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Natural gas policy and the Midwest

Justice's Merger Guidelines: Implications for 7th District banking

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Natural gas policy and the Midwest

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The complex structure of natural gas market regulations has brought mixed blessings to the Seventh District states of Illinois, Indiana, Iowa, Michigan, and Wisconsin. Federal price ceilings on the domestic production of gas held down consumer prices for natural gas, but only at the cost of occasional supply shortages that the Midwest experienced in the 1970s. These intermittent shortages in supply moved federal policy to major revision of gas market regulations. The Natural Gas Policy Act of 1978 (NGPA) secured greater gas supplies for interstate pipeline customers, including Seventh District residents, through favorable allocation directives and a schedule for decontrolling producer prices. The NGPA price decontrol schedule intended to gradually raise average gas prices to parity with petroleum by 1985. In this manner, decontrol would not subject gas consumers to price shocks. A regulatory middle way was fashioned between spurring energy production and holding consumer prices at bay.

Despite the intent of the NGPA to slowly phase up consumer gas prices, 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 primarily responsible for climbing domestic prices of natural gas. Nevertheless, certain regulatory features of the NGPA, coupled with the restrictive market regulation of an earlier era, accommodated these gas price increases by insulating producers and pipelines from declining market demand.

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. For these reasons, public interest has grown in amending our most recent gas policy to allow gas consumption and production to respond to market forces.

Participants in the natural gas market

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 agency administers allowable natural gas prices under the authority of the NGPA.

Transmission pipelines serve as an intermediary transport system between wellhead pro-

Figure 1
Principal agents in the domestic market for natural gas

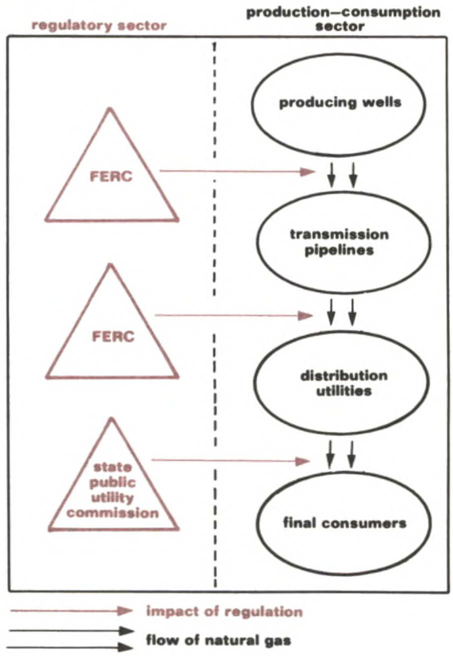

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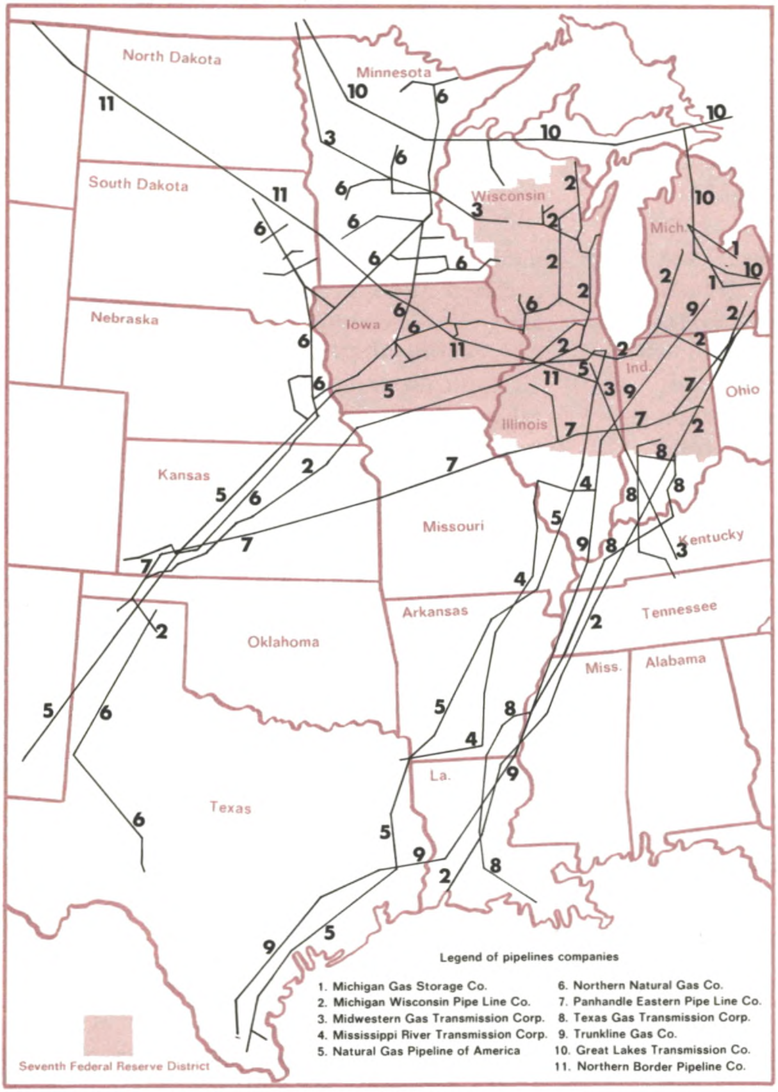
Figure 2
Primary transmission pipelines serving Seventh District states



Source: U.S. Department of Energy, Major Gas Pipelines, U.S. G.P.O., 1979.

ducers and distribution utilities (as well as some large commercial and industrial customers). The major portion of natural gas delivered to the Seventh District states is provided via 11 transmission pipeline companies. In the Midwest, the bulk of natural gas comes from the Southwestern states of Texas, Oklahoma, and Louisiana (Figure 2). Lesser volumes of natural gas originate from local wells, Appalachian gas fields, and foreign countries (largely Canada and Mexico).

Sales of natural gas by transmission pipeline companies are also regulated by the FERC. Increases of 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 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.

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 1). 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.

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 are close to the national average. Consuming only 20.5 percent

Table 1

Share of total energy consumption accommodated by natural gas by sector, 1980 (1970)

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

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

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 have a higher proportion of residences with gas heating than the nation's average (Table 2). In this regard, Illinois ranks first in the nation and Michigan, sixth.

Table 2

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.*

Regions vary not only in their relative dependence on natural gas but also in their absolute consumption of energy and natural gas. Seventh District residents consumed about 91,000 cubic feet of gas per capita in 1980, exceeding national per capita consumption by about 3,000 cubic feet (Table 3). The Seventh District con-

Table 3

Per capita natural gas consumption and production, 1980

	Consumption		Production	
	Thousand cubic feet	Percent change from 1970	Thousand cubic feet	Percent change from 1970
Illinois	95.4	−10	.1	− 68
Indiana	89.1	−15	.1	200
Iowa	92.5	−25	0.0	0
Michigan	93.4	3	17.1	291
Wisconsin	74.8	− 2	0.0	0
District states	90.7	− 9	4.8	254
United States	87.8	−16	90.0	− 17

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

sumes much more natural gas than it produces. Michigan produces the only significant amounts of natural gas among District states. That state produced over 17 thousand cubic feet (mcf) of gas per capita in 1980, an increase of almost 300 percent from 1970.

Natural gas prices in the Seventh District

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 4). While the nation's gas prices climbed at a compound 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 Michigan's and Wisconsin's average gas price remained above the national average in 1981. 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.

In the period preceding NGPA, 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.

Federal government regulation: a synopsis

The development of the seamless welded pipe in the 1920s ushered in the era of natural gas and natural gas delivery systems. Because 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.

In 1954, the United States 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. In essence, pro-

Table 4

Gas utility industry average prices (all customers) 1970-1981 ($/million btus)

	1970	1978	1979	1980	1981	Compound annual rate of increase 1970-78 (percent)	1978-81 (percent)	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
United States	.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 Fahrenheit.

ducers who chose to sell natural gas to interstate pipelines became public utilities while producers who sold to the intrastate pipelines market remained largely unregulated by the federal government.

As a result of this court decision, producers became reluctant to develop and sell gas to interstate pipelines. Regulated prices to interstate gas producers began to lag significantly behind the market-determined price of gas sold to intrastate pipelines because FPC price administration proved to be a slow and costly process. The pricing differential encouraged drilling in areas served by intrastate pipelines at the expense of areas served by interstate pipelines.

Two natural gas markets thus 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 had lower relative prices than the intrastate market but also dwindling gas supplies. By the winter of 1972, shortages were occurring 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 imbalance in the natural gas market. During 1978 several legislative enactments markedly altered the regulatory environment. The most significant legislative reform was the 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.

The NGPA alleviated supply shortages in interstate pipelines by several methods. First, NGPA capped intrastate gas prices, thus diverting a greater available supply to interstate markets. In addition, gas production from federal land on the outer continental shelf could 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 and in their price decontrol dates, in 1985 and 1987 (Table 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. Ceilings on "new gas," gas from new wells and gas from those wells placed in production since 1977, rise at an additional four percent per year. Price ceilings for most new gas are to be eliminated on January 1, 1985. Some classes of older 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.

In addition to the wellhead ceilings and a price decontrol schedule, the NGPA set forth a scheme of incremental pricing that insures that industrial users of natural gas pay prices for natural gas that subsidize commercial and residential customers. Incremental pricing allocates a portion of the costs of certain high-cost gas to certain industrial uses, large industrial boilers in particular.

Concurrent with NGPA, the Powerplant and Industrial Fuel Use Act of 1978 (FUA) altered the demand for natural gas. The Act 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

Table 5

Scheduled decontrol dates of NGPA gas categories*

NGPA classification	Description	Date of decontrol
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 decontrolled
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 decontrolled
105, sold under existing intrastate contracts	• all types	1/1/85
		1/1/85
106, sales under "rollover" contracts	• interstate	not decontrolled
	• 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 decontrolled
108, stripper wells	• produced at rate less than 60,000 ft^3/day	not decontrolled
109, other	• Prudhoe Bay and other	not decontrolled
Imported gas	• price set by approval of the FERC and the Economic Regulatory Administration	not decontrolled

*In general, wells qualifying under more than one category are eligible for the price ceiling and decontrol status of choice.

increases in the short term to protect certain classes of customers. Although price 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.

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 consumption of natural gas, 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. One type of escalator clause, the deregulation provision, causes particular alarm in discussion over price hikes accompanying partial decontrol. Contracts covering approximately 59 percent of contract volume of post NGPA wells have deregulation clauses. In the event of price decontrol, these provisions lift wellhead prices of contracted gas to free market rates, or to indefinite levels such as 110 percent of the price of residual fuel oil, or the average of the two or three highest prices being paid in the vicinity of the gas well.

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 were rapidly rising. These rapid price hikes were accompanied by falling energy consumption, falling prices for substitute fuels, and falling natural gas consumption.

The current gas market

The recent recession 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. 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 may have influenced gas consumption. Moreover, rising prices themselves encourage conservation by gas customers.

Despite this 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 and imported 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 the 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, further 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 continuing shortages, pipelines included escalator clauses, take-or-pay clauses, and other onerous terms in contracts with wellhead producers. These contract clauses have partly protected some producers from unanticipated declines in final market demand, much to the detriment of transmission pipelines, utilities, and especially final consumers.

"Take-or-pay" provisions insure that pipelines pay above-market prices in periods of slack demand. These provisions require pipelines to pay for contracted volumes of gas on a specified schedule regardless of whether pipelines can market 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.

While take-or-pay contract features have partly protected some wellhead producers 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 to pipelines via PGAs without major delays. 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 upsetting 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 that 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 further raised the average price of gas that pipelines sell to distribution utilities.[1]

Pipelines are thought to decrease their takes of low-cost gas during periods of slack demand because PGAs allow a price pass-through only for wellhead gas that is sold by the pipeline to a distributor or other customer. Pipelines may elect to sell expensive wellhead gas to their customers and make pre-payments to producers on their takes of low-priced gas in order to increase revenues via PGA price compensation.

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

[1]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. More recently, some pipelines, including Columbia, are attempting to abrogate purchase contracts with producers. Similar actions are placing downward pressure on prices and revenues of wellhead producers.

distributors. Unlike petroleum pipelines, natural gas transmission pipelines are not considered common carriers. Hence, gas distributors 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 transmission pipelines pass along price increases in wellhead gas. State public utility commissions usually maintain their own versions of PGAs to reflect ongoing price increases resulting from increased costs of gas purchases.

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 have been met by consumer resistance in both the market and political arena. For example, voters in Michigan recently passed a ballot issue to abolish automatic fuel and gas adjustment clauses and 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 distributors 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 FERC.

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 demand swings force utilities to spread the fixed portion of delivery costs (and take-or-pay provisions) over fewer customers, thus further raising the delivered price of gas. 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 prevent switching from gas to alternative fuels such as fuel oil or to prevent actual plant closings. These discounts are often unpopular with the general public. But under certain conditions these discounts can limit price increases to all gas customers by spreading the high fixed overhead costs of utilities across a greater volume.

Issues in the current policy debate

Recent price increases and speculation over price jumps accompanying 1985 decontrol have greatly increased public discussion surrounding gas policies. In addition to concern over the 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 who 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. This 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.

A second inefficiency stems 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. The NGPA alleviates supply shortages in interstate pipelines by favoring interstate pipelines over intrastate lines. Advocates of accelerated decontrol argue that these inefficiencies should be removed to promote national economic growth and development.[2]

Other advocates of accelerated decontrol point out that a potential "fly-up" of gas prices in 1985 and beyond, caused by the current decontrol schedule, 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, some analysts maintain that accelerated decontrol will moderate future gas price levels by bringing rational production incentives to producers. For example, some analysts forecast 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.

Although some observers have advocated an acceleration of the NGPA schedule since its inception, decontrol has recently gained momentum from the current market conditions of slack demand and rising price. 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 an immediate price increase to consumers. To accomplish this end, complementary legislation, such as amendment of take-or-pay contracts and PGA clause procedures, must accompany accelerated decontrol.

At the same time that market inefficiencies have heightened interest in accelerating 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. Views favoring continued controls are largely based on the belief that gas prices would indeed rise under accelerated decontrol, much as prices have risen in the post-NGPA era. It is argued that consumers have suffered enough from recent gas price jumps. The distress of presently climbing residential and commercial fuel bills leads to arguments that decontrol of gas await a future date, a date that is approached by a long transition of gradually rising prices.

The impact of accelerated decontrol on gas prices in the Seventh District

Despite difficulties in untangling the complex web of regulatory influences, short-term estimates of market prices for gas under accelerated price decontrol can be tied to the market prices of substitute fuel products, particularly residual fuel oil. Such estimates are based on the assumption that (1) natural gas and fuel oil are ready substitutes on a large scale; (2) supplies of neither fuel are sufficient to back the use of the competing fuel out of the market; and (3) complementary legislation accompanies the lifting of NGPA price ceilings, allowing market bidding for the use of these fuels. In this environment, natural gas and residual fuel oil are substituted for each other until price parity is attained. At the point of price parity, both fuels are consumed with a large segment of energy consumers indifferent between these fuels.

These assumptions are supported by the use of both gas and fuel oil as boiler fuels in U.S. energy markets. Industrial boilers are estimated to have consumed approximately one-third of the energy used in manufacturing in 1976. Natural gas was the primary industrial boiler fuel, with more than a 40 percent share of the total. In addition many boilers can switch fuel consumption between oil and gas at moderate cost. One estimate indicates that 53 percent of large-boiler fuel use in 1979 occurred in boilers capable of switching between fuel oil and natural gas use at the turn of a valve.

Insofar as petroleum prices have been very erratic in recent years, forecasts of energy prices become increasingly unreliable further into the future. For this reason, this type of gas price estimate must be limited to near-term approximations of gas prices under accelerated decontrol. Among Seventh District states, it is estimated that if natural gas had risen to parity with residual fuel oil in August, 1982, price jumps in

[2]Although regional gas allocation is 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.

District states would have ranged from 1 percent in Illinois to 14 percent in Indiana (Table 6). In contrast, the price of natural gas in Wisconsin appears to have exceeded parity with fuel oil by approximately 12 percent.

Table 6

Relationship of natural gas and No. 6 residual fuel oil prices, August 1982

	Gas price	Fuel oil price*	Difference
	($/mmbtu)		(percent)
Illinois	4.46	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)
United States	4.46	4.52	1

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

*National average price is assumed for each state.

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 accelerated decontrol would produce higher gas prices to some homes and factories while other regional gas prices would decline. Moreover, prevention of general gas price increases under accelerated decontrol can only be accomplished with complementary state and federal legislation.

Whether or not the federal government moves to accelerate the NGPA schedule of wellhead gas, 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 amending PGA procedures.

Both federal and state governments 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, state regulators may decide to lower the rate of equity return to pipelines and distributors rather than discount prices to large industrial customers.

Justice's Merger Guidelines: Implications for 7th District banking

Diana Alamprese Fortier and John J. Di Clemente

A considerable amount of attention has been given the Department of Justice Merger Guidelines that were issued in June of 1982. One of the major areas of interest has been whether these Guidelines are more or less restrictive than the earlier (1968) version.[1]

The purpose of this article is to analyze and compare the 1968 Department of Justice Merger Guidelines with the 1982 version to determine whether the new Guidelines are more or less stringent than the 1968 Guidelines with respect to horizontal mergers within the context of the banking industry.[2]

First, the structure-conduct-performance paradigm and traditional measures of market concentration are reviewed. Second, the 1968 and 1982 Guidelines are presented and applied to a set of hypothetical bank mergers in local banking markets in the five states comprising the Seventh Federal Reserve District. Finally, an evaluation of the test results and their implications for future merger policy are set forth.

Why Guidelines?

The enforcement policy of the Department of Justice (the Department), as reflected in the 1968 Guidelines, had several interrelated objectives: (1) to prevent the elimination of a significant independent competitor in a market; (2) to prevent any one firm or group of firms from obtaining a dominant position in a market; (3) to prevent a significant increase in market concentration; and (4) to preserve the possibility of future deconcentration of relatively concentrated markets. The 1982 Guidelines state the objective more simply: to prohibit mergers that create or enhance market power or facilitate the exercise of such power.

The 1968 Guidelines, in effect until June 14, 1982, were to be reviewed and possibly amended periodically to reflect any significant changes in standards or policy of the Department. But although Department policy had changed over the past 14 years of merger enforcement, no amendments or formal changes were made in the 1968 Guidelines. As a result, as William F. Baxter, head of the Antitrust Division of the Department, stated in August 1981, "the [1968] Guidelines are now substantially at variance with the state of the law and with the Department's actual enforcement practices."[3]

The issuance of the 1982 Guidelines reflects the recent trend in merger decisions by the courts, enforcement policies of the Department, and recent economic research. As in the case of the 1968 Guidelines, the 1982 Guidelines attempt to reduce the uncertainty of the public, the legal profession, business, and government concerning the Department's antitrust policies. The underlying emphasis of the 1982 Guidelines is that, contrary to popular belief, not every merger is anticompetitive. Mergers may have a neutral or procompetitive effect by promoting capital investment and the reorganization and redevelopment of existing productive assets.

The Board of Governors of the Federal Reserve System (the Board) has generally incorporated the 1968 Guidelines into its analysis of commercial bank and bank holding company acquisitions and mergers pursuant to the Bank

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[1]For conflicting points of view see, for example, Joe Sims and William Blumenthal, "New Merger Guidelines Provide No Real Surprises," *Legal Times of Washington*, June 21, 1982, p. 17; Gordon Spivack, "New Merger Guidelines Are Substantially Different," *Legal Times of Washington*, August 2, 1982, p. 38; and Eleanor M. Fox, "The new merger guidelines—a blueprint for microeconomic analysis," *The Antitrust Bulletin*, Fall 1982, pp. 519-591.

[2]Although the 1968 and 1982 Guidelines also deal with vertical and conglomerate mergers, this article narrows the emphasis to horizontal mergers in the banking industry.

[3]Testimony of William F. Baxter before the Subcommittee on Monopolies and Commercial Law, House Committee on the Judiciary, August 26, 1981.

Holding Company Act and the Bank Merger Act.[4] It is also likely that the Board will consider the 1982 Guidelines as a policy guide to horizontal merger enforcement.

The structure-conduct-performance paradigm

Economic theory postulates a relationship between market structure and the conduct and performance of firms within the market. Premised upon the existence of such a relationship, antitrust laws have been designed to detect and prevent undue concentrations of market power and trends toward cartelization and monopolization.

Under Section 7 of the Clayton Act, the antitrust authorities in the U.S. are mandated to challenge any acquisition " . . . where in any line of commerce, in any section of the country, the effect of such acquisition may be substantially to lessen competition, or to tend to create a monopoly."[5] Under this mandate the relevant product market needs to be determined. Based on this determination, a relevant geographic area must be carved out in which the firms in question compete. Finally, an assessment must be rendered as to whether the merger would substantially reduce competition if consummated.

Under both Guidelines the enforcement of the antitrust laws relies primarily on structural criteria, focusing on market power, market structure, and the likely effect of mergers on these factors. The Guidelines may thus be viewed as indicia for assessing the probability of tacit and explicit collusion.

Market structure refers to the number and size distribution of firms within a given market. Market power is a murky term that suggests the power of each seller to set its own prices without losing all or substantially all its customers, even if prices are set above perfectly competitive levels. This power is believed to be derived from a substantial market share and has been, and continues to be, the target of advocates of competition.

The principal test of competition under both the 1968 Guidelines and the 1982 Guidelines is based not upon the actual conduct of firms in a market but rather upon the likely effect implied. Both Guidelines are premised on the concept that a probability of noncompetitive pricing can be inferred from the number and size distribution of the firms in the market. As Bain notes, one may envisage a three-stage sequence of causation from market structure to market conduct and resulting market performance. That is, structure is systematically associated with or determines what conduct will be; conduct determines what performance will be; and, thus, structure is associated systematically with performance.[6]

Inferring market conduct from market structure begs the question as to how competitively markets behave in fact. The traditional structure-conduct-performance approach relies, instead, on the assumption that highly concentrated markets, markets in which few relatively large firms compete, are noncompetitive.

Termed oligopolistic markets, such markets may or may not be acting competitively. Posner notes that " . . . tacit collusion or noncompetitive pricing is not inherent in an oligopolistic market structure but, like conventional cartelizing, requires additional, voluntary behavior by the sellers."[7]

Whether collusive pricing is successful requires that firms in oligopolistic markets weigh the potential gains against the costs of collusion. The costs, as noted by Posner, are of two types: (1) costs of arriving at a common price above the competitive price level and (2) costs of preventing cheating on the agreed-upon price by members of the group.[8] If the potential gains

[4]See for example: *Sun Banks of Florida Inc., Federal Reserve Bulletin*, vol. 68 (June 1982) p. 374 and *Policy Statement of the Board of Governors of the Federal Reserve System for Assessing Competitive Factors Under the Bank Merger Act and Bank Holding Company Act*, 47 *Federal Register* 9017 (March 3, 1982).

[5]Clayton Act, Section 7 amended, 15 U.S.C., Section 18.

[6]Joe S. Bain, *Industrial Organization*, John Wiley & Sons Inc. (1959), p. 295.

[7]Richard A. Posner, "Oligopoly and The Antitrust Laws: A Suggested Approach", *Stanford Law Review*, June 1969, p. 1578.

[8]Richard A. Posner, *Antitrust Law: An Economic Perspective*, University of Chicago Press (1976), pp. 51-2.

from collusion are not sufficient to outweigh the costs involved, collusion would not be attempted.[9]

While it is agreed that competition does not disappear as markets become more highly concentrated, it is also recognized that highly concentrated markets are conducive to collusion and noncompetitive pricing. Posner notes that "Some degree of concentration thus appears to be a necessary condition of successful collusion . . ."[10] Also, in markets characterized by only a few firms, or only a few firms of great relative size, the firms must realize their policies affect one another. That is, the firms recognize their interdependence and may develop a common price policy without express collaboration, "just as an experienced string quartet learns to play as a unit."[11] While market concentration does not compel collusive pricing policies, it facilitates their implementation.

Those who criticize the use of market structure as the test of competition prefer to focus on the pricing policies and behavior of firms thought to be in an oligopolistic market. One problem with this approach is determining methods of identifying and measuring market conduct that is noncompetitive. Bain notes that " . . . actual patterns of market conduct cannot be fully enough measured and described to permit empirical establishment of meaningful associations between market conduct and performance, or between market conduct and structure. It is thus expedient to test directly for net associations of market structure to market performance, leaving the detailed character of the implied linkage of conduct substantially unascertained."[12] Thus, expediency rules the day under both Guidelines.

It should be emphasized that conclusions regarding market conduct inferred from market structure are rebuttable. Under the antitrust laws, evidence of high concentration establishes a *prima facie* case of noncompetitive market behavior. This presumption may be overcome by a showing of actual competitive market behavior.[13] A finding of high concentration in a market in which two competing firms propose to merge is only the beginning of the antitrust analysis.

Measures of concentration

Economic theory and legal precedent have established that highly concentrated markets are deserving of special scrutiny under the antitrust laws. But how is concentration to be measured? On this point the 1968 and 1982 Guidelines differ.

The concentration ratio as a measure of overall market concentration is the keystone to the 1968 Guidelines. Under the 1968 Guidelines market structure is classified as either "highly concentrated" or "less highly concentrated", depending on the value of the four-firm concentration ratio.

Within each concentration classification the 1968 Guidelines specify market shares of merging firms which would violate the Guidelines. Permissible market shares are higher in less highly concentrated markets. Mergers in markets that are characterized by a trend toward concentration are the subject of special antitrust concern under the 1968 Guidelines (see Table 1).

The 1982 Guidelines break ground with the old Guidelines by utilizing the Herfindahl-Hirschman Index (HHI) as a summary measure of market concentration. As in the 1968 Guidelines, market concentration classifications are developed—"highly concentrated", "moderately concentrated", and "unconcentrated". However, under the 1982 Guidelines the level of concentration in a market is based on the value of the *post-merger* HHI.[14]

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[9]For an account of the feasibility of collusion see George Stigler, "A Theory of Oligopoly, *Journal of Political Economy*, February 1964, p. 229, and for conditions conducive to collusion see Posner, *Antitrust Law: An Economic Perspective*, *op. cit.*, pp. 53-66.

[10]Posner, *Antitrust Law: An Economic Perspective*, *op. cit.*, p. 52.

[11]George J. Stigler, *The Theory of Price*, The Macmillan Co. (1954), p. 229.

[12]Bain, *op. cit.*, p. 295.

[13]*U.S.* v. *Marine Bancorporation*, 418 U.S. 602, 631-632 (1974).

[14]The post-merger HHI is calculated by adding the change in the HHI resulting from the merger to the pre-merger HHI. In short, the change in the HHI is equal to twice the product of the market shares of the merging firms. Given a market with a pre-merger HHI of 1600, if a firm with a 20 percent market share merges with a firm with a 3 percent market share the change in the HHI would be $(20 \times 3) \times 2 = 120$ and the resulting HHI would be 1720.

Table 1

1968 Department of Justice Horizontal Merger Guidelines

Challengeable market shares*

	Acquiring firm	Acquired firm
Highly concentrated market:	4%	4% or more
4-firm concentration ratio of	10%	2% or more
75% or more	15% or more	1% or more
Less highly concentrated market:	4%	5% or more
4-firm concentration ratio	10%	4% or more
less than 75%	15%	3% or more
	20%	2% or more
	25% or more	1% or more
Market with trend toward concentration	Acquisition of a firm with a market share of 2% or more is subjected to challenge. A trend toward concentration is present when the aggregate market share of any grouping of the largest firms in the market from the two largest to the eight largest has increased by approximately seven percent or more from any year five to ten years prior to the merger up to the time of the merger.**	

*Percentages not listed in the following tables should be interpolated proportionately to the percentages that are shown.

**See Department of Justice Merger Guidelines, May 30, 1968, p. 10.

The likelihood of a challenge to a merger within each concentration class depends upon the amount of increase in the HHI resulting from the merger. Other factors being equal, the permitted amount of increase in concentration resulting from a merger varies inversely with the post-merger level of market concentration (see Table 2).

Comparison of the 1968 and 1982 Guidelines

The 1982 Guidelines present detailed procedures for establishing the relevant product and geographic market. The determination of the provisional product and geographic market under the 1982 Guidelines is essentially the 1968 product and geographic market analysis based on product and geographic substitutability at prevailing prices. The 1982 Guidelines necessarily broaden the market definition by considering the dynamic element of changes in demand and supply patterns resulting from a given hypothetical change in price. That is, the provisional product and geographic market is expanded to take into account product and geographic substitution in response to a small but significant and nontransitory increase in price. (As a first approximation the Department will analyze the change in demand and supply patterns over one year in response to a five percent price increase.)

The basic difference between the concentration ratio and the HHI as measures of market concentration makes a precise comparison of the 1968 and 1982 Guidelines difficult. Nonetheless, a comparison can be made by converting the market shares of the 1968 Guidelines into an HHI.[15]

The 1982 Guidelines broaden the range of permissible market share combinations within each concentration class. Moreover, the 1982 Guidelines create a "safe harbor" for mergers in that any merger in an unconcentrated market is likely to go unchallenged. The "trend toward concentration" clause of the 1968 Guidelines has been eliminated. Thus, the 1982 Guidelines reflect a possible weakening in the importance

[15]See Table 3: "Comparison of the 1968 and the 1982 Horizontal Merger Guidelines", which suggest that under the 1982 Guidelines there will be a relaxation of merger enforcement.

Table 2

1982 Department of Justice Horizontal Merger Guidelines

Post-merger market concentration	Level of Herfindahl-Hirschman Index	Post-merger change in Herfindahl-Hirschman Index and likelihood of a challenged merger
Highly concentrated	Greater than 1800	Greater than 100—likely to be challenged
		50 to 100—depends on other factors*
		Less than 50—unlikely to be challenged
Moderately concentrated	1000 to 1800	Greater than 100—likely to be challenged; other factors considered*
		Less than or equal to 100—unlikely to be challenged
Unconcentrated	Less than 1000	Any increase—unlikely to be challenged

Lead firm proviso

The lead firm proviso states that a merger is likely to be challenged if the merger is between the lead firm and a firm with a market share of one percent or more provided that the lead firm has a market share of 35 percent or more and is approximately twice the size of the second largest firm in the market.

*In addition to the post-merger concentration of the market and the size of the resulting increase in concentration, the Department will consider the presence of the following factors in deciding whether to challenge a merger: ease of entry; the nature of the product and its terms of sale; market information about specific transactions; buyer market characteritstics; conduct of firms in the market; and market performance. (For a detailed explanation of these factors see Sections III (B) and III(C) of the 1982 Department of Justice Merger Guidelines.)

of arresting anticompetitive tendencies in their early stages.[16]

The new Guidelines establish special criteria to identify markets with individual dominant sellers as distinguished from markets in which the exercise of market power is carried out collectively by several firms (see Table 2). Referred to as the "lead firm proviso," their objective is to prevent any one firm from obtaining a dominant position in a market. Although no specific lead firm criteria are outlined in the old Guidelines, the prohibited market shares stated suggest an implicit lead firm standard. Moreover, the old Guidelines are more stringent in that, regardless of the market share of the second largest firm, a merger between firms with market shares of 25 percent and 1 percent would be challengeable even in a less highly concentrated market.

In the analysis of certain merger defenses the old and the new Guidelines do not differ. Neither set of Guidelines gives much credibility to the efficiency and economies of scale argument as a mitigating factor in an otherwise challengeable merger. To qualify as a mitigating factor, the merger must produce substantial cost

[16] *U.S.* v. *The Philadelphia National Bank*, 374 U.S. 321, 362 (1963).

Table 3

Comparison of the 1968 and the 1982 Horizontal Merger Guidelines*

1968 Guidelines			1982 Guidelines
Challengeable Market Shares			
Highly concentrated market			Highly concentrated market
Acquiring firm	Acquired firm	Converted to change in Herfindahl-Hirschman Index	Post-merger change in Herfindahl-Hirschman Index and likelihood of a challenged merger
4%	4% or more	(4 × 4) × 2 = 32	Greater than 100—likely to be challenged
10% or more	2% or more	(10 × 2) × 2 = 40	50 to 100—depends on other factors
15% or more	1% or more	(15 × 1) × 2 = 30	Less than 50—unlikely to be challenged
Less highly concentrated market			Moderately concentrated market
4%	5% or more	(4 × 5) × 2 = 40	Greater than 100— likely to be challenged; other factors considered
10%	4% or more	(10 × 4) × 2 = 80	
15%	3% or more	(15 × 3) × 2 = 90	
20%	2% or more	(20 × 2) × 2 = 80	Less than or equal to 100— unlikely to be challenged
25%	1% or more	(25 × 1) × 2 = 50	

*NOTE: Provided there is no change in the concentration classification from the old to the new Guidelines, none of the mergers listed as being challengeable under the 1968 Guidelines are likely to be challenged under the 1982 Guidelines. For markets classified as unconcentrated under the 1982 Guidelines, any increase in the Herfindahl-Hirschman Index is permissible. Thus a more lenient standard is reflected under the new Guidelines.

savings not attainable by other means. Nor do the 1968 or 1982 Guidelines allow approval of an otherwise significantly anticompetitive merger under the failing firm defense without strict scrutiny.

An effective failing firm defense requires that three conditions be satisfied. First, the allegedly failing firm must demonstrate an inability to meet financial obligations in the near future. Secondly, the firm must be unable to reorganize successfully under Chapter XI of the Bankruptcy Act. Finally, the firm must have been unable to obtain less anticompetitive offers of acquisition.

As with the 1968 Guidelines, the 1982 Guidelines consider nonstructural factors in the decision whether to challenge a proposed transaction. The old Guidelines apply nonstructural factors more as an additional standard for an otherwise unchallengeable merger based on structural criteria. The new Guidelines use nonstructural factors more as discriminating factors in judging an otherwise close case as determined solely by structural factors.

For a given level of market concentration, the 1982 Guidelines take into consideration "other factors" which would affect the probability of successful (profitable) tacit and explicit collusion. The most important of these "other factors" is the ease of entry. If, after taking into account market concentration, market shares, and ease of entry, the decision to challenge a merger is still close, the following factors will be considered: the nature of the product and its terms of sale; market information about specific transactions; buyer market characteristics; the conduct of firms in the market; and market performance. These factors are judged as to whether they enhance or facilitate the ability of firms in a particular market to exercise market power[17] (see Table 2).

Methodology

To assess the relative stringency of the 1968 and the 1982 Guidelines with respect to the banking industry, a series of hypothetical horizontal mergers are proposed in rural and metropolitan banking markets.

A necessary predicate to the analysis of any merger is the determination of the relevant market, both in terms of its product dimension ("line of commerce") and its geographic dimension ("section of the country"). It is assumed for the purpose of this analysis that commercial banking constitutes a distinct line of commerce.[18] It is further assumed that relevant geographic markets may be approximated by Standard Metropolitan Statistical Areas (SMSAs) and nonSMSA county boundaries.

While it is clear that political boundaries per se are not enough to establish markets in bank merger analysis,[19] the purpose of this article is to render an overall impression regarding the relative stringency of the 1982 Guidelines vis-à-vis the 1968 Guidelines. This being the case, greater precision in geographic market delineation is not warranted. The relevant geographic markets utilized in the present study consist of 296 rural markets (nonSMSA counties) and 45 metropolitan markets (SMSAs) located in the five states of the Seventh Federal Reserve District.[20]

Hypothetical mergers

The following hypothetical mergers are used to assess the relative stringency of the 1968 and 1982 Guidelines:

- (Case I) the merger of the two largest banking organizations;
- (Case II) the merger of the two smallest banking organizations;
- (Case III) the merger of the third and fourth largest banking organizations; and
- (Case IV) the merger of the fourth and fifth largest banking organizations.[21]

For each of the 341 banking markets, the proposed hypothetical mergers are judged as to their permissibility under the 1968 and 1982 Guidelines. The four-firm concentration ratio and HHI for each market are based on the total domestic deposits held by commercial banking organizations therein.[22]

The number and percentage of mergers in contravention of each set of Guidelines are presented in Tables 4 and 5. The results indicate that, based solely on structural criteria, the 1982 Guidelines when applied to bank mergers in the Seventh District reflect a less stringent horizontal merger policy than did the 1968 Guidelines. The following analysis presents the test results on a case-by-case basis for rural banking markets and metropolitan banking markets.

Mergers in rural markets

The analysis of 902 hypothetical mergers in 296 rural (nonSMSA) banking markets demonstrates that the 1982 Guidelines are somewhat less restrictive than the 1968 Guidelines. In each of the four cases more mergers are permitted under the 1982 than under the 1968 Guidelines.

- Case I mergers exhibit the least variance between the 1968 and 1982 Guidelines. All of the proposed Case I mergers are challengeable under the 1968 Guidelines while 99.0 percent are subject to challenge under the 1982 Guidelines.

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[17]See Section III C of the 1982 Department of Justice Merger Guidelines.

[18]See for example: *U.S.* v. *The Philadelphia National Bank* 374 U.S. 321 (1963); *U.S.* v.*Phillipsburg National Bank & Trust Co.* 399 U.S. 350 (1970); *United Bank Corporation of New York, Federal Reserve Bulletin*, vol. 67 (April 1981) p. 358; and *Hartford National Corporation, Federal Reserve Bulletin*, vol. 68 (April 1982) p. 242.

[19]*U.S.* v. *Connecticut National Bank* 418 U.S. 656, 670 (1974).

[20]As of June 30, 1980, there were 333 nonSMSA counties in the five subject states. In this study, markets having only one or two banking organizations are eliminated. Thus, 296 nonSMSA markets are used. As of the same date, 45 SMSAs were located completely within the boundaries of the five states.

[21]In markets with fewer than four banking organizations, Cases III and IV are not analyzed.

[22]Deposit and structure data are as of June 30, 1980.

Table 4

Horizontal mergers in rural markets

State	Markets	Challengeable under old (1968) guidelines	Challengeable under new (1982) guidelines	Difference: old (1968) minus new (1982)
	(number)	*(number, percent)*	*(number, percent)*	*(number)*
CASE I				
(Largest and second largest)				
Illinois	72	72(100)	72(100)	0
Indiana	48	48(100)	48(100)	0
Iowa	86	86(100)	86(100)	0
Michigan	43	43(100)	43(100)	0
Wisconsin	47	47(100)	44(94.0)	3
All 5 states	296	296(100)	293(99.0)	3
CASE II				
(Smallest and next smallest)				
Illinois	72	33(45.8)	28(38.9)	5
Indiana	48	43(89.6)	43(89.6)	0
Iowa	86	54(62.8)	43(50.0)	11
Michigan	43	26(60.5)	21(48.8)	5
Wisconsin	47	21(44.7)	20(42.6)	1
All 5 states	296	177(59.8)	155(52.4)	22
CASE III				
(Third largest and fourth largest)				
Illinois	49	49(100)	47(95.9)	2
Indiana	8	8(100)	8(100)	0
Iowa	57	57(100)	57(100)	0
Michigan	13	13(100)	13(100)	0
Wisconsin	28	28(100)	25(89.3)	3
All 5 states	155	155(100)	150(96.8)	5
CASE IV				
(Fourth largest and fifth largest)				
Illinois	49	49(100)	43(87.8)	6
Indiana	8	7(87.5)	7(87.5)	0
Iowa	57	56(98.2)	55(96.5)	1
Michigan	13	10(77.0)	9(69.2)	1
Wisconsin	28	28(100)	25(89.3)	3
All 5 states	155	150(96.8)	139(89.7)	11

- The challenge rate for Case II mergers is, not surprisingly, lower than the challenge rate for the other three merger cases under both sets of Guidelines. Under the 1968 and 1982 Guidelines 59.5 percent and 52.0 percent of Case II mergers, respectively, are subject to challenge.
- All Case III mergers would be objectionable according to the 1968 Guidelines whereas 96.8 percent of such mergers would be challenged under the 1982 Guidelines.
- Case IV mergers represent the greatest difference in the challenge rates between the two sets of Guidelines. Of the Case IV mergers, 96.8 percent would be challenged under the 1968 Guidelines while only 89.0 percent would be challenged pursuant to the 1982 Guidelines.

Table 5

Horizontal mergers in metropolitan markets

State	Markets	Challengeable under old (1968) guidelines	Challengeable under new (1982) guidelines	Difference: old (1968) minus new (1982)
	(number)	*(number, percent)*	*(number, percent)*	*(number)*
CASE I				
(Largest and second largest)				
Illinois	8	8(100)	8(100)	0
Indiana	11	11(100)	11(100)	0
Iowa	6	6(100)	5(83.3)	1
Michigan	11	11(100)	11(100)	0
Wisconsin	9	9(100)	9(100)	0
All 5 states	45	45(100)	44(97.8)	1
CASE II				
(Smallest and next smallest)				
Illinois	8	0(0)	0(0)	0
Indiana	11	4(36.4)	4(36.4)	0
Iowa	6	0(0)	0(0)	0
Michigan	11	0(0)	0(0)	0
Wisconsin	9	0(0)	0(0)	0
All 5 states	45	4(8.9)	4(8.9)	0
CASE III				
(Third largest and fourth largest)				
Illinois	8	8(100)	6(75.0)	2
Indiana	8	8(100)	8(100)	0
Iowa	6	6(100)	5(83.3)	1
Michigan	11	11(100)	11(100)	0
Wisconsin	9	9(100)	9(100)	0
All 5 states	42	42(100)	39(92.8)	3
CASE IV				
(Fourth largest and fifth largest)				
Illinois	8	4(50.0)	4(50.0)	0
Indiana	8	7(87.5)	7(87.5)	0
Iowa	6	6(100)	3(50.0)	3
Michigan	11	8(72.7)	6(54.5)	2
Wisconsin	9	7(77.8)	5(55.6)	2
All 5 states	42	32(76.2)	25(59.5)	7

• Overall, 86.1 percent of all mergers proposed in rural markets violate the 1968 Guidelines, in contrast with 81.6 percent under the 1982 Guidelines.

Mergers in metropolitan markets

A comparison of the 1968 and 1982 Guidelines relative to 174 mergers in 45 metropolitan markets similarly indicates that the new Guidelines are less stringent than the old.

• All Case I mergers are objectionable under the old Guidelines compared with 97.8 percent under the new Guidelines.

• Case II mergers show no difference between the challenge rate under the two sets of Guidelines and experience the lowest challenge rate, 8.9 percent, of the four cases tested in metropolitan markets.

- Of the Case III mergers, 100 percent violate the 1968 Guidelines while 93.3 percent are challengeable under the 1982 Guidelines.
- Case IV mergers present the greatest difference between the old and the new Guidelines. In this case 76.2 percent would be forbidden by the 1968 Guidelines whereas only 59.5 percent, a decrease of 16.7 percentage points, would be objectionable under the 1982 Guidelines.
- In total, for the mergers proposed in metropolitan markets, 70.7 percent are violative of the 1968 Guidelines, whereas 64.4 percent are subject to challenge under the 1982 Guidelines.

Comparison of rural and metropolitan markets

The criteria embodied in the 1982 Guidelines, on average, are more receptive to horizontal mergers than were the previous guidelines. Furthermore, the impact of the 1982 Guidelines should be most apparent in metropolitan markets rather than in rural markets. On a percentage basis, fewer mergers are challengeable in metropolitan markets than in rural markets regardless of which set of Guidelines are used.

This is not surprising, for rural markets by their nature tend to be highly concentrated due to the scarcity of local banking alternatives. On the other hand, metropolitan markets are distinguished from rural banking markets by having a relatively larger number of banking organizations; relatively lower levels of concentration (as measured by both the concentration ratio and HHI); and more markets in which the smallest banking organizations hold minimal market shares (e.g., less than one percent).[23] Mergers among the smaller organizations in these markets are likely to go unchallenged.

Conclusion

Horizontal mergers in the banking industry are more likely to go unchallenged by the Department under the new Guidelines.[24] If the Board adhered strictly to the new Guidelines it too would be less likely to challenge certain bank mergers. This suggests, that, other things equal, more bank mergers are likely to be proposed and fewer challenged under the 1982 Guidelines than would have been if the 1968 Guidelines remained in effect. The impact of this change should be most apparent for intermediate-sized banking organizations in metropolitan markets (i.e., Case III and Case IV mergers). Of course, the actual enforcement policy of the Department and the Board may be more stringent (or lenient) that the Guidelines themselves suggest.

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[23]This contention is supported by the mean values of the four-firm concentration ratio, pre-merger HHI, and number of banking organizations in rural and metropolitan markets:

Variables	Mean values	
	Rural	Metropolitan
Four-firm concentration ratio	88.5	73.5
Pre-merger HHI	3377	1938
Number of organizations	5.8	30.6

[24]A similar conclusion was reached with regard to the effect on merger policy in New England banking markets. (Joseph E. Gagnon, "The New Merger Guidelines: Implications for New England Banking Markets", *New England Economic Review*, Federal Reserve Bank of Boston, July/August 1982, pp. 18-26.

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