that are greater than they need to be.

Over the past two years, domestic and world energy demand have fallen due to conservation and world-wide recession. While the petroleum market has responded to sagging demand by lowering prices, wellhead gas prices have continued to rise despite slack demand and excess production capacity. Although falling consumption does create some problems for the production sector, the past and present regulatory structure has protected producers and pipelines from falling consumer prices.

Shortages of interstate gas supplies in the 1970s, caused by pre-NGPA ceilings on interstate gas, induced pipelines to contract for inordinately large deliveries of high-priced gas in today's market under so-called "take-or-pay" contract clauses. Pipelines must pay for these deliveries even though much of this gas cannot be sold to pipeline customers at contracted prices. Since renegotiation or "market out" clauses are absent from many pipeline-producer contracts, pipelines cannot force producers to renegotiate wellhead prices to reflect current market conditions. Moreover, many producer prices continually rise under existing contracts along with the highest regulated rate prescribed by NGPA price ceilings. Other contract terms specify percent escalation in gas prices over time or tie the current price of gas to residual fuel oil. As a result, wellhead prices to pipelines have risen while pipeline sales have fallen.

Pipelines escape the full impact of rising wellhead prices because the NGPA allows them to automatically pass through wellhead price increases to their main line customers and distributors. Purchased Gas Adjustments (PGAs) are filed with the Federal Energy Regulatory Commission (FERC) up to twice a year to reflect cost increases from rising wellhead gas prices. Insofar as PGAs allow rate hikes to reflect only the price of gas which is sold by pipelines to their customers, some pipelines have elected to sell the most expensive gas to distributors while storing lower-cost gas supplies for sale at a later date. This practice further contributes to the rate of increase in the price of gas sold to distributors and other pipeline customers.

Under current regulatory provisions, distributors behave in much the same manner as pipelines. Some distributors are paying such high prices for natural gas that this gas cannot be profitably sold to their customers. Again, take-or-pay contract provisions of an earlier era, along with the lack of alternative suppliers, restrain distributors from refusing delivery of high-priced gas. In turn, distribution utilities typically pass along rising gas prices to their customers via state versions of PGAs, though these practices have recently met political resistance in some states, such as Michigan.

Recent gas price hikes and predictions of future gas price increases have caused a re-examination of our policies toward gas production and delivery. To many observers, excess production capacity coupled with rising price levels suggests that the gas market should be more responsive to falling demand for energy. Current gas prices to consumers are higher than market clearing levels in spite of and because of NGPA price ceilings and other regulatory features. Take-or-pay contracts and other regulatory policies have transformed NGPA price ceilings into price floors during this current period of slack demand.

Federal legislation to allow producer-pipeline renegotiation of existing contracts has been proposed as one way to remedy gas market irregularities. In addition, diminishing the ability of distributors and pipelines to pass along wellhead price increases through PGAs may give a greater incentive to pipelines to renegotiate onerous contract terms. Other changes include establishing interstate pipelines as common carriers so that local distributors and customers could purchase gas directly from the lowest-cost producer.

The possibility that current wellhead gas prices have risen beyond their equilibrium has given new impetus to those who advocate accelerated decontrol of all wellhead prices. The current tiered structure of price ceilings stifles the incentive to discover new domestic reserves and to enhance production capacity. Price decontrol could lower the resource costs of current production and increase future supplies. In turn, increases in future supplies would lower the extent of future price levels to natural gas consumers. To the extent that price levels currently exceed their market-clearing levels, accelerated decontrol would not raise prices to consumers in the near term so long as amendment of contract features and regulatory policies accompanied such a measure.

Opposition to accelerated decontrol arises from both distributors and consumers who perceive the NGPA as a decontrol action which did little to hold the line on consumer prices. Wary of any new measure that claims to lower prices by allowing an apparent acceleration of current policy, many individuals favor a rollback of current price levels as a guarantee of rational price levels for natural gas.

Forecasts of future price levels and production under market decontrol remain uncertain for many reasons. The volatile behavior of world energy prices carries over to natural gas, a substitute for petroleum use in many sectors. Moreover, the future level of energy demand, including natural gas, is difficult to predict because of the depth of the current recession and the timing of recovery. In addition to these uncertainties of market behavior, removal of present regulatory policies on natural gas will influence market demand and supply in countervailing directions.

Despite the difficulties in predicting gas market behavior under accelerated decontrol, the current price of substitute fuels for natural gas, particularly fuel oil, provides an approximate anchor for a deregulated gas price estimate in the short run. Within the Seventh District states, natural gas prices in 1982 rose to parity with residual fuel oil. This evidence, coupled with the present inefficiencies in natural gas production, suggests that the Seventh District residents would not be seriously affected, on average, by the price effects of accelerated decontrol. Rather, the market signals to producers that accompany decontrol would work to increase future supplies of natural gas and moderate future price increases. Moreover, enhanced domestic energy production presents a major counter punch to OPEC dominance of world energy prices.

Of course, any recommendation to accelerate decontrol of wellhead prices must be accompanied by renegotiation of existing pipeline-producer contracts and revision of other NGPA features. One problem associated with accelerated decontrol involves provisions within existing contracts between transmission pipelines and natural gas producers. One type of contract provision, the "most-favored nation clause", immediately lifts the price of gas to the highest price paid in the well's producing area upon the advent of price decontrol. This can result in above-normal post-decontrol price levels for gas under these contracts because the structure of present regulations can distort the price of gas from nearby deep wells above reasonable levels. Thus, most-favored nation provisions can cause a "fly-up" in gas price above the eventual equilibrium price at the time of decontrol. These contract provisions and others must be amended or renegotiated if accelerated decontrol is to accompany moderate price levels in the near future.

Chapter I: Delivery, Consumption, and Production of Natural Gas

There are four principal agents that bring natural gas from under the ground to the homes and factories of the United States. These agents are wellhead producers, transmission pipelines, distribution utilities, and final customers (Figure 1). Typically, wellhead producers sell their natural gas to interstate or intrastate transmission pipelines under long-term agreements. Allowable prices for all domestic wellhead gas are regulated by the Federal Energy Regulatory Commission (FERC). This regulatory agency administers allowable natural gas prices under the authority of the Natural Gas Policy Act (NGPA), enacted in 1978.

Transmission pipelines serve as an intermediary transport system between wellhead producers and distribution utilities (as well as some large commercial and industrial customers). Transmission pipelines differ from common carriers, such as railroads, in two respects. First, the profits of transmission pipelines are regulated by the federal government so that they can best be considered as public utilities. Second, transmission pipelines purchase the product that they transport from wellhead producers. Pipeline purchase of natural gas serves to secure long-term supplies of natural gas to energy-dependent regions of the country. It has also contributed to certain long-term contract provisions that are hindering short-term declines in natural gas prices during the present recession.

The major portion of natural gas delivered to the Seventh District states is provided via 11 transmission pipeline companies. In the Midwest region, interstate transmission pipeline systems deliver the bulk of natural gas from the Southwestern states of Texas, Oklahoma, and Louisiana (Figure 2). Lesser volumes of natural gas originate from local wells, Appalachian gas fields, and

Figure 1
Principal Agents in the Domestic Market for Natural Gas

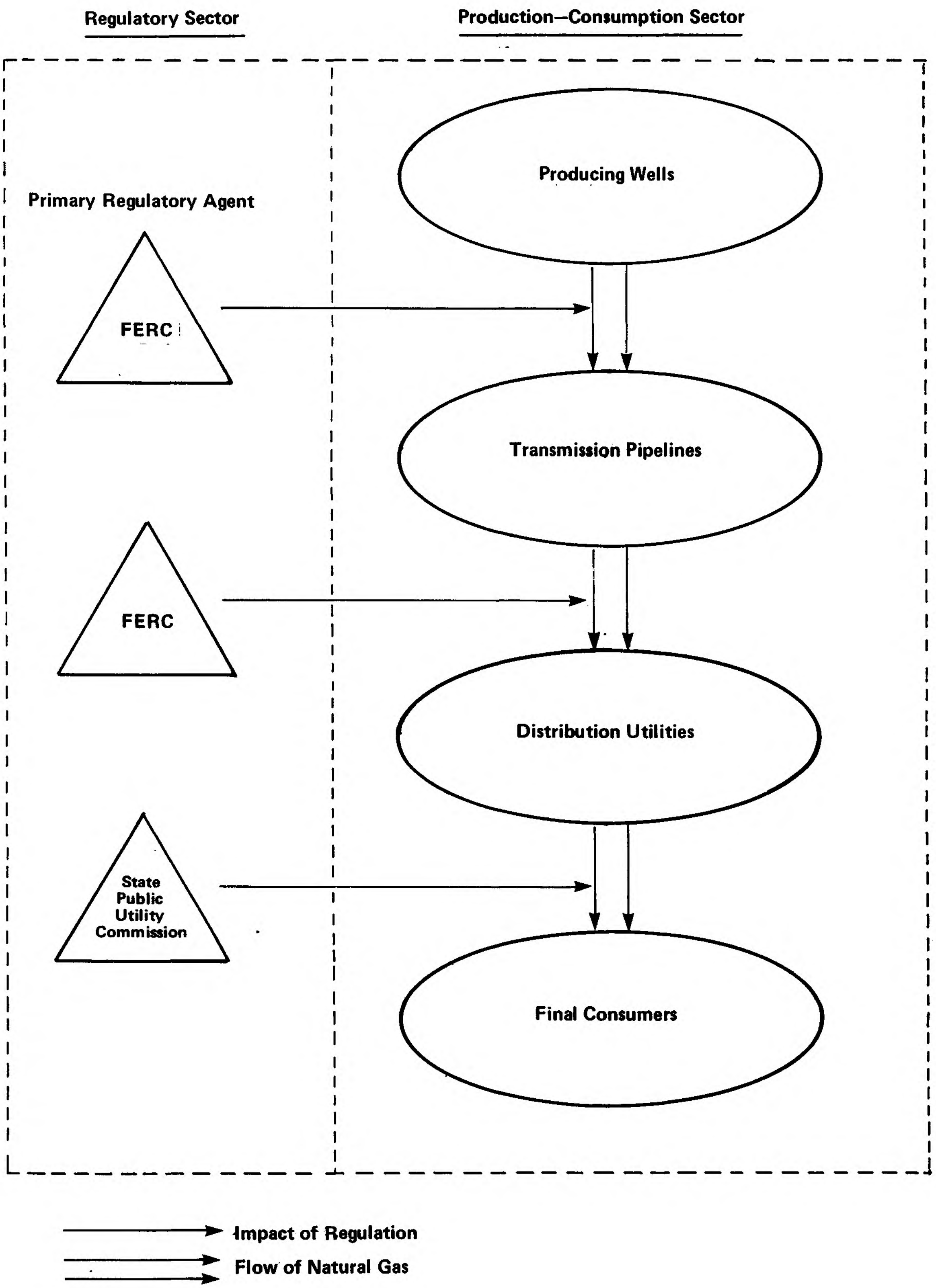
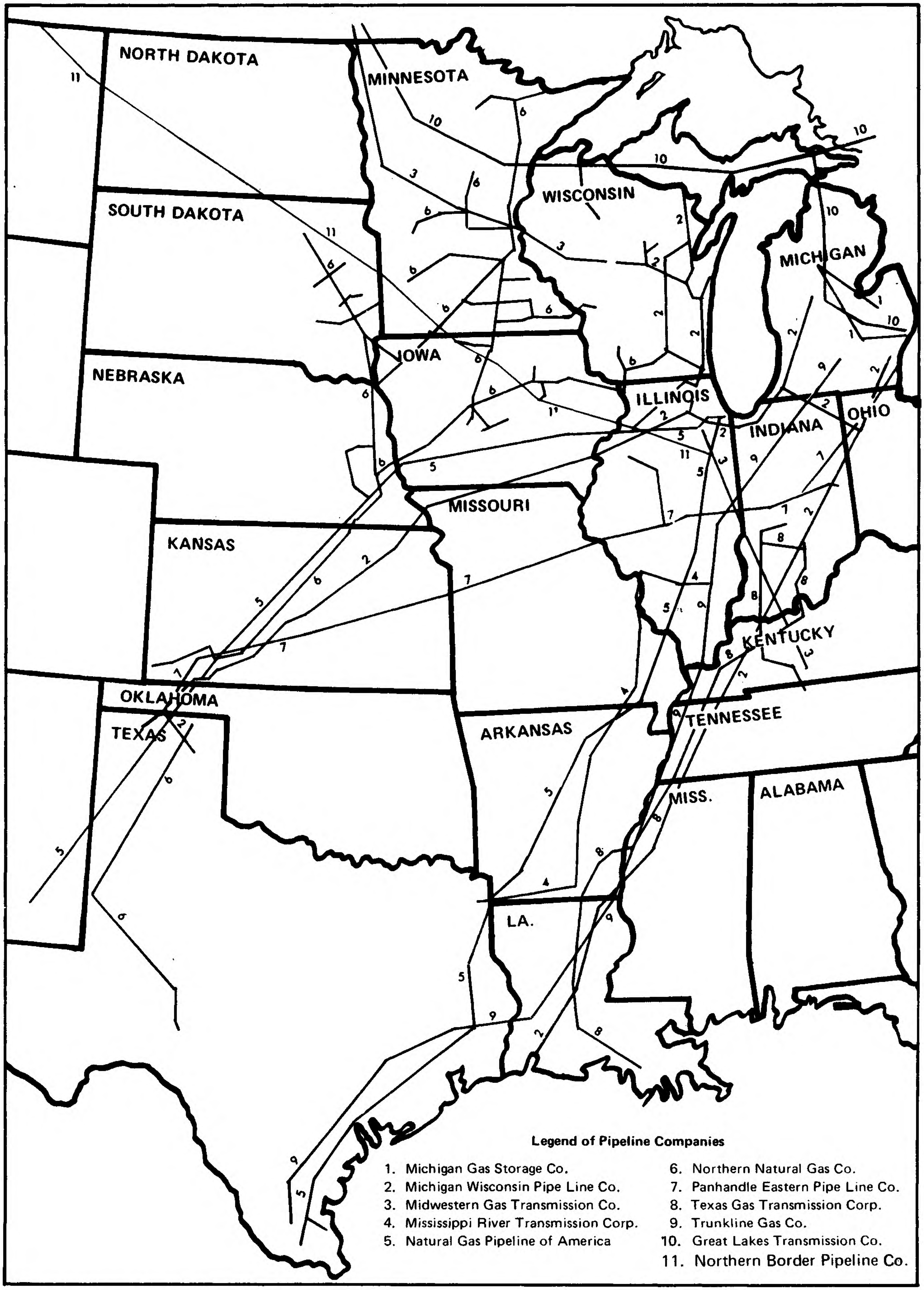


Figure 2
Primary Transmission Pipelines Serving Seventh District States



Source: U.S. Department of Energy, *Major Natural Gas Pipelines*, U.S.G.P.O., 1979.
——— Boundary of Seventh Federal Reserve District.

foreign countries (largely Canada and Mexico). Unlike domestic petroleum consumption, however, U.S. imports of natural gas account for only a small portion of domestic consumption, slightly over 5 percent in 1981.

Transmission pipeline companies generally sell natural gas to public and private distribution utilities as well as large industrial customers and electric utilities. Sales of natural gas by transmission pipeline companies are also regulated by the FERC. Increases on gas costs are passed through to utilities via Purchased Gas Adjustment clauses (PGAs). These clauses, filed with the FERC, are intended to compensate pipeline companies for ongoing increases in the price of gas that are paid to wellhead producers.

Distribution utilities, both public and private, purchase natural gas from transmission pipelines and deliver it to final customers through a network of buried pipes. State regulatory agencies, typically public utility commissions, oversee delivery and pricing of natural gas to final customers. In most states, distribution utilities are able to pass through cost increases of purchased gas to final customers without regulatory approval by way of state versions of PGA clauses. The State of Michigan represents one exception to this practice. Michigan requires public utility commission approval of PGA gas utility rate hikes.

Natural Gas Consumption and Production

In 1980 natural gas accounted for 27.6 percent of overall energy consumption within the five states (Illinois, Indiana, Iowa, Michigan, and Wisconsin) of the Seventh District. This compares with 26.9 percent for the nation (Table I). Contrary to what would be expected in an era of rising prices of imported fuels, national and regional dependence on natural gas has decreased from 1970 to 1980, indicating a general substitution of alternative energy sources for natural gas. The national dependency, which had exceeded

Table I

Natural Gas Dependence by Type of User 1980 (1970)*
(percent)

	Year	All Uses	Residential	Commercial	Industrial	Transportation	Electric Utilities
Illinois	1980	29.5	54.6	36.2	25.1	1.8	1.8
	(1970)	(32.6)	(53.4)	(34.4)	(26.2)	(3.7)	(16.7)
Indiana	1980	20.5	37.0	31.3	19.1	2.1	(--)
	(1970)	(25.1)	(40.0)	(40.7)	(22.0)	(3.0)	(5.6)
Iowa	1980	27.0	35.9	40.4	28.4	5.5	2.9
	(1970)	(40.2)	(45.7)	50.7)	(29.1)	(9.0)	(45.3)
Michigan	1980	32.0	54.1	46.1	25.8	2.0	3.2
	(1970)	(30.5)	(50.9)	(40.7)	(24.2)	(1.8)	(11.0)
Wisconsin	1980	26.4	35.7	37.5	28.2	2.6	3.4
	(1970)	(26.5)	(32.5)	(33.4)	(26.8)	(2.5)	(10.7)
Region	1980	27.6	47.3	38.6	24.1	2.4	2.0
	(1970)	(30.4)	(47.0)	(38.0)	(24.9)	(3.4)	(14.2)
U.S.	1980	26.9	31.9	25.2	27.6	3.3	15.6
	(1970)	(32.6)	(37.3)	(29.5)	(32.9)	(4.6)	(24.8)

*Dependence is defined as dry natural gas consumption as a share of total energy consumption from all fuels. Consumption is measured in MMBTUs (heat content of energy input). The following definitions summarize each use. Residential Sector: energy consumed by private households primarily for space heating, water heating, and other household uses. Commercial Sector: energy consumed by non-manufacturing business establishments, non-profit enterprises, and government. Industrial Sector: Energy consumed by manufacturing, construction, mining, agriculture, fishing, and forestry. Transportation Sector: Energy consumed to move people and commodities in both the private and public sectors. Electric Utility Sector: Energy consumed by publicly-and privately-owned establishments which generate electricity for resale.

SOURCE: State Energy Data Report 1960 through 1980, DOE/EIA-0214(80), July, 1982.

that of the District states in 1970, fell by twice as much as the regional share.

Michigan and Illinois are particularly dependent on natural gas. Michigan's 32 percent consumption share and Illinois' 29.5 percent share are significantly greater than the nation's average. Both Iowa and Wisconsin consume natural gas in close proportion to the national average. Consuming only 20.5 percent of its energy in the form of natural gas, Indiana lies significantly below the national average.

The residential and commercial sectors in Seventh District states are far more dependent on natural gas than the overall nation. All five states maintain a higher proportion of residences with gas heating than the nation's average (Table II). In this regard, Illinois ranks first in the nation and only five other states rely on gas for home heating to a greater extent than the State of Michigan.

Table II

Percent of Residential Units Heating With Natural Gas 1980

State	Percent Housing Units	Rank in U.S.
Illinois	82.5	1
Indiana	61.3	16
Iowa	66.7	13
Michigan	76.5	6
Wisconsin	58.1	21
U.S. Average	53.3	--

SOURCE: U.S. Department of Commerce, Bureau of the Census, "Provisional Estimates of Social, Economic, and Housing Characteristics," Table H-3, Fuels and Financial Characteristics of Housing Units 1980.

Michigan's dependence on gas in the residential and commercial sectors, and its overall dependence, greatly increased over the past decade. Illinois and Wisconsin also witnessed increasing gas dependence in the residential and commercial sectors. As a result, the Seventh District became more gas dependent in these sectors while the nation has experienced significant declines. Within the industrial sector, only Wisconsin and Michigan's gas shares of total energy turned upward, countering both overall regional and national trends. Both the region and the nation showed a reduced dependence on natural gas in the transportation sector between 1970 and 1980. And while the nation greatly reduced its dependence on gas used to generate electricity, Seventh District states reduced gas consumption in this sector to an even greater extent.

The industrial sector consumes the lion's share of natural gas in the United States, over 41 percent in 1980 (Table III). However, in the Seventh District states, especially Michigan and Illinois, the residential natural gas share exceeds other sectors, comprising about 40 percent of regional gas use in 1980. The industrial end-use sector is a close second, representing approximately 35 percent of total regional gas consumption. Overall, the region's gas consumption accrues in the residential and commercial sectors to a much greater extent than the nation. Natural gas is used to generate electricity to a greater degree in the nation than in Seventh District region where coal rather than gas is the primary input.

Regions vary not only in their relative dependence on natural gas but also in their absolute consumption of energy and natural gas. Seventh District consumers utilized about 91,000 cubic feet of gas per capita in 1980, exceeding the national by about 3,000 cubic feet (Table IV). While per capita gas consumption in the region declined by 9,000 cubic feet from 1970 to 1980, per capita consumption nationally fell by over 16,000 cubic feet. Consequently, regional per capita consumption changed from a lower-than-national total in 1970 to an amount in excess of national per capita consumption in 1980.

Table III

The Distribution of Natural Gas Consumption by End-Use Sector 1980 (1970) as a Percent of Total Consumption

	Year	Residential	Commercial	Industrial	Transportation	Electric Utilities	Total
Illinois	1980	43.9	20.9	32.0	1.3	1.8	100
	(1970)	(37.4)	(16.5)	(32.4)	(2.8)	(11.3)	(100)
Indiana	1980	33.4	14.3	49.9	1.8	.4	100
	(1970)	(29.0)	(14.2)	(49.2)	(2.0)	(5.4)	(100)
Iowa	1980	31.5	18.8	42.5	4.7	2.6	100
	(1970)	(27.6)	(16.4)	(28.3)	(5.3)	(22.3)	(100)
Michigan	1980	44.8	22.0	28.8	1.2	3.1	100
	(1970)	(42.0)	(16.4)	(32.4)	(1.3)	(7.9)	(100)
Wisconsin	1980	35.0	21.9	36.8	2.3	3.9	100
	(1970)	(31.1)	(16.1)	(41.7)	(2.0)	(9.1)	(100)
Region	1980	40.4	20.1	35.4	1.9	2.2	100
	(1970)	(35.4)	(16.0)	(35.8)	(2.3)	(10.4)	(100)
U.S.	1980	23.9	13.1	41.2	3.2	18.7	100
	(1970)	(22.9)	(11.3)	(43.8)	(3.4)	(18.6)	(100)

Note: The consumption share is defined as dry natural gas consumption by end-use as a share of all dry gas consumption.

SOURCE: State Energy Data Report 1960 through 1980, DOE/EIA-0214(80), July, 1982.

Table IV

Per Capita Natural Gas Marketed Production and Consumption, 1970-1980

	Consumption[a] Cubic Feet Per Capita			Production[b,c] Cubic Feet Per Capita		
	1970	1980	% Change	1970	1980	% Change
Illinois	105,670.6	95,430.4	- 9.7	436.5	137.8	-68.4
Indiana	104,908.5	89,101.1	-15.1	28.1	84.3	200.0
Iowa	123,539.8	92,512.4	-25.1	0.0	0.0	0.0
Michigan	91,083.0	93,437.4	2.6	4,374.1	17,097.1	290.8
Wisconsin	76,505.2	74,767.7	- 2.3	0.0	0.0	0.0
Region	99,235.7	90,726.2	- 8.6	1,343.0	4,753.3	253.9
United States	103,978.3	87,756.5	-15.6	107,823.3	89,970.6	-16.6

SOURCE: Natural Gas Annual 1980, February 1982, DOE/EIA-0131(80), and State Energy Data Report, 1960-1980, DOE/EIA-0214(80).

[a]Production includes marketed production including nonhydrocarbon gases.

[b]Consumption includes "Lease and Plant Fuel" and "Pipeline Fuel".

[c]Production figures contain nonhydrocarbon gas while consumption figures exclude this gas. Production data, net of non-hydrocarbon gas, is not available for all states.

By all accounts, the Seventh District consumes much more natural gas than it produces. Michigan produces the only significant amounts of natural gas among Seventh District states. Michigan produced over 17,000 cubic feet of gas per capita in 1980, an increase of almost 300 percent from 1970.

Natural Gas Prices in the Midwest

Natural gas prices have risen in approximate unison among states of the Seventh District over the last decade. From 1970 to 1981, retail natural gas prices increased by almost six-fold (Table V). While the nation's gas prices climbed at a compound average annual rate of just over 17 percent over this period, the increase in each District state was slightly lower. Four of five Seventh District states witnessed an average gas price level above the national average in 1970, but only the average price in Michigan and Wisconsin remained above the national average in 1981. Concurrently, Indiana experienced the lowest regional average gas price level in 1981, 11 percent below the national average.

Prior to the NGPA in 1978, national average gas prices rose at a slower pace than in the post-NGPA era. Post-NGPA price acceleration was consistent with NGPA intentions of spurring national gas development to a limited degree through price incentives. Among District states, the average annual growth rate of prices lagged behind the nation in the eight years preceding the NGPA of 1978, a period characterized by restrictive price controls on interstate gas and intermittent supply shortages in the Midwest. In the post-NGPA era, the average annual increase in gas prices exceeded the national average in every Seventh District state except Illinois.

Table V

Gas Utility Industry Average Prices (all customers) 1970-1981
($/millions of btus)

	1970	1978	1979	1980	1981	Compound Annual Rate of Increase 1970-78 (percent)	Compound Annual Rate of Increase 1978-81 (percent)	Compound Annual Rate of Increase 1970-81 (percent)
Illinois	$.73	2.27	2.72	3.26	3.66	15.2	17.3	15.8
Indiana	.71	1.93	2.38	2.82	3.26	13.3	19.1	14.9
Iowa	.62	1.96	2.36	2.81	3.45	15.5	20.7	16.9
Michigan	.78	2.17	2.51	3.06	3.70	13.6	19.5	15.2
Wisconsin	.80	2.26	2.66	3.42	4.19	13.9	22.8	16.2
U.S.	.64	2.18	2.52	3.13	3.66	16.6	18.9	17.2

SOURCE: American Gas Association.

Note: A British thermal unit (btu) equals the amount of heat required to raise the temperature of one pound of water one degree Farenheit.

The price of gas in the highest-priced District state, Wisconsin, exceeded that of the lowest price state, Indiana, by just over 28 percent in 1981. While substantial variation in average price levels between Seventh District states can be observed, the variation among smaller market areas most likely exceeds that between states. In addition to differences in distance from the wellhead, delivery costs differ according to volume with large customers generally being less-costly to serve than others. Differences in retail prices also arise from the variety of transmission pipeline companies serving the region. Transmission pipelines sell natural gas to distribution utilities in the Seventh District at average rates that reflect their ability to secure gas at varying prices within NGPA price ceiling categories. For this reason, local utilities within a state or region may purchase natural gas at significantly different prices than their immediate neighbors.

A recent survey of selected transmission pipeline companies indicates the substantial variation in the mix of purchased wellhead gas by transmission pipeline companies.[1] Among those pipelines selected in the sample that serve the Seventh District states, the highest average wellhead price exceeded the lowest average price by over 62 percent. These price variations largely reflect the historical position of pipelines in cementing long-term contracts for volumes of natural gas at favorable prices and other contract terms.

II. The Federal Regulatory Environment

Two primary goals of current federal legislative policy can be identified, though these goals have not been fully realized. First, legislation has been enacted to protect certain classes of residential and commercial users from a worsened economic position by limiting the rise in the price of natural gas and by insuring delivery priorities to these customers. Although price limitations are intended to protect consumers from deterioration in purchasing power, these same limitations can result in shortages and bottlenecks in supply thus negating the potential benefits to be derived from price protection. To compensate, additional legislative measures insure delivery priorities to preferred gas users, which are primarily residential and commercial customers.

The second goal of current legislation attempts to bring gas production and consumption into harmony with our comprehensive national energy needs. Together with coal development and energy conservation, natural gas development represents a major counterpunch to OPEC dominance of energy supplies and costs. By substituting coal and natural gas for imported oil, we can improve our terms of trade with other countries, and possibly erode OPEC's pricing power.

Although the goals of current natural gas policy are laudable, these goals have not been realized under the market incentives created by the myriad of present regulations. Clearly, current regulations have failed to protect consumers from near-term price increases. Moreover, the development of domestic gas production has fallen short of its potential. The history of gas market regulation in the U.S. reveals a morass of counterproductive intervention and the needless restriction of market forces.

Federal Government Regulation: A Synopsis

Although natural gas deposits were readily available for production early in this century, delivery to large urban markets awaited the technological breakthrough that made natural gas competitive with fuel oil.[2] The development of the seamless welded pipe in the 1920s ushered in the era of natural gas and natural gas delivery systems. Since pipeline systems require large fixed costs, Congress moved to prevent the monopoly pricing of natural gas to local utilities by interstate pipeline transmission companies. The Natural Gas Act of 1938 (NGA; Pub.L. 75-688) gave the Federal Power Commission (FPC) the authority to regulate interstate pipeline gas price and contract terms. Transmission companies that did not cross state boundaries, intrastate pipelines, remained uncontrolled by federal authority.

Under FPC control interstate gas markets grew rapidly through the early 1950s. Standard "allowed rate of return" and "historical cost" price controls on interstate pipelines were not serious impediments to market development and expansion. By 1950, natural gas accounted for about one-sixth of total domestic energy consumption. In 1954, the U.S. Supreme Court altered the structure of gas markets. Contending that wellhead prices substantially affect ultimate consumer prices, the Supreme Court in Phillips Petroleum v. Wisconsin interpreted the FPC's regulatory power as extending to wellhead prices of interstate natural gas.[3] In essence, producers who chose to sell natural gas to interstate pipelines became public utilities while producers who sold to intrastate pipelines market remained largely unregulated by the federal government.

As a result of this court decision, producers experienced two disincentives to develop and sell gas to interstate pipelines. Regulated prices to interstate gas producers began to fall significantly below the market determined price of gas sold to intrastate pipelines. The FPC tried to regulate interstate producer gas prices in a fashion similar to the regulation of prices on gas sold by transmission pipeline companies to distribution utilities. Determination of "historic cost" and "allowable rate of return" for each producer, however, proved to be an overwhelmingly costly and slow process. By 1960 applications for over 2,900 rate increases had been filed with the FPC, but only 10 had been completed.[4] In an attempt to expedite regulatory processes, the FPC adopted "area rate pricing" in the early 1960s. Area rate pricing established consolidated regulated prices for producers within broad geographic areas. Despite improvements in expediting price increases, area rate pricing failed to achieve a balance between intrastate and interstate wellhead gas prices. The pricing differential encouraged drilling in areas served by intrastate pipelines at the expense of areas served by interstate pipelines. As a result, the committed reserves of gas to interstate pipelines declined during the latter 1960s and early 1970s while intrastate reserves remained fairly constant. Insofar as consumption remained fairly level throughout this period, eventual supply shortages in the interstate market became inevitable.

In addition to delays in wellhead price increases, the Federal Power Commission may have aggravated the interstate supply problem in another respect. Once producers committed producing wells to interstate pipelines, they were not allowed to withdraw these reserves from public access without regulatory permission. Although this regulation initially maintained gas that was already committed to interstate markets, it also may have discouraged some producers from committing any new reserves to the interstate market for fear they could not respond to changes in future conditions by selling to alternate buyers. In any event, the stock of intrastate and uncommitted gas reserves remained fairly constant from 1963 through 1977. Concurrently, interstate reserves fell by almost 50 percent.

Two segmented natural gas markets arose in this regulated environment. The intrastate market, located in gas producing states, experienced higher gas prices but plentiful supplies. In contrast, the interstate market was characterized by lower relative prices than the intrastate market but also by dwindling supplies. By the winter of 1972, shortages occurred at places in the interstate markets where market demand at stated prices could not be met by pipeline supply. Severe shortages occurred again in the winter of 1976-77, temporarily closing many factories and schools in the Midwest.

In response to these regulatory failures, Congress moved to redress the severe imbalance in the natural gas market. During 1978 several legislative enactments markedly altered the regulatory environment. The most significant legislative reform appeared as the National Gas Policy Act of 1978 (NGPA). NGPA replaced the Federal Power Commission with the Federal Energy Regulatory Commission (FERC) as the regulatory authority of natural gas distribution. FERC's regulatory authority was extended to intrastate gas production in an effort to partially unify the two markets that had developed over the preceding 25 years. Although market segmentation continued under NGPA regulations, the intrastate gas market disappeared as a vestige of free market production.

Pre-NGPA regulation redirected regional gas consumption away from interstate pipeline regions by capping interstate prices while ignoring intrastate prices. This diverted gas supplies to the gas producing regions of the South and Southwest. The NGPA alleviated supply shortages in interstate pipelines by several methods. First, NGPA caps intrastate gas prices thus diverting greater available supply to interstate markets. In addition, gas production from federal land on the outer continental shelf can no longer be sold to intrastate pipelines.

A primary feature of NGPA was the establishment of an extensive and complex schedule of wellhead price ceilings. These price ceilings vary in their application to interstate and intrastate markets in the present period and in the price decontrol dates in 1985 and 1987 as scheduled in the NGPA (Table VI).[5] Maximum prices also vary according to the physical characteristics of the well, its proximity to other wells, prior commitment to interstate pipelines, and the date of well initiation.

NGPA ceilings on wellhead gas prices apply to all except Section 107 wells, which are characterized by a drilling depth of over 15,000 feet (Prices of gas from Section 107 wells are determined by market forces.) All ceiling prices are allowed to rise at the rate of inflation. "New gas," gas from new wells and gas from those wells placed in production since 1977, rises in price at an additional four percent per year as measured by the GNP deflator. Price ceilings for most new gas are to be eliminated as of January 1, 1985 and some classes of older vintage intrastate gas also become decontrolled in 1985. It is estimated that the wellhead price on 55 to 65 percent of all domestically produced gas will be unregulated in 1985.[6]

In addition to the wellhead ceilings and a price decontrol schedule, the NGPA set forth a scheme of incremental pricing. Incremental pricing allocates the costs of rising wellhead gas prices to certain industrial uses, large

Table VI

Scheduled Decontrol Dates of NGPA Gas Categories*

NGPA Classification	Description	Date of Deregulation
102, New Natural Gas	. certain new onshore wells	1/1/85
	. new onshore reservoirs	1/1/85
	. offshore leases effective after 4/20/77	1/1/85
	. new reservoirs on old offshore leases	not deregulated
103, New Onshore Wells (certain wells started post 2/19/77)	. wells deeper than 5,000 feet	1/1/85
	. wells shallower than 5,000 feet	1/1/87
104, Gas dedicated as interstate pre-11/9/78	. various categories	not deregulated
105, sold under existing intrastate contracts	. all types	1/1/85
106, sales under "rollover" contracts	. interstate	not deregulated
	. intrastate	1/1/85
107, high-cost gas	. wells greater than 15,000 feet drilled after 11/1/79 and other types	11/1/79
	. tight sands and other types	not deregulated
108, stripper wells	. produced at rate less than 60,000 ft^3/day	not deregulated
109, other	. Prudhoe Bay and other	not deregulated
Imported gas	. price set by approval of the FERC and the Economic Regulatory Administration	not deregulated

*In general, wells qualifying under more than one category are eligible for the price ceiling and decontrol status of choice. See Appendix I for a more complete description of decontrol categories and ceiling prices.

industrial boilers in particular. The price of gas sold in these industrial uses, however, may not exceed the regional price of high-sulfur residual fuel oil which is a close substitute for gas in industrial boiler consumption. This latter restriction inhibits the switching of gas for fuel oil to insure greater price subsidization of residential, commercial, and electric utility customers.

Concurrent with NGPA, the Powerplant and Industrial Fuel Use Act of 1978 (FUA) altered the demand for natural gas. The FUA sought to encourage the use of coal, shale oil, and alternate fuels for industrial purposes in place of oil and gas. The FUA prohibits new electric powerplants and industrial boilers from burning oil or gas if coal or other fuels remain an alternative. Exemptions are granted to the extent that alternative fuels are prohibitively costly or environmental regulations deny the use of alternatives.

Through the NGPA and the FUA, Congress intended to steer a middle course between allowing gas prices in the long term to rise to oil-price equivalents and holding down the increases in the short term to protect certain classes of customers. Although the ceilings served to limit the rise in gas prices to residential and commercial customers, Congress foresaw continuing gas shortages in the short run because of the ceilings. Consequently, allocation directives such as curtailment priorities, demand restrictions, and incremental pricing of industrial gas attempted to contain expected shortages to industrial users and electric utilities. At the same time, the removal of ceilings on "deep wells" and the accelerated price increases on new gas were designed to encourage gas development and production in order to foster alternatives to petroleum imports and augment future supplies of natural gas. By increasing future supplies and gradually raising average gas prices, it was thought that protective price controls would become unnecessary. This process of gradual price decontrol was intended to lift new gas prices to approximate parity with oil by the time of partial price decontrol in 1985. In this manner, decontrol would not subject gas consumers to price shocks. A regulatory middle route was fashioned between the development goals of the free market and the immediate necessities of holding consumer prices at bay. Unfortunately, the intentions of our most recent natural gas policy have not been realized in actual market behavior.

III. The Recent State of the Natural Gas Market

A declining domestic demand for natural gas, coupled with certain regulatory features of the NGPA, have given rise to both rapidly rising prices and excess production capacity. Moreover, market regulations of both the pre-NGPA and post-NGPA era have conspired to insulate suppliers of natural gas from falling demand while final consumers of gas bear the costs of unneeded investment in the production of costly gas supplies. These developments have re-opened the issues concerning the regulation of the natural gas industry. Legislative movements are underway to make the supply side of the market more responsive to falling market demand. At the same time, the high level of current gas prices has given new impetus to an acceleration of the current price decontrol schedule. If gas prices currently exceed market clearing levels, accelerated decontrol of wellhead prices, accompanied by legislation that allows the current market to respond to falling demand, may result in more rational production incentives without further price shocks to gas consumers.

Post-NGPA Natural Gas Market Behavior

The scheduled partial decontrol of natural gas, beginning in 1985, was to be preceded by an average gas price that was close to parity with competitive oil products. However, the NGPA schedule of price decontrol did not anticipate the near-doubling in the price of crude oil from 1978 to 1981. As a result, the price of natural gas fell significantly below the price of crude oil in the years immediately following NGPA. At that time, many observers predicted a sharp price spike to accompany partial decontrol in 1985 because natural gas consumption, which is a close substitute for fuel oil in industrial use, was expected to rise as customers switched from oil to gas to lower overall energy costs.

Forebodings of sharp price hikes in 1985 were exacerbated by certain contract provisions between interstate gas producers and interstate pipelines. In anticipation of eventual price decontrol and rising energy prices, gas producers included "escalator" clauses in contracts with transmission pipelines which raise the price of previously committed gas over time. Interstate pipelines accepted many of these contract terms under the duress of looming shortages. Some escalator clauses continually raise prices to the level of the highest allowable regulated wellhead rates which rise as ceiling prices increase over NGPA categories of gas. Other clauses simply include definite percent escalations in future prices of delivered natural gas.

One type of escalator clause, the deregulation provision, causes particular alarm in discussion over price hikes accompanying partial decontrol.[7] At the same time of partial decontrol, these provisions lift wellhead prices of contracted gas to free market rates or to other indefinite levels such as 110 percent of the price of residual fuel oil. In the absence of deregulation clauses, the advent of partial decontrol of gas from new wells in 1985 would witness moderated average price increases because some gas that had been committed prior to decontrol would be locked into low contract prices.

One particular type of deregulation provision, the "most-favored nation" clause, has the potential to cause severe disruption with the onset of partial decontrol in 1985. In general, a most-favored nation clause stipulates that the transmission pipeline pay the average of the two or three highest prices being paid in the producing area or the highest price being paid for similar gas. Pipelines often cannot cancel out of these contracts.[8]

While most-favored nation clauses alone might temporarily throw market prices above their equilibrium in 1985, the NGPA magnifies the impact of these clauses. The price of deep-well gas, Section 107 gas, is currently decontrolled in toto. Many gas pipelines have bid up the price of Section 107 gas because of their practice of average cost pricing. Pipelines generally average the costs of old, low-price gas along with the cost of more expensive new gas to establish a single price to any given distribution utility. Transmission pipelines can use the price "cushion" of previously-contracted cheap wellhead gas to bid competitively for uncontrolled expensive domestic gas or wellhead imports from Mexico and Canada in an effort to meet the demand of existing customers at average prices. As a result, the average price paid for all gas falls below the marginal price paid for deep-well gas by the pipeline. This has led to wellhead prices of $10 per MCF or more for Section 107 gas while average wellhead prices hover around $2.50. In the event that producers require pipelines to take delivery of decontrolled gas at Section 107 prices in 1985 under most-favored nation clauses, wellhead prices could jump significantly above market equilibrium prices. Though price would eventually settle back to equilibrium, the initial price shock could cause serious disarray within the natural gas market.

Some of the early concern over a sudden price jump in 1985 has abated as natural gas prices climbed much faster than anticipated, lowering the extent of potential price hikes. While many gas industry analysts were asserting that acceleration of the decontrol schedule would lessen the economic costs associated with a sharp price spike in 1985, residential gas prices rose by almost 63 percent from January, 1980 to September, 1982. These rapid price hikes were accompanied by falling energy consumption, falling prices for substitute fuels and falling natural gas consumption.

The current recession has lowered domestic demand for all energy products. Total domestic gas consumption declined from 19,877 billion cubic feet (Bcf) per year to 19,404 Bcf from 1980 to 1981.[9] In the first three quarters of 1982, consumption fell by over 6 percent in comparison to the first three quarters of 1981. Decreases in consumption cannot be wholly attributed to downturns in the domestic economy. Year-to-year changes in weather conditions influence gas consumption. Moreover, rising prices themselves encourage conservation by gas customers. Still, prior to the 1981-1982 recession, total domestic gas consumption rose slightly from 19,627 Bcf in 1978 to 19,877 Bcf in 1980 despite a rapid rise in prices. This suggests that the present economic slump may account for part of the recent slack in gas demand.

Despite the recent downturn in demand for natural gas, both consumer and wellhead prices continue to climb. The average wellhead price of gas increased by over 21 percent from September, 1981 to September, 1982 while average residential gas prices rose almost 19 percent. In comparison, average heating oil prices declined by almost 4 percent over the same period and the domestic average wellhead value of crude petroleum declined by over 10 percent.

Rising gas prices accompanied by slack demand for natural gas leads many observers to conclude that gas price decontrol, as exemplified by the NGPA, fails to benefit anyone except wellhead gas producers. Baffled at price increases in the face of slack demand, many consumers maintain that price decontrol allows monopoly rents to accrue to producers with no benefit whatsoever to consumers.

Why Have Gas Prices Continued to Climb?

Natural gas prices have continued to rise in the wake of slack demand for several reasons. First, the second OPEC round of petroleum price hikes in 1979 led to a doubling in world oil prices. Insofar as petroleum and natural gas are substitutes in energy consumption, petroleum price hikes placed upward pressure on the demand and price of natural gas.

The structure of NGPA price ceilings on domestic gas accommodated and exacerbated upward pressure on gas prices in several respects. The NGPA created a price-decontrolled category of gas, Section 107 gas, as a production incentive. Some pipelines used their surfeit of price-controlled gas to subsidize their price bids on Section 107 gas. As the price of Section 107 gas subsequently increased, it helped to pull the average price of gas up to unforeseen levels.

In addition to price increases in Section 107 gas, NGPA price ceilings themselves have grown at a rate outstripping the general rate of price inflation. While ceiling prices on some categories of gas climb at the rate of inflation, the ceiling price on Section 102 gas, (new natural gas), was permitted to increase at an annual rate of 3.5 percent more than inflation through April 20, 1981, and at a rate of 4 percent more than inflation through the end of 1984. As older vintage supplies of gas have been depleted, a greater proportion of production has fallen into NGPA categories covered by higher ceiling prices and into categories with ceilings that rise more rapidly than inflation, greatly contributing to gas price increases to final customers.

In addition to the price ceiling structure of NGPA, the federal gas regulation of an earlier era contributed to recent gas price hikes. Contract terms between pipelines and wellhead producers reflect the relative strength of these two parties in bilateral contract negotiation. In this regard, the tight producer price ceilings imposed on wellhead gas in the pre-NGPA era restricted available reserve commitments by producers to interstate pipelines. In the absence of adequate price rewards, producers were able to bargain for inclusion of "non-price" or "shadow price" conditions into interstate contracts that were entered into during the last decade, including the period immediately following the passage of the NGPA. In an effort to secure adequate supplies in anticipation of growing demand and continuing shortages, pipelines included escalator clauses, take-or-pay clauses, and other unfavorable conditions into their contracts with wellhead producers. In general, these contract clauses have protected producers from unanticipated declines in final market demand, much to the detriment of transmission pipelines, distribution utilities, and especially final consumers.

Escalator clauses continually raise the purchased price of natural gas sold to pipelines. Price escalations can take the form of the highest regulated price allowed under NGPA regulations or they may only specify certain percent increases in wellhead prices over time. While these contract terms alone cannot ratchet prices upward during eras of excess gas supplies, contracts have been accompanied by "take-or-pay" provisions which discourage downward price movements during periods of slack demand. These provisions require pipelines to pay for contracted volumes of gas on a specified schedule regardless of whether pipelines take the gas. Department of Energy surveys indicate that pipelines were most willing to accept take-or-pay provisions in the 1973-77 era, though they apply to over 80 percent of post-1978 contracted volume as well.[10] As a result of these contract provisions, the gas market has not responded to the recent period of slack natural gas demand at the wellhead. The wellhead price of natural gas in the U.S. climbed by over 21 percent from September, 1981 to September, 1982. Concurrently, the domestic wellhead price of petroleum decreased by over 10 percent.

While take-or-pay contract features have assured that wellhead producers do not suffer from recent declines in gas demand, purchased gas adjustment clauses, PGAs, have insulated pipelines from much of the sagging market demand. To date, FERC has granted pipeline price hikes associated with increased wellhead gas costs without major delays via Purchased Gas Adjustments (PGAs). PGAs can be filed up to twice a year to reflect increases in the prices that pipelines pay for gas at the wellhead.

Perhaps more galling to consumers than recent price increases in the presence of falling demand, transmission pipelines continue to purchase high-priced categories of natural gas for resale to customers while available supplies of cheaper wellhead gas remain in storage or in the ground. For example, Columbia Pipeline Co. stopped taking gas from 20,000 low-volume wells in Appalachia which was available at prices as low as $.45 per Mcf. At the same time, the pipeline continued to purchase gas from other sources at prices exceeding $5.00 per Mcf. These practices have raised the average price of gas that pipelines sell to distribution utilities.[11]

Pipelines are thought to decrease their takes of low-cost gas during periods of slack demand because PGAs only allow a price pass-through for wellhead gas that is sold by the pipeline to a distributor or other customer. In turn, pipelines may seek to preserve a favorable cash flow by receiving PGA compensation for the largest possible portion of their expenditures. High-priced gas, usually being of more recent vintage, is more likely to contain high take-or-pay provisions, reducing the incentive for pipelines to sell older low-priced gas to distributors in place of high-price gas contracted under take-or-pay provisions.[12]

In addition to costs arising from take-or-pay provisions and other contract terms, pipelines incur large fixed costs due to pipeline construction maintenance, and operation. These costs are also rolled into customer prices. In fact, any costly venture can be potentially rolled into final consumer prices. For example, in the 1970s Panhandle Transmission Company and its Trunkline subsidiary heavily invested in facilities to import liquified gas from Algeria in anticipation of severe gas shortages in the 1980s.[13] In addition, pre-construction costs from the Alaska gas pipeline venture and a Wyoming synthetic fuel project led to large sunk costs. No matter the availability and price of domestic wellhead gas in coming years, Panhandle's midwestern distributors and main line customers will bear some of these investment costs because regulatory agencies will allow Panhandle to raise prices to achieve a fair rate of return on all investments, good and bad.

Distribution utilities usually have little choice in paying increased pipeline prices. First, distribution utilities themselves have often signed contracts containing high "takes" from transmission pipelines. Distributors served by interstate pipelines have agreed to contract terms under the similar duress of anticipated shortages in supply that interstate pipelines experienced in the 1970s.

One additional market feature enhances the ability of pipelines to pass on price increases to distributors. Unlike petroleum pipelines, gas transmission pipelines are not common carriers. Hence, even if distributors are not hampered by high "takes" of expensive pipeline gas, they are not free to purchase less-expensive gas directly from producers because their pipeline connection may refuse transport of this gas at reasonable prices.

Distribution utilities pass through price increases to final consumers of gas in much the same manner that distribution utilities pass through price increases in wellhead gas. State public utility commissions usually maintain their own versions of PGAs to reflect ongoing price increases resulting from increased wellhead costs.

Despite the apparent ability of pipelines and distributors to pass higher costs on to consumers, many pipelines and distribution utilities worry about a cost squeeze resulting from recent slack gas demand and rising producer prices. Price increases by utilities and pipelines can be met by consumer resistance in both the market and political arenas.[14] For example, voters in Michigan recently passed a ballot issue to abolish automatic fuel and gas adjustment clauses and to limit the number of rate cases the commission can hear at one time. Legal challenges by consumer groups can delay or minimize expected price hikes by gas pipelines as state public utility commissions become reluctant to increase allowable rates in the face of consumer outrage. Transmission pipeline companies may confront similar difficulties in rate cases held before the Federal Energy Regulatory Commission.

In addition to unyielding regulatory commissions, pipelines and distribution utilities can suffer from sudden declines in demand as natural gas prices approach parity with residual fuel oil. In particular, industrial customers often switch to fuel oil when it becomes more economical than gas. These consumption swings force utilities to spread the fixed portion of delivery costs (and take-or-pay provisions) over fewer customers thus raising the delivered price of gas further still. However, the greater the price elasticity of demand for natural gas, the greater the consumption swing to utilities resulting from changing prices. In some instances, price increases of any magnitude cannot preserve a profitable position for pipelines or utilities as total revenues decrease with loss of volume.

Many distribution utilities are attempting to design rate structures to limit load loss by discounting rates charged to those customers with the most elastic demand. Typically, discounts are offered to industrial customers to discourage their switching from gas to alternative fuels such as fuel oil or to prevent actual plant closings.[15] These discounts are often unpopular with the general public. But to the extent these discounts maintain a utility's volume of gas deliveries, the discounts can limit price increases to all gas customers by spreading fixed costs and the operating costs of utilities over a greater volume of customers. State and federal authorities are often reluctant to approve these price schemes, however, because such price-discrimination practices may maintain high gas volume by imposing proportionately higher prices on politically sensitive consumers, especially residential customers.

Although all gas customers are vulnerable to rising gas prices, residential customers may have the most cause for concern. Residential gas demand is generally more inelastic in response to price rises because these customers are less able to substitute alternative fuels to reduce energy bills. In contrast, some industrial users, such as industrial boiler customers, can easily switch to alternative fuels in response to gas price hikes. As industrial customers switch to alternative fuels, typically residual fuel oil, the fixed costs of pipeline and distributor operations are increasingly borne by commercial and residential customers.

Issues in the Current Policy Debate

Recent price increases and speculation over price jumps accompanying 1985 decontrol have greatly expanded public discussion surrounding gas policies. In addition to concern over the increasing burden of higher gas bills, concern over NGPA-induced inefficiencies has grown. The Reagan administration has directed energy policy toward a greater free market orientation. Those that favor free market policies, including immediate decontrol of all natural gas, point out the market distortions and inefficiencies that NGPA has cost the nation.

One inefficiency arises from NGPA's decontrol of deep-well gas that has created a so-called "market-ordering" inefficiency in production. Insofar as deep-well gas remains free from price controls at the same time that other gas prices are capped, some production of high-cost deep-well gas is exploited in place of low-cost gas. For an equal output of gas, fewer of society's resources could be spent by extracting gas under a single-price scheme.

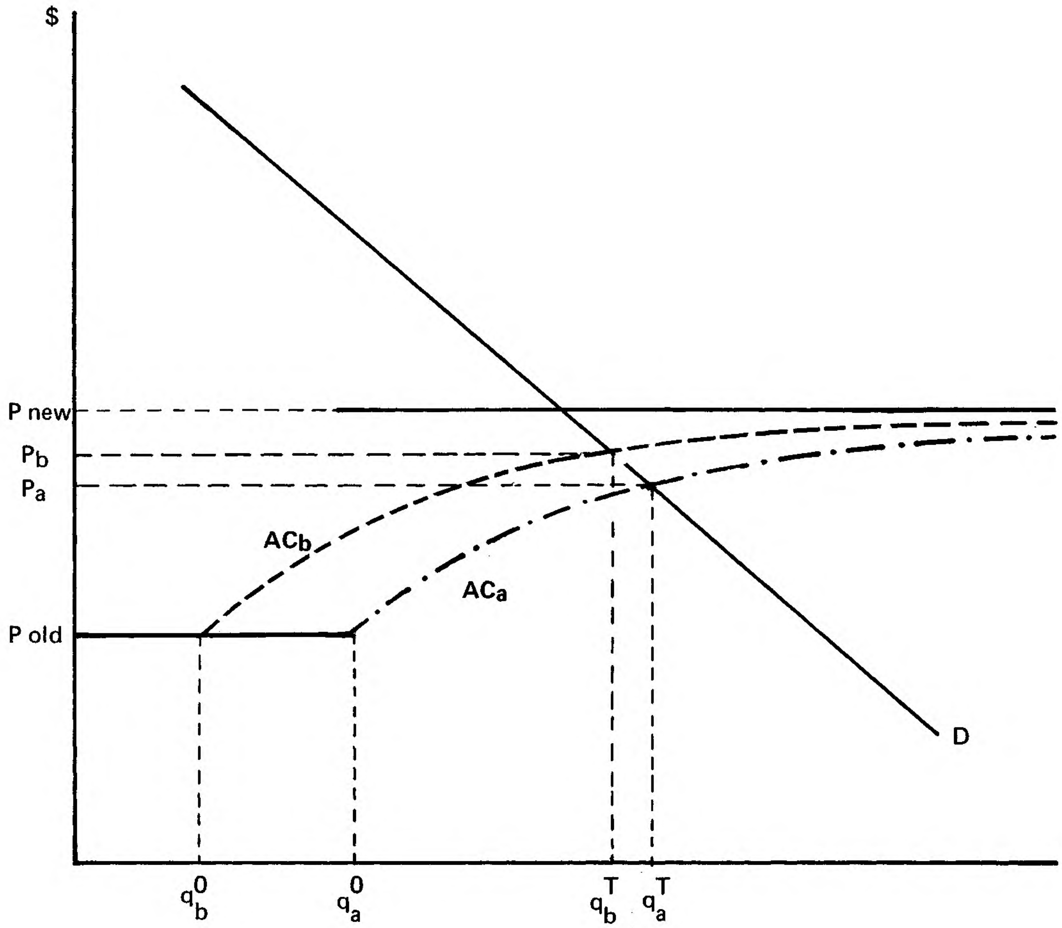
This inefficiency is aggravated by pipelines' average cost pricing practices which foster extra-marginal bidding on deep-well gas. Pipeline companies use cost savings derived from low-cost, long-term gas contracts for old gas as a cushion to bid in the deep-gas market. As a result, much of the cost-savings resulting from price limits on older vintages of gas are used to subsidize extensive production of deep-well gas rather than to lower average gas prices to gas customers.

A second perceived inefficiency stems the from regional allocation of gas supply under NGPA pricing. Pre-NGPA regulation redirected regional gas consumption by capping interstate prices while ignoring intrastate prices. This diverted gas supplies to the gas producing regions of the South and Southwest. Pre-NGPA regulation allowed intrastate prices to rise and plentiful intrastate supplies followed.

The NGPA alleviates supply shortages in interstate pipelines by several methods. First, NGPA caps intrastate gas prices thus diverting greater available supply to interstate markets. Second, gas production from federal land on the outer continental shelf can no longer be sold to intrastate pipelines. This limits supply to intrastate markets and increases available supply in interstate markets. Third, NGPA harbors gas price "cushion" disparities among regions. Those pipeline companies that are in the fortunate position of holding long-term contracts for cheap, old gas or that are supplied by committed reserves of controlled interstate reservoirs hold a larger price cushion to bid for decontrolled gas. As a result, high-cushion pipelines can supply greater quantities of gas to customers at a lower price.

To illustrate, consider two pipeline companies , A and B (Figure 3). Suppose that both pipeline companies face the same customer demand and that each company charges a single average price. The pipelines differ, however, in the amount of cheaper gas that was previously purchased under long-term contracts at the old price P_{old}. As shown in Figure 3, pipeline company A receives the amount q_a^o of old cheap gas in the present period while pipeline company B can only buy cheap gas in the amount q_b^o. Any other gas supplied to customers by pipeline companies must be purchased at the market-clearing, decontrolled price P_{new}. To the extent that pipeline A averages a larger quantity of cheaper gas into its price, it is willing to supply greater quantities of gas at any given price. Hence, Pipeline A's average cost supply schedule, AC_a, is lower than that of Pipeline B, AC_b. If pipeline companies choose to purchase new gas up until the point where all customers are satisfied with available gas at an average price, customers of pipeline A receive total gas supply q_a^T at the lower price P_a. In contrast, if both pipelines maintained the same cushion (the same amount of cheaper gas), gas deliveries and price would be identical in regions served by pipelines A and B.

Figure 3
Results of Inter–Regional Disparities in Quanities of Price–Controlled Gas



Regional disparities in price cushions distort delivery, both between intrastate and interstate pipeline areas and among interstate pipeline areas, by directing supply to large-cushion regions. Interstate pipelines tend to hold greater price cushions than intrastate pipelines owing to a longer history of regulation in that market. The disparities among interstate pipelines can also be substantial. A 1981 Department of Energy survey reveals that some interstate pipeline companies pay up to twice as much to acquire gas compared to their counterparts with less expensive proportions of old, new, and decontrolled gas.[16]

Although regional gas allocations are certainly redirected under NGPA regulations, the NGPA allocation may well represent a significant improvement over the pre-NGPA allocation. Shortages and curtailments in gas delivery have vanished from intrastate and interstate markets alike, though the present recession and above-equilibrium gas prices may be largely responsible for the current gas glut.

The size of the old-gas cushion disparities between intrastate and interstate pipelines will increase under the present decontrol timetable. Some categories of old intrastate gas are decontrolled in 1985 while old interstate gas price controls remain, increasing the size of interstate cushions of lower-priced gas. To the extent that NGPA regulations distort the free market location of gas delivery, advocates of accelerated decontrol argue that these inefficiencies should be removed to promote national economic growth and development.

Other advocates of accelerated decontrol point out that a potential "fly-up" of gas prices in 1985 and beyond will throw gas-dependent commerce into a tailspin. As an alternative, accelerated decontrol will smooth out the inevitable price hike, enabling commerce to more easily adjust to higher prices over time. In addition, accelerated decontrol will moderate future gas price levels by bringing rational production incentives to producers. For example, one analyst forecasts that, in addition to smoothing price climbs over the coming years, immediate decontrol will lower the eventual level of prices confronting consumers by the latter 1980s.[17] This assertion derives from an estimated stifling of gas exploration under current NGPA guidelines. Insofar as the NGPA decontrols wellhead prices for deep-well gas only, companies explore and drill in some decontrolled fields with relatively lower pay-offs in reserves than price-controlled fields. As a result, lower additions to gas reserves are estimated to ensue through 1985 under present controls, raising the eventual price of natural gas.

Although some observers have advocated an acceleration of the NGPA schedule since its inception, decontrol has gained recent momentum from the current market conditions of slack demand and rising prices. To the extent that these market conditions indicate market prices above their market-clearing levels, it is argued that accelerated decontrol can be attained without a price increase to consumers. To accomplish this end, complementary legislation, such as permitting renegotiation of take-or-pay contracts and amending PGA clause procedures, must accompany accelerated decontrol.

At the same time that market inefficiencies have heightened the interest of some observers for accelerated gas decontrol, others have increased their support of continued controls under NGPA. Some even go so far as to advocate the extension of price controls beyond current NGPA mandates and the imposition of immediate price ceilings on all wellhead prices of natural gas.[18] It is argued that consumers have suffered enough from recent gas price jumps. The spectre of presently climbing residential and commercial fuel bills leads to arguments that decontrol of gas awaits a future date, a date that is approached by a long transition of gradually rising prices. Views favoring continued controls are largely based on the belief gas prices would indeed rise under accelerated decontrol, much as prices have risen in the post-NGPA era.

Whether or not the federal government moves to accelerate the NGPA schedule of wellhead gas, other changes in regulatory policy will be considered to make the gas industry more responsive to falling gas demand. These include conversion of interstate pipelines to common carrier status so that distributors and main line customers can choose among alternative suppliers of natural gas. Federal legislation to lower the obligations of pipelines to take delivery of high-priced gas under existing contracts presents another possible remedy. In addition, the incentive for pipelines to voluntarily renegotiate existing contracts and discontinue practices of selling high-priced gas to customers when low-priced gas is available may be established by making it more difficult for pipelines to pass along cost-increases of wellhead gas through PGA clauses.

Both federal and state government will also consider rate designs that allow pipelines and distributors to offer discounts to large industrial users and electric utilities who are on the verge of switching from gas to fuel oil consumption. In the absence of properly-designed rate structures, load loss may foist a larger share of pipeline and distributor costs of gas delivery onto commercial and industrial customers. As an alternative method of restraining price increases to residential and commercial customers in the face of excess delivery capacity, state regulators may decide to lower the rate of equity return to pipelines and distributors by limiting the size of future rate hikes in gas prices.

IV. The Market Outlook Under Natural Gas Decontrol

Predictions of equilibrium price and consumption of natural gas under decontrol are uncertain for several reasons. First, removal of NGPA price ceilings alone will not remove current contract clauses that may be preventing possible declines in short-term prices. Hence, consideration of decontrol pre-supposes complementary legislation to allow renegotiation for existing gas production. Above and beyond this, freeing the restraints of current regulations including wellhead price ceilings, FUA use restrictions and incremental pricing, releases countervailing forces on demand and supply which are difficult to measure.

Despite the difficulty in untangling the complex knot of current regulatory forces, free market prices of gas can be loosely tied to the price of substitute fuels. To the extent that natural gas substitutes for other fuels, such as residual fuel oil, price estimates of gas can be aligned to existing market prices of these fuels. Insofar as world petroleum prices are volatile, price estimates beyond the near term become increasingly poor. In the near term, however, these prices serve as a probable indicator of market prices for natural gas. Using the average energy-equivalent price of residual fuel oil as a barometer, it is doubtful that average natural gas prices in the U.S. and in Seventh District states would rise significantly in response to accelerated gas decontrol.

Market Effects From Removal of Regulations

The effects of deregulation on gas consumption and price under accelerated decontrol are somewhat uncertain for several reasons. First, over the past 40 years, tight regulatory controls distorted gas production, delivery, and consumption. As a result, recent experience cannot foretell the behavior of buyers and sellers confronted by market signals to produce, conserve, and switch consumption among alternative fuels. Second, the preceding decade witnessed an enormous upheaval in energy markets due to cartelization of the petroleum industry. Both buyers and sellers are continuing to adjust to ten-fold price increases. Moreover, insofar as the prices of all energy products tend to move in unison, continued volatility in world oil markets lends additional uncertainty to gas price forecasts. Finally, the world economy lies amidst the deepest recession since the 1930s. Concurrently, the booming energy industry has slumped. Both the timing and strength of economic recovery remain uncertain. For these reasons, accelerated natural gas decontrol may unleash market behavior that is accompanied by either allied or countervailing market forces.

On the demand side of the market, gas decontrol will directly raise demand by lifting remaining FUA restrictions on gas use by industries and electric utilities. Generally, this would tend to raise market price and quantity. In some regional markets, however, increased loads could spread utility fixed costs over greater volume, actually reducing final prices in the near term.

The elimination of incremental pricing to industrial customers will encourage their consumption. At the same time, however, elimination of incremental pricing will tend to raise the price to residential customers, discouraging gas consumption by this sector. Depending on the elasticities of demand and market shares among these groups of customers, lifting of FUA provisions can either raise or lower the overall demand schedule for natural gas.

In the past, regulatory provisions may have dampened gas demand in a less direct fashion than by imposing use restrictions and incremental pricing. Potential gas customers, especially industrial users, could not be assured of adequate long-term gas supplies. Price controls on wellhead gas foreshadowed future shortages to users because producers might withhold gas from the market in the event that controlled prices did not guarantee profits. Wellhead price controls also led to declining drilling activity and proven reserves, a further warning of eventual shortages. Insofar as residential customers comprised a sizable market share, political realities indicated that shortages would primarily impinge on industrial customers. These market conditions, along with direct user limitations on certain customers, indicate a present pent-up, albeit uncertain, demand for natural gas by some industrial customers.

While decontrol of the natural gas market will tend to raise demand, market forces that reduce demand may coincide with decontrol. The demand for all energy sources--including natural gas--has tended to become more elastic (it has fallen) in response to the sudden energy price rises of the 1970s. In the near-term, demand is inelastic or unresponsive to price increases. As time passes, however, buyers discover substitute goods (including conservation) for higher-priced commodities, and reduce demand in response to increased prices. This tendency occurs no less with energy than other goods. Energy consumption declined by almost 4 percent from 1979 to 1980 and by almost 3 percent from 1980 to 1981. While it is difficult to ascertain the extent to which current slack energy demand merely reflects a temporary downturn in the world economy, the demand for gas may decline in response to price increases of the past several years as energy conservation continues.

Similar to natural gas demand, the supply of natural gas can either increase or decrease in response to decontrol. Generally, supply responds positively to price increases. As the wellhead price of gas rose over the 1970s, however, evidence suggests that the supply response was generally disappointing despite tremendous exploration and drilling activity. From 1974 to 1981, the domestic average wellhead price of gas increased by over eight-fold from 21.6 cents to $2.06 per thousand cubic feet, greatly exceeding the rate of increase of overall prices. In response to these price incentives, new domestic gas well completions more than doubled from 7,240 wells in 1974 to 17,894 wells in 1981. Unfortunately, the average production capacity of new gas wells has greatly diminished over the past decade. Additions to proven reserves have not kept pace with current production, contributing to a declining stock of proven domestic gas reserves of almost 15 percent over the same period.

Although rising average wellhead price levels have not halted declining domestic reserves, price structure rather than price level may be the cause. Much of the observed increase in average price over the past few years reflects the decontrolled price of deep-well gas which has climbed as high as $10 per thousand cubic feet in comparison to regulated wellhead rates for new shallow gas of only $2-3 per thousand cubic feet. By encouraging exploration of deep-well gas at the expense of other gas, NGPA may have lessened the reserve payoff per average dollar of exploratory activity.

On the other hand, wellhead price ceilings on older vintages of gas have stimulated overall production and exploration by channelling price savings of pipelines from price-controlled purchases into price bids for deep-well gas. Inasfar as transmission pipelines roll controlled gas prices into average prices, pipelines use the difference between average and controlled prices to bid higher prices for decontrolled gas, stimulating production of these categories. For example in Figure 4-a, the domestic supply curve of gas is represented by the marginal cost schedule, MC, of wellhead producers. For simplification, this schedule is composed of only two types of gas, controlled gas and decontrolled deep-well gas. A kink occurs in the MC schedule at price $\bar{p}_c$ where controlled gas is not forthcoming at higher general price levels because price controls render further production of this class of gas unprofitable.

Beyond quantity $\bar{q}_c$, production only represents the supply of decontrolled deep-well gas. Transmission companies attempt to fill desired demand at average cost along the schedule AC where average cost at any quantity is a price-weighted average of controlled gas and decontrolled gas. This average cost is represented below in equation (1):

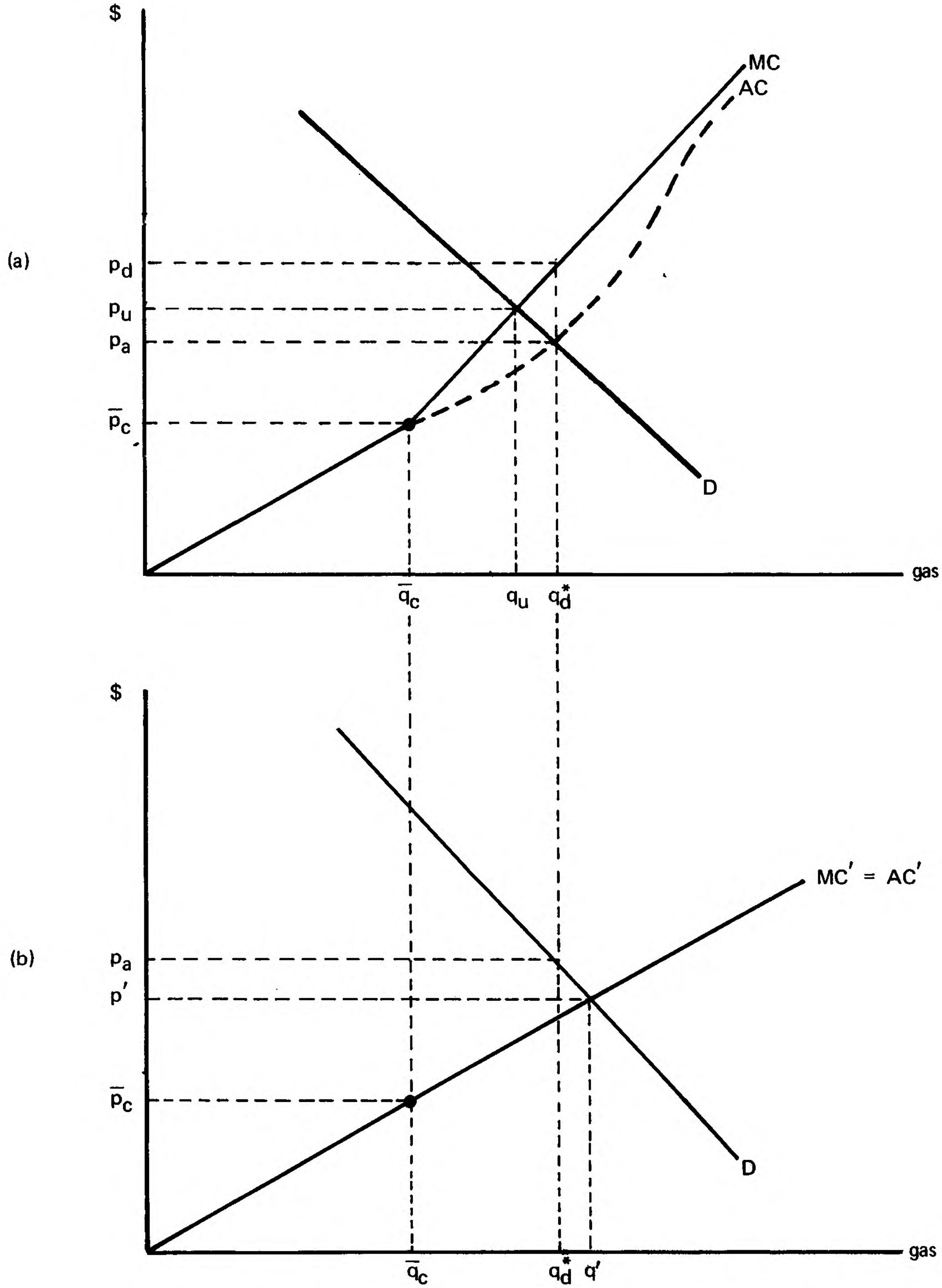
$$(1)\ AC = \frac{\bar{p}_c\bar{q}_c + p_d(q^*_d - \bar{q}_c)}{q^*_d}$$

where $\bar{p}_c$ is the average ceiling price of gas and $\bar{q}_c$ the quantity of gas forthcoming at the ceiling price. The symbol p_d represents the price of decontrolled gas and $q^*_d - \bar{q}_c$ the production from wells not under control. These latter amounts are assumed to be determined by competitive market behavior. The price of decontrolled gas, p_d, at any equilibrium quantity, such as q^*_d, can be read off the MC schedule. Only at a price, such as p_d, will additional gas, $q^*_d - \bar{q}_c$ be forthcoming to satisfy consumer demand at the average price, p_a.

Total market deregulation will influence gas supply by moving toward a more uniform price for all gas. This will affect price and quantity in two respects. First, the average cost schedule will tend to coincide with the marginal cost schedule at the present position of the MC line in figure 4-a. Insofar as transmission pipelines no longer can use price cushions on controlled gas to bid high prices on decontrolled gas, the price of deep well gas will fall from p_d to p_u along the MC schedule to the intersection of

Figure 4

The Price Impact of Average Cost Pricing in the Presence of NGPA Price Ceilings



$q_d^* - \bar{q}_c$ = equilibrium production from wells not subject to price controls.

p_d = equilibrium price of uncontrolled gas.

p_a = average price of gas in equilibrium under NGPA.

p_u = post-decontrol equilibrium price of gas if production of formerly-controlled NGPA categories of gas remain constant after decontrol.

p' = post-decontrol price of gas assuming increased production of NGPA categories that were formerly controlled.

q' = post-decontrol production of gas assuming increased production of NGPA categories that were formerly controlled.

q_u = post-decontrol production of gas if production of formerly-controlled NGPA categories of gas remain constant after decontrol.

demand and marginal cost while the price of decontrolled gas, $\bar{p}_c$, will rise to the same unified price, p_u. At the same time, marketed production will tend to fall from q_d^* to q_u. On average, price has increased from p_a to p_u and production has declined from q_d^* to q_u. As a second countervailing force, however, the marginal cost schedule will tend to push further to the right as the production of additional old shallow-well gas becomes profitable and enters the market at a price higher than $\bar{p}_c$. This is illustrated by a rightward extension of the MC schedule beyond its present kink in Figure 4-a to a position represented by the line MC'=AC' in Figure 4-b. Supply increases will tend to lower average price to p' and increase production to q'.

As constructed in figure 4-b, total market decontrol lowers average price from p_a to p' and increases marketed production from q_d^* to q'. These results depend on optimistic assumptions concerning increased production of newly-decontrolled categories of natural gas. If, on the contrary, the new market supply schedule, MC'=AC', shifts outward to a much smaller degree, the average price of natural gas will rise and production fall in the post-decontrol period. This latter scenario may be more likely in the period following deregulation because a time lag may exist between the time of deregulation and the time when exploration and drilling of price-decontrolled wells start producing. Nevertheless, increased supplies of newly-decontrolled gas may immediately follow regardless of exploration-production lags if well owners are withholding gas production in expectation of price decontrol.

The Price Effects of Decontrol on Average Price in the Seventh District

Despite the many market complications, some observers believe that the price of gas will eventually settle at an energy-equivalent price of a close substitute, residual fuel oil.[19] Low-sulfur residual fuel oil and its residential counterpart, home fuel oil, substitute for natural gas as general boiler fuel for producing heat. Homes and commercial buildings burn both gas and fuel oils for space heat; electrical utilities burn them to generate turbines, manufacturers use both as a steam boiler fuel, and some industrial users substitute either fuel for process heat equipment. If fuel oil prices remain in excess of gas prices to some final consumers, decontrol may be accompanied by substitution of natural gas for oil up to the point where gas prices are bid up to parity with oil at the burner tip. In many regions of the U.S., recent gas price increases have led to switching of fuel oil for gas by industrial users and electric utilities. On average, however, the national price of gas at the burner tip presently remains below residual fuel oil.

The extent that gas price will approach parity with fuel oil under accelerated decontrol crucially depends on the ability of gas to economically replace fuel oil. Potential customers may realize large costs in converting to gas burning facilities. If these costs are small enough so that some conversion to gas still occurs, the end-user price of gas must remain below fuel oil price to compensate new customers for conversion costs. Gas prices and consumption will rise but not to parity with fuel oil.

In the cost extreme, gas might not physically substitute for fuel in enough applications to raise gas price or consumption to any significant degree. For example, within the transportation sector, gas cannot currently replace oil in most uses because the internal combustion engine cannot yet efficiently burn natural gas. If the transport sector were the only energy sector, the demand for gas would remain low relative to supply. Consequently, gas price would lie below fuel oil on an energy-equivalent basis. In those end-use categories of transport that were capable of burning gas, the low gas price would induce gas conversion and completely crowd petrol use out of these sectors.

In contrast, if enough end-users can quickly and easily switch from fuel oil to natural gas upon decontrol, natural gas may rise to complete parity with fuel oil. Under this scenario, gas market decontrol eliminates excess demand for gas by allowing producer and consumer prices to rise. As prices rise, some greater production ensues from high-production-cost producers. At the same time, higher prices ration greater available supplies to those customers who are willing and able to pay market prices. Buyers bid up gas prices to oil price parity because it is economical to do so if gas prices remain below oil parity.

In the short-term, there is even a possibility for natural gas prices to overshoot residual fuel oil prices. If certain classes of customers reduce gas consumption in response to either recessionary business conditions, moderate weather conditions, or to past price increases that encourage conservation of energy, local utilities and transmission pipelines may attempt to spread fixed costs over remaining volume by raising retail prices. Price levels that cover total utility costs may subsequently exceed the costs of alternative fuels, such as residual fuel oil. Short-term inelastic demand of certain classes of customers, will prevent loss of the entire market and sustain higher-than-equilibrium price levels.

[illegible] utilities following [illegible] moderate future price levels to all customers by preventing fuel-switching by some categories of gas users.

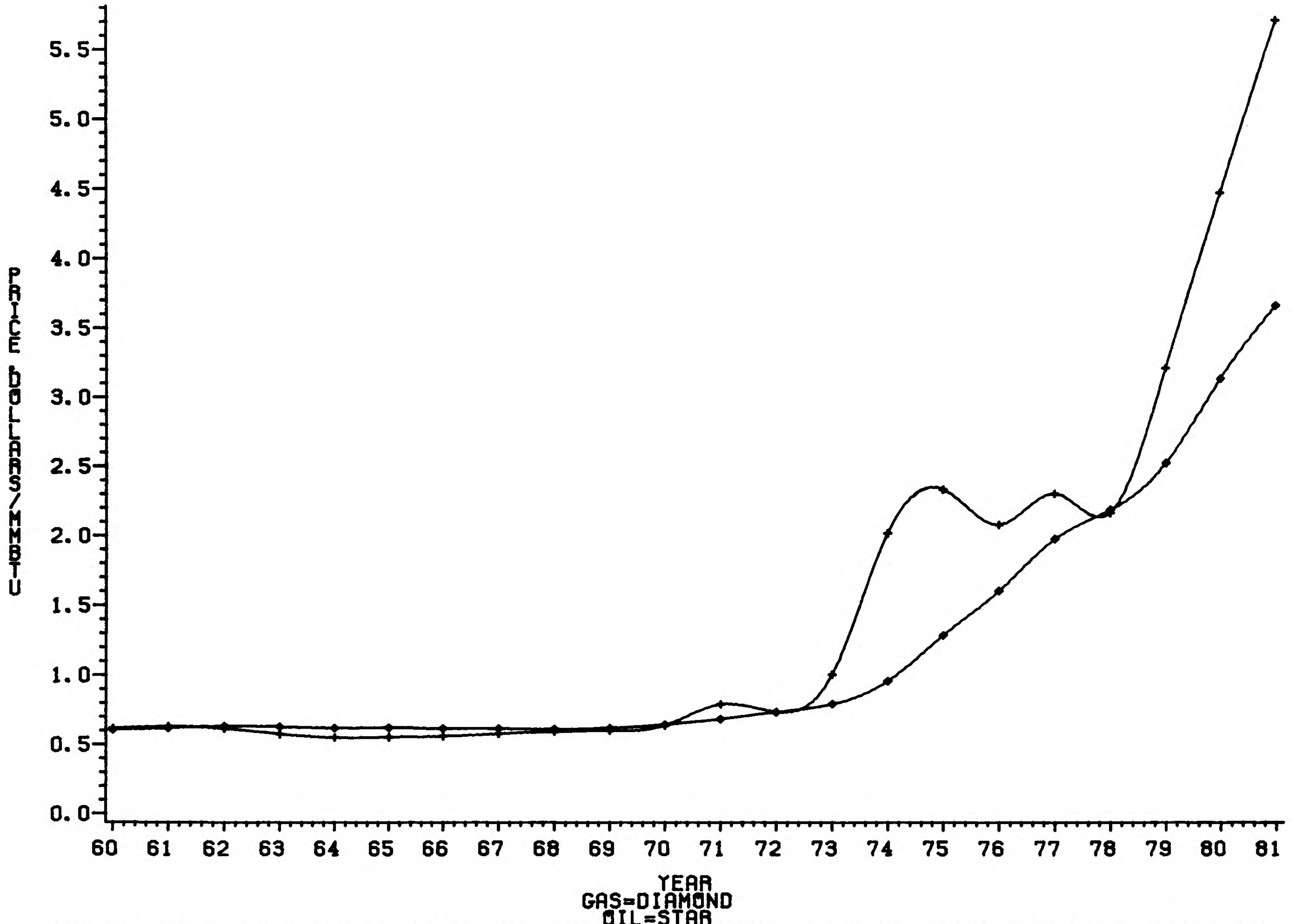
From 1960 to 1972, the energy-equivalent prices of residual fuel oil and natural gas remained close to parity. Estimated gas price actually exceeded fuel oil price for several years in the mid-1960s (Figure 5). Over the last few years, however, the latest OPEC-induced price hike, along with domestic oil decontrol, have caused the price of residual oil to pull away from natural gas. Although this gap has narrowed recently because of softening oil prices and rising gas prices, the domestic price of residual oil remained almost 39 percent above the energy equivalent price of natural gas in 1981.

In the recent past policymakers have become concerned that gas price decontrol would sharply lift gas prices to parity with residual fuel oil. This suggested that decontrol be phased in gradually to defuse large and sudden price hikes. Recent evidence indicates that the sharp gas price hikes to fuel oil price parity no longer lie at issue, except those that may arise from indefinite price escalator contract clauses, because gas prices have already soared beyond expectations. In the Northeast Region (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, and Pennsylvania), for example, natural gas price has settled at parity or above for the last two years.[20] In other regions of the country, a confluence of recent events brought gas prices close to parity with fuel oil without natural gas decontrol. The world recession has contributed to declining demand for all energy materials. While this has brought fuel oil prices tumbling down in recent months, gas prices have continued to climb.

Climbing gas prices can potentially result from large fixed costs facing utilities. As volume declines, these costs are spread over remaining customers. Somewhat unique to the U.S. gas industry, these fixed costs

FIGURE 5

ESTIMATED PRICE OF RESIDUAL FUEL OIL AND NATURAL GAS, 1960–1981



SOURCE:AMERICAN GAS ASSOCIATION AND U.S.D.O.E., STATE PHYSICAL UNIT DATA BASE, TABLE P-3

Table VII

Estimated Parity Prices of Natural Gas and No. 6 Residual Fuel Oil

	Gas Price ($/mmbtu) (dollars)	Fuel Oil Price[a] ($/mmbtu) (dollars)	Percent difference[b] in Natural Gas Price to Parity with Fuel Oil (percent)
		1981	
Illinois	3.66	5.17	41
Indiana	3.26	5.17	59
Iowa	3.45	5.17	50
Michigan	3.70	5.17	40
Wisconsin	4.19	5.17	23
U.S.	3.66	5.17	41
		August, 1982	
Illinois	4.46[c]	4.52	1
Indiana	3.97	4.52	14
Iowa	4.21	4.52	7
Michigan	4.51	4.52	--
Wisconsin	5.11	4.52	(-12)
U.S.	4.46	4.52	1

SOURCE: American Gas Association and the U.S. Dept. of Energy.

[a]Source; DOE/EIA-0035 (82/12). The conversion factor for No. 6 residual fuel oil is 6.287 MMBTU/Barrel.

This monthly average is reported from the source as national average retail residual fuel oil price, DOE/EIA-0035 (82/12). Again, it is assumed that residual fuel oil sells for the national average price in all states.

[b]This column assumes that each regional 1981 gas price climbed to parity to fuel oil, i.e. (column 2--column 1)/column 1.

[c]The August, 1982, average retail price to all customers is estimated as follows. All 1981 regional figures are expanded by national percent increase in average residential gas heating prices between the month of August, 1982, and the year 1981. Average residential heating prices are sampled by the Department of Commerce and reported in DOE/EIA-0035.

reflect "take-or-pay" contract provisions between pipelines and producers, forcing pipelines to purchase gas they cannot profitably sell. Also, long-term contracts lock buyers into rising allowable ceiling prices under NGPA. Market price adjustment to equilibrium under current arrangements appears to be slow.

Within the Seventh Federal Reserve District region, it is estimated that if natural gas prices had risen to parity with residual fuel oil in 1981, price jumps would have varied between 23 percent in Wisconsin to 59 percent in Indiana (Table VII). As a result of climbing gas prices and falling fuel oil prices, much smaller price jumps in natural gas would have had to occur by August, 1982, to achieve fuel oil parity. In fact, estimates reveal that some average gas prices in Wisconsin may already exceed parity with fuel oil. This portends large price increases to some residential consumers. As industrial customers switch to fuel oil, residential customers who have invested in gas heating furnaces may come to bear a greater portion of utility fixed costs.

Conclusion

Insofar as natural gas prices have already approached approximate parity with fuel oil within Seventh District states, accelerated decontrol of natural gas would have limited negative impact, on average, in this region. Of course, intra-regional variation in natural gas prices to consumers suggests that higher gas prices would accompany accelerated decontrol in some areas while lower gas prices would prevail in others. Moreover, prevention of general gas price increases under accelerated decontrol can only be accomplished with complementary state and federal regulation. At the federal level, damaging contract provisions entered into during the past decade, including take-or-pay provisions, must be amended to lessen pipeline costs of holding unsold gas.

At the state level, public utility commissions need to evaluate potential rate structures of public utilities that discount gas prices to certain categories of customers. Without such rate spreads in final gas prices or reductions in equity returns to utilities, residential customers may come to bear excessive final prices for natural gas as possible load loss increases the residential share of utility operating costs. This concern is critical to residents of Seventh District states, who largely depend on natural gas for home-heating purposes.

VIII. Conclusion

Past public policy actions attempted to balance the merits of controlling prices to certain classes of natural gas consumers against the merits of developing gas resources for the benefit of future customers and some present energy users. In the process, resulting market inefficiences in gas production cost the nation in overall national income. Recent NGPA regulations do not appear to have alleviated these costs to any significant degree and many analysts have argued that recent regulations have actually exacerbated production inefficiences. Although arguments of those supporting accelerated market decontrol were persuasive, the spectre of sudden gas price jumps caused by unexpected OPEC oil price increases contributed to delays in accelerating the price decontrol timetable.

Now, the events of worldwide recession, climbing gas price ceilings, and post-NGPA contract provisions that ratchet gas prices to highest allowable rates, have conspired to raise natural gas prices to approximate parity with residual fuel oil in both the region and the nation. With some caveats, immediate natural gas decontrol would not lift prices much beyond their current levels. As one caveat, some existing contract terms between transmission pipelines and wellhead producers stipulate that contract price on gas jump to the highest price being paid on similar gas at the time of decontrol. To the extent that these prices lie above equilibrium, pipelines would attempt to pass greater costs onto consumers, especially if producer-pipeline contract provisions included "take-or-pay" provisions on wellhead gas. Thus, accompanying Congressional amendment permitting renegotiation of current contract terms and other regulatory features of the NGPA would be necessary to forestall immediate and temporary price shocks arising from market decontrol. These same regulatory revisions must be considered regardless of any acceleration of the NGPA decontrol schedule so that the gas market can respond to declines in consumer demand.

State regulation of public utility pricing practices are also critical in preventing accelerated decontrol from resulting in higher price levels. State public utility commissions should consider rate spread structures that allow local gas utilities to discount prices to industrial customers. Such rate structures may be necessary to prevent price increases to residential customers that result from loss of utility volume. However, these rate structures can also raise prices to residential customers under some circumstances if they are not warranted or if they are not properly designed.

While the five Seventh District states are more dependent on natural gas than other states, Seventh District prices appear to equal the nation's average. In the absence of expected absolute or relative price rises, the region need not fear any added competitive disadvantage from decontrol. This is not to say that gas prices will not rise anywhere within Seventh District states. Some prices will rise and others will fall. Some firms with fragile profit positions may suffer from the moderate price increase that may ensue with accelerated decontrol. Others will benefit from lower prices that result from removal of take-or-pay provisions in contracts between pipelines and producers.

In contrast to the mid-1970s, supplies of natural gas to Seventh District firms and industries are plentiful. NGPA provisions increase available supply to interstate pipelines at the expense of intrastate pipelines serving gas-producing regions. Although this would seem to give a competitive advantage to the Midwest region in securing industrial supplies of gas, other features of the regulated gas market have left excess supplies in every region at current prices. Similarly, price ceilings favor interstate pipelines because these pipelines control relatively larger stocks of gas at controlled ceiling prices. Nevertheless, other market features have led to price levels in the Seventh District that do not differ from the national average.

At best, the Seventh District receives only short-term and small advantages over other regions from the overall structure of national gas policy. These benefits are not justified by the absolute damage caused by NGPA to the natural gas market and the nation's overall energy policy. By increasing the nation's productive efficiency in gas production, accelerated decontrol can aid the region by securing adequate future supplies at reasonable costs, increasing national income, and pressuring world energy markets into submission toward lower prices. In this regard, bringing rationality to national energy markets presents a modest but effective Midwest development policy in reviving this older industrial corridor.

FOOTNOTES

[1]See The Current State of the Natural Gas Market,Part I, DOE/EIA-0313, U.S.G.P.O., Washington, D.C., December, 1981, pg. 68.

[2]This history borrows heavily from The Current State of the Natural Gas Market, ibid.

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

[4]Ibid, DOE/EIA-0313, Pg. 10.

[5]See Appendix I for exact classifications and scheduled decontrol.

[6]Recent trends indicate that the actual figure will lie closer to 60 percent or more. See Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices, DOE/EIA-0303, August, 1981, for estimates under a variety of assumptions concerning the 1985 statutory and regulatory environment. For estimates of controlled quantities of natural gas through 1990, see The Current State of the Natural Gas Market, Part I, Table II.

[7]See The Current State of the Natural Gas Market, Part II, for an extensive discussion of recent contract terms and their implications.

For contract quantities covering post-NGPA wells, contracts covering approximately 59 percent of contract volume of post-NGPA wells have deregulation classes, ibid, p. IX.

[8]More recent trends are toward "market out" provisions in new gas contracts. Market-out provisions permit the buyer to cancel contracts if the gas delivery is not marketable at redetermined prices.

[9]These figures and those that follow may be found in the Monthly Energy Review, DOE-0035(83/01), January, 1983.

[10]Ibid. Part II, page. 41.

[11]On December 30, 1982, the FERC ruled that Columbia Gas Transmission Corp. must refund $100 million or more to customers residing in Northeastern states because the pipeline had purchased excessive quantities of high-priced gas while reducing purchases of cheaper gas.

[12]If a pipeline takes delivery of gas, it can promptly pass the costs along to consumers through a PGA. If not, the pipeline must recover these costs later in a rate increase. If a pipeline must choose between delivery of a low-priced and high-priced shipments covered by take-or-pay agreements, it may choose delivery of high-cost gas and suffer prepayments on the low-priced gas in order to preserve cash flow. Nevertheless, it is not certain that pipeline profits are always maximized by such a choice.

[13]See "Panhandle Eastern: A gas-shortage gamble is blowing up in its face", Business Week: May 24, 1982, pp. 106-110.

[14]Fifteen midwestern gas utilities, 28 Michigan industrial concerns, and prominent political leaders from Michigan and Ohio have petitioned FERC to rescind Panhandle's authorization to purchase Algerian LNG. Even if this petition proves successful, a loss of over $500 million in a Louisiana unloading facility will be borne by customers and possibly by shareholders. Consumer groups have also criticized FERC for approving transmission pipeline rate increases without close scrutiny of rate hike justification.

Insofar as these companies can easily pass along cost increases to local utilities via PGAs, it is contended that pipelines have little incentive to bargain for cheap wellhead prices or to economize on careful long-term supply planning. In response, FERC has stated that it will review future PGAs with closer scrutiny. This suggests that shareholders of pipeline utilities may come to bear greater risks from investment ventures and wellhead contract negotiations.

[15]For example, Northern National Gas Company of Omaha has asked the FERC for approval on price breaks to Iowa fertilizer (anhydrous ammonia) producers who face shutdowns in plant operations because of natural gas price hikes. See "High Natural Gas Prices Cripple Iowa Fertilizer Industry", Des Moines Register, October 10, 1982.

Among Seventh District states, fuel switching appears to be most severe in Wisconsin. Wisconsin Gas Company began charging prices higher than that of residual fuel oil on November 1, 1982. See "Feared shift to oil may be bad news for gas customers", Milwaukee Journal, Section 2, pg. 1., October 3, 1982.

[16]Ibid., DOE/EIA-0313, Pg. 66.

[17]See Paul W. MacAvoy, "The Time to Deregulate is NOW", New York Times, September 26, 1982, pg. 73.

[18]Numerous bills that placed new lids on wellhead prices were introduced into the post-election session of the 97th Congress. None were enacted into law.

[19]For example, see Robert A. Leone, "Natural Gas Decontrol and the Northeast Economy", paper presented at the Western Economic Association Meetings, July, 1982.

[20]See Kalt, J., Lee, H., and Leone, R.A., Natural Gas Decontrol: A Northeast Industrial Perspective, Energy and Environmental Policy, Harvard University, Cambridge, 1982.

The authors suggest that decontrol can only help the Northeast region by eliminating the energy cost advantage of other regions.

APPENDIX I

Natural Gas Policy Act Maximum Gas Ceiling Prices

Section of Act	Ceiling Description	January 1983 Ceiling Prices Per Million Btu	Date of Deregulation	Gas Category
102				New Natural Gas
	$1.75 as of 4/20/77 plus monthly inflation and inflation and escalation adjustments	$3.299	1/1/85	- New onshore wells at least 2.5 miles from nearest marker well or at least 1,000 feet deeper than any completion within 2.5 miles.
			1/1/85	- New onshore reservoirs
			1/1/85	- New Outer Continental Shelf (offshore) leases effective on or after 4/20/77.
			Not Deregulated	- Reservoirs discovered after 7/27/76 on old offshore (OCS) leases
103				New Onshore Production Wells
	$1.75 as of 4/20/77 plus monthly inflation adjustments	$2.722		- Wells with surface drilling starting after 2/19/77, satisfying applicable Federal or State well-spacing requirements and that are not within a proration unit
			[e] 1/1/85	- gas from wells deeper than 5,000 feet
			[e] 7/1/87	- gas from wells shallower than 5,000 feet

APPENDIX I (Continued)

Natural Gas Policy Act Maximum Gas Ceiling Prices

Section of Act	Ceiling Description	January 1983 Ceiling Prices Per Million Btu	Date of Deregulation	Gas Category
104	Gas Dedicated to Interstate Commerce Before the NGP Enactment Enactment (11/9/78)			
		$2.254	Not Deregulated	- Post-1974 gas
	the just and reasonable price as of 4/20/77 plus monthly inflation adjustment	[b]$1.908 [c]$1.459	Not Deregulated	- 1973-1974 Biennium gas
		[b]$ .539 [c]$ .424	Not Deregulated	- Flowing gas
		[b]$ .640 [c]$ .562	Not Dregulated	- Certain Permian Basin Gas
		[b]$0.640 [c]$0.539	Not Deregulated	- Certain Rocky Mountain Gas
		[b]$0.508 [c]$0.475	Not Deregulated	- Certain Appalachian Basin Gas
		[1]$0.280	Not Deregulated	- Minimum Rate Gas
105	Gas Sold Under Existing Intrastate Contracts			
	The lower of (a) the contract price under the contract terms as of 11/9/78 (b) the Section 102 price.		[f]1/1/85	- If contract price was less than $2.078 on 11/9/78
	The higher of (a) the contract price as of 11/9/78 plus monthly inflation adjustment and (b) the Section 102 price		[f]1/1/85	- If the contract price was more than $2.078 on 11/9/78

APPENDIX I (Continued)

Natural Gas Policy Act Maximum Gas Ceiling Prices

Section of Act	Ceiling Description	January 1983 Ceiling Prices Per Million Btu	Date of Deregulation	Gas Category
106	Sales of Gas Under "Rollover" Contracts			
	The higher of (a) the just and reasonable price as of the rollover date plus monthly inflation adjustment and (b) $.54 as of 4/77 plus monthly inflation adjustment[d].	[b]$ .837	Not Deregulated	- Interstate
	The higher of (a) the price paid under the expired contract as of the rollover date plus monthly inflation adjustment or (b) $1.00 as of 4/77 plus monthly inflation adjustment.[i,d]	[g]$1.553	[h]1/1/85	- Intrastate
107	High Cost Natural Gas[j]			
	Section 102 price or higher incentive price.	market price	11/1/79	- Gas produced from wells 15,000 feet or deeper drilled
	Otherwise applicable or higher incentive price	market price	11/1/79	- Gas produced from geopressured brine, coal seams and Devonian Shale
		$5.444	Not Deregulated	- Gas produced from tight sands
		Section 109 price	Not Deregulated	- Qualified production enhancement (only for 105 gas)

APPENDIX I (Continued)

Natural Gas Policy Act Maximum Gas Ceiling Prices

Section of Act	Ceiling Description	January 1983 Ceiling Prices Per Million Btu	Date of Deregulation	Gas Category
108		Stripper Well Natural Gas		
	\$2.09 as of 5/78 plus monthly inflation and escalation adjustments[k]	\$3.535	Not Deregulated	- Nonassociated natural gas produced at an average rate less than or equal to 60,000 cubic feet per day over a 90 day period
109		Other Categories of Natural Gas		
	\$1.45 as of 4/77 plus monthly inflation adjustment	\$2.254	Not Deregulated	- Prudhoe Bay gas - Gas not otherwise covered

[a]Beginning 1/1/85, gas from wells shallower than 5,000 feet receive a price midway between the price specified by this formula, and the 102 price.

[b]Small producers - independent producers not affiliated with a Class A natural gas pipeline company whose total jurisdiction sales on a national basis, including those by affiliated producers, do not exceed 10 Btu on a 14.73 pressure basis.

[c]Large producers - producers that are not small producers.

[d]Ceiling prices may be raised if just and reasonable.

[e]Interstate production from 103 wells on dedicated acreage committed on 4/20/77 is not deregulated.

[f]If contract price exceeds \$1.00 by 12/31/84, except a price established under an indefinite price escalator clause.

[g]Or expired contract price, whichever is higher.

[h]If the price is more than a dollar on 12/31/84.

[i]Natural gas production in which a state government or an Indian tribe has royalty or other interest is to receive the Section 102 price if it was not committed to interstate commerce on 11/8/78.

[j]High-cost gas provisions elective, i.e., do not apply if special tax provision are utilized.

[k]These prices have been escalated monthly, in addition to the inflation adjustment factor, by 3.5 percent annually. Starting April 1981 they escalated by 4 percent annually.

[l]Dollars per thousand cubic feet.

SOURCE: The Current State of the Natural Gas Market, Part I, EIA/DOE and U.S. Federal Energy Regulatory Commission, Docket No. RM80-53, (Issued Oct. 21, 1982).

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