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# CASE 5

# Natural Gas: The Regulatory Transition

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## INTRODUCTION

One of the most significant pieces of legislation dealing with deregulation in American industry is The Natural Gas Policy Act of 1978 (NGPA).[1] This legislation marked the culmination of an extended debate over the regulation of the price of natural gas at the wellhead (the point at which natural gas comes out of the ground to be sold to pipeline delivery systems). The intensity of the policy debate over the NGPA was and is fueled by the sizes of the attendant transfers from consumers to producers.[2]

The contemporary gas industry may be characterized as having three segments: production, pipeline delivery, and local distribution. Natural gas is produced either in fields that primarily yield natural gas or from fields that produce gas and oil together.[3] Producers gather the gas at the wellhead and sell it under contract to pipelines, from which the gas is delivered to various markets. A pipeline may sell the gas directly to a large end-user (such as an industry) or to a local distribution company, which in turn delivers it to an end-user (typically a residential or commercial customer). Since the NGPA does not deal with the regulation of the pipelines or of the local distribution companies, the focus of this case is on the regulation and deregu-

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lation of the price at which a producer sells gas to a pipeline at the wellhead.

Natural gas is a vital part of America's total energy supply. This clean-burning fuel's share of the total energy used in the United States has grown from only 14 percent in 1948 to about 27 percent in 1983 (Table 1). Approximately one-quarter of the yearly gas supply is used by residential consumers, and nearly half is consumed by American industry.

In one sense the industry has come nearly full circle. In the early part of this century there was no federal regulation of natural gas. Wellhead prices of natural gas then became regulated following a combination of legislative and judicial events that took place over an extended period (1938–1954). During the next two decades, regulators struggled with the difficulties of controlling wellhead prices for thousands of productive wells. The regulatory tasks became further complicated in the 1970s as shortages developed and as costs of production changed rapidly. The regulatory turmoil of the 1970s led to the passage of the NGPA in 1978, which specified a phased deregulation of most (but not all) wellhead prices.

We begin with a brief examination of the history of the natural gas industry, including the origin, evolution, and economic consequences of regulation. Prior to the NGPA, discussions of the effects of regulation focused on several areas, including the administrative difficulties of controlling prices, shortages of gas in interstate markets, potential imperfections in wellhead markets, income transfers under regulation, and regulation-related incentives for inefficient utilization of energy resources. We then describe the forces that led to deregulation, particularly the changing market conditions of the 1970s that made it impossible for regulators simultaneously to hold down wellhead prices and avoid shortages of gas.

Table 1. Percentage of Total Energy Produced by Type[a]

| *Source* | *1948* | *1963* | *1978* | *1983* |
|---|---|---|---|---|
| Coal | 48 | 26 | 25 | 28 |
| Natural gas (dry) | 14 | 31 | 32 | 27 |
| Petroleum | 33 | 35 | 30 | 30 |
| Natural gas plant liquids | 2 | 4 | 4 | 4 |
| Hydropower | 4 | 4 | 5 | 6 |
| Nuclear power | 0 | 1 | 5 | 5 |
| Geothermal and other | 0 | 0 | —[b] | —[b] |
| Total gross energy produced (quadrillion BTU) | 35.99 | 46.15 | 61.00 | 61.18 |

*Source: Annual Report to Congress* (1978), Vol. II, Energy Information Administration, Department of Energy, p. 5; and *Monthly Energy Review,* Department of Energy (various issues).

[a]Totals do not equal 100 percent because of independent rounding.

[b]Less than 0.5 percent.



Finally, the discussion turns to the provisions of the NGPA and indicates some of its consequences. Soon after the passage of the NGPA there was concern that rapidly rising world oil prices might cause gas prices to "fly up" dramatically as phased deregulation approached more complete deregulation in the middle of the 1980s, although concerns of this sort all but disappeared as the Organization of Petroleum Exporting Countries (OPEC) weakened and world oil prices fell in 1983 and 1984. More recently, attention has centered on the nature and effects of long-term contracts between gas suppliers and pipelines as both make costly long-term investments under the increased uncertainty of a competitive environment. Under new contracts, deregulated prices may be based on the price of Mexican or Canadian gas (an "imported gas" clause) or a percentage of the energy-equivalent price of fuel oil (an "oil reference" clause). Contracts may require the pipeline to pay for some or all of the gas under contract, even if the pipeline has no market for that gas (a "take-or-pay" clause), or allow the pipelines to offer the producer a lower price than the contractually established price (a "market-out" clause) if, for example, the gas cannot be sold at the contractual price.[4] We will describe these recent developments and their potential consequences in some detail.

## THE REGULATION OF NATURAL GAS

Several factors led to the federal regulation of natural gas. In the 1930s many new large oil and gas fields were found in regions far from the large city markets, particularly in the Southwest. Improved drilling and exploration techniques aided in the discovery of fields. The development of seamless pipe, which greatly reduced the problems with leakage posed by the high pressures required in the transport of gas, made it possible to move the gas from these remote fields to large markets. Thus natural gas moved across state lines to become an important source of energy.

Until 1938 state and local regulators had no power to control the price distributors paid for gas imported from other states. The Supreme Court had held that the interstate pipelines were beyond their reach.[5] After lengthy consideration, Congress passed The Natural Gas Act of 1938, declaring "that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."[6] The Act brought the interstate transmission of natural gas and its sale for resale under the control of the Federal Power Commission (FPC). It exempted the gathering of gas and its retail distribution. The rates for transmission and sale were to be "just and reasonable" and without "undue" preferences.[7] Pipelines were required to publish and adhere to published tariff schedules and to give advanced notice of proposed tariff changes.[8] The Commission was empowered to suspend proposed changes, conduct hearings, order refunds to consumers when warranted, and issue orders to ensure that reasonable rates would prevail.[9] The law differed from earlier similar legislation for the electricity industry (The Federal Power Act of 1935) in one important respect. It did not authorize the FPC to order interconnections among pipelines.

After World War II the federal regulation of wellhead prices became an increasingly important issue. Before pipeline networks were established, gas was often produced as a worthless byproduct of oil production. Often it was burned (flared) at the wellhead. With the advent of pipelines, its value went up rapidly. Prices in new contracts rose. Prices for gas already in production at that time increased as a result of "most favored nation" clauses, which required a purchasing pipeline to pay the producer a price equal to the highest price paid to any other producer within a given area by that pipeline, or in some cases by any pipeline in that area. The pipelines responded by submitting proposals for price increases that they in turn charged to local distributors.

Until 1954 the FPC had assumed (amid spirited debate) that it did not have jurisdiction over the price at which gas was sold at the wellhead. This belief was based on a clause in the 1938 Act stating that the Act "shall not apply . . . to the production or gathering of natural gas," even though these were sales to pipelines for resale.[10] Several states in the gas-consuming areas of the North felt that the FPC should have regulated wellhead prices, while the gas-producing states of the Southwest opposed this view.

The issue came to a head in 1954 in a famous case, *Phillips Petroleum Company v. Wisconsin et al.*[11] Phillips was the largest of the independent gas producers. After Phillips had raised the price of its natural gas, the State of Wisconsin, along with the cities of Milwaukee, Detroit, and Kansas City, complained before the FPC. When the Commission declined to act, the case went to court.



During the testimony on the *Phillips* case, the Wisconsin consumer representatives stated that they felt Phillips had monopoly power in the market for natural gas sales to pipelines, and they were concerned that this power led to excessively high prices at the wellhead and, in turn, for the consumer. Phillips strongly denied the existence of monopoly power. It pointed out that in 1946 and 1947 there were approximately 2,300 independent producers or gatherers supplying gas to the pipelines, so that the supply of gas was in fact quite competitive.[12]

Ultimately the Supreme Court ruled that, while the production activities of Phillips were not regulated within the scope of the Act, the sales of Phillips to pipelines intending resale did fall under its provisions. The Court assigned to the FPC the duty to adjudge the reasonableness of prices for gas sold by Phillips.

The controversy surrounding this ruling arose for two main reasons. First, as already described, it was certainly not clear that Congress intended that the law be interpreted to include regulation of wellhead prices. Second, the nature of any market imperfection that one might cite as a basis for regulating wellhead prices was never made clear. Did producers have sufficient monopoly power to warrant the extension of regulation to them? Kahn points out by analogy that in the electric power industry the assumption has been that suppliers of fuel oil or coal to electricity generating companies have been sufficiently competitive to protect the consumer, and "that as long as they have remained financally independent, the regulated monopolists had no incentive to pay more than the competitive price."[13] In any case, sixteen years after the enabling legislation, regulation was in fact extended to the wellhead.[14]

## Regulation in Practice

Following the *Phillips* decision, the FPC began to regulate wellhead prices. Between 1954 and 1960 "the Commission had accumulated some 11,091 rate schedules and 33,231 supplements to those schedules from 3,372 independent producers," and by 1960 "there were 3,278 producer rate increase filings under suspension and awaiting hearing and decisions."[15] The Commission was confronted with the impossible task of making thousands of individual rate determinations using methods traditionally employed in rate cases for public utilities. The Commission estimated that it would not finish its 1960 caseload until the year 2043.[16]

The impossibility of regulating individual wellhead prices meant that a more pragmatic procedure was necessary. In 1960 the Commission decided to divide the country into twenty-three geographic areas and then set uniform prices for each of them, based on prices in the 1956–1958 period. In 1965 the FPC set its first rate for the Permian Basin area, including parts of New Mexico and Texas. There were really two ceiling prices, one for gas already being produced ("old gas") and for gas associated with oil and the second (higher) price for gas not associated with oil, which was classified as "new gas." New gas referred to gas that was either discovered or first committed to interstate commerce after a date specified by the FPC. The justification for this two-level system of prices was that it "was both undesirable and unnecessary to extend that higher price to old gas, undesirable because to do so would confer windfalls on the owners of reserves discovered and developed at lower costs in the past (a noneconomic argument) and unnecessary because the investments in the old gas had already been made (an economic consideration)."[17] This procedure, called area-wide ratemaking, was soon challenged in court, and in the 1968 Permian Basin Area Rate Cases, the Supreme Court upheld the FPC order.[18]

As the first years of the 1970s passed, it became apparent that the new ratemaking approach was simply too cumbersome to permit the Commission to react promptly and responsively to changing conditions in wellhead markets. By 1974 the FPC had completed proceedings in less than half of the twenty-three geographic areas, and changing market conditions meant that some of the rates already set needed revision. These prospects, along with an increasing gas shortage, led the Commission to reassess its ratemaking practices. On June 21, 1974, the FPC extended the concept of area rate regulation to establish "a uniform just and reasonable national base rate of 42 cents per thousand cubic feet [Mcf] at 14.73 psia [pounds per square inch, absolute pressure], for interstate sales of natural gas."[19] Thus, instead of setting rates by areas, the FPC moved to a policy of establishing nationwide rate ceilings. This procedure was called "nationwide ratemaking."

## CONSEQUENCES OF REGULATION

### The Shortage in Interstate Markets

Before 1970 no "shortages" of gas were observed either in the interstate or intrastate markets. This means that the amount of gas produced nationally was sufficient to meet the contractural demands for shipment by pipelines. Since producers of natural gas in new gas



fields often had the option of selling in either the regulated interstate market or an unregulated intrastate market, one would have expected sales to occur in these markets so that the prices observed were about equal. Table 2 shows that weighted average prices in interstate and intrastate markets were within $0.02 per Mcf of one another.[20] (As noted earlier, actual individual transactions occurred at different prices. A weighted average price indicated in the table is determined as the price that, when multiplied by the total sales volume, would yield the same revenue as did the sum of all of the individual transactions at their respective actual prices.)

However, during the 1970s, production in interstate markets began to fall short of contractual demands by greater amounts each year. Pipeline shipments were curtailed; that is, they delivered less than the contractually agreed-upon amounts to downstream customers.[21] For the period from September 1976 to August 1977, net curtailments of contracted interstate gas deliveries amounted to about 3.77 trillion cubic feet (Tcf), a significant amount considering that the total supply of natural gas was about 19 Tcf for that period.[22] Consequently, some industries cut back production, some users went without service, and many people temporarily lost their jobs. Prospects of increasing shortages helped to push the debate over natural gas to the national forefront during the 1970s.

Among other major concerns was the continual decline in proven

Table 2. Comparison of Intrastate and Jurisdictional Weighted Average Prices ($/Mcf)

| *Date of Contract* | *Intrastate* | *Jurisdictional (Interstate)* |
|---|---|---|
| 1966[a] | $0.168 | $0.185 |
| 1967[a] | 0.173 | 0.191 |
| 1968[a] | 0.175 | 0.192 |
| 1969[a] | 0.180 | 0.198 |
| First half, 1970[a] | 0.207 | 0.202 |
| July 1, 1970, to Sept. 14, 1971[a] | 0.241 | 0.284 |
| Sept. 15, 1971, to Sept. 14, 1972[a] | 0.316 | 0.286 |
| 1975 | 0.60 (est.)[b] | 0.40[c] |

[a] *Source:* FPC data as presented in Report No. 94-732 (House of Representatives, 94th Congress, first session), p. 6.

[b] *Source:* No hard data are available, but this figure was named as a consensus estimate by Chip Schroeder of the House Energy and Power Subcommittee Staff. See L. Kumins, "Cost of S. 3422's Pricing Provisions," Senate Report 94-907.

[c] *Source: FPC News,* 8:35 (week ending August 29, 1975), 1, 5.

reserves. Gas reserves include all the gas that actual drilling has proven to exist and that is therefore potentially available for production. As Table 3 shows, proven reserves declined from 291 Tcf in 1970 to 209 Tcf in 1977. Thus throughout the 1970s the rate of extraction of natural gas exceeded the rate of discovery of new reserves.

There can be little doubt that changing economic conditions, including a higher demand for energy, rising oil prices, declining reserves, and increasing shortages generated pressure on regulators to raise wellhead prices during the 1970s. As Table 3 indicates, by 1972 regulators were holding interstate wellhead prices below the levels observed in the unregulated intrastate markets, and increasingly so over time. This trend toward diverging wellhead prices is even more

Table 3. Natural Gas Supply, Average Wellhead Price, and Consumption

| Year | Total Energy Production (Quadrillion BTU)[a] | Natural Gas (Dry) Produced | | Proved Reserves (Dry Gas) (Tcf)[a,b] | Average Wellhead Value (¢/Mcf)[c] | Total Consumption (Tcf)[a] |
|---|---|---|---|---|---|---|
| | | Quadrillion BTU[a] | Tcf[a] | | | |
| 1948 | 36 | 5.1 | 4.9 | 173 | 6.5 | 4.7 |
| 1949 | 31 | 5.4 | 5.2 | 180 | 6.3 | 5.0 |
| 1950 | 35 | 6.2 | 6.0 | 185 | 6.5 | 5.8 |
| 1951 | 38 | 7.4 | 7.2 | 193 | 7.3 | 6.8 |
| 1952 | 37 | 8.0 | 7.7 | 193 | 7.3 | 6.8 |
| 1953 | 37 | 8.4 | 8.1 | 210 | 9.2 | |
| 1954 | 36 | 8.7 | 8.4 | 211 | 10.1 | 8.1 |
| 1955 | 39 | 9.3 | 9.0 | 223 | 10.4 | 8.7 |
| 1956 | 42 | 10.0 | 15.2 | 237 | 10.8 | 9.3 |
| 1957 | 42 | 10.6 | 10.3 | 245 | 11.3 | 9.9 |
| 1958 | 39 | 11.0 | 10.6 | 253 | 11.9 | 10.3 |
| 1959 | 41 | 12.0 | 11.6 | 261 | 12.9 | 11.3 |

[a]*Source: Annual Report to Congress* (1978), Energy Information Administration, Department of Energy, Vol. 2, pp. 5, 33, 77; and *Monthly Energy Review*, Department of Energy (various issues).

[b]*Source:* Proved reserves are defined to be "the estimated quantities of natural gas, which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future from known natural oil and gas reservoirs, under existing economic and operating conditions." See *Annual Report to Congress* (note [a] above), p. 169.

[c]This column is generated "by dividing the sum of total values of natural gas produced in all States by the sum of total quantities of natural gas produced in all States." See *Annual Report* (note [a] above), p. 85.



Table 3. Natural Gas Supply, Average Wellhead Price, and Consumption—cont'd

| Year | Total Energy Production (Quadrillion BTU[a]) | Natural Gas (Dry) Produced | | Proved Reserves (Dry Gas) (Tcf)[a,b] | Average Wellhead Value (¢/Mcf)[c] | Total Consumption (Tcf)[a] |
|---|---|---|---|---|---|---|
| | | Quadrillion BTU[a] | Tcf[a] | | | |
| 1960 | 42 | 12.7 | 12.2 | 262 | 14.0 | 12.0 |
| 1961 | 42 | 13.1 | 12.7 | 266 | 15.1 | 12.5 |
| 1962 | 44 | 13.7 | 13.3 | 272 | 15.5 | 13.3 |
| 1963 | 46 | 14.5 | 14.1 | 276 | 15.8 | 14.0 |
| 1964 | 48 | 15.3 | 14.8 | 281 | 15.4 | 14.8 |
| 1965 | 50 | 15.8 | 15.3 | 287 | 15.6 | 15.3 |
| 1966 | 53 | 17.0 | 16.5 | 290 | 15.7 | 16.5 |
| 1967 | 55 | 18.0 | 17.4 | 293 | 16.0 | 17.4 |
| 1968 | 57 | 19.1 | 18.5 | 287 | 16.4 | 18.6 |
| 1969 | 59 | 20.5 | 19.9 | 275 | 16.7 | 20.1 |
| 1970 | 63 | 21.7 | 21.0 | 291 | 17.1 | 21.1 |
| 1971 | 62 | 22.3 | 21.6 | 279 | 18.2 | 21.8 |
| 1972 | 63 | 22.2 | 21.6 | 266 | 18.6 | 22.1 |
| 1973 | 62 | 22.2 | 21.7 | 250 | 21.6 | 22.1 |
| 1974 | 61 | 21.2 | 20.7 | 237 | 30.4 | 21.2 |
| 1975 | 60 | 19.6 | 19.2 | 228 | 44.5 | 19.5 |
| 1976 | 60 | 19.5 | 19.1 | 216 | 58.0 | 20.0 |
| 1977 | 60 | 19.6 | 19.1 | 209 | 79.0 | 19.5 |
| 1978 | 61 | 19.3 | 18.9 | 208 | 91.9 | 19.4 |
| 1979 | 64 | 20.1 | 19.6 | 201 | 118.0 | 20.2 |
| 1980 | 65 | 19.9 | 19.4 | 199 | 159.0 | 19.9 |
| 1981 | 64 | 19.7 | 19.2 | 202 | 198.0 | 19.4 |
| 1982 | 64 | 18.3 | 17.9 | 202 | 246.0 | 18.1 |
| 1983 | 61 | 16.5 | 16.1 | — | 259.0 | 15.5 |

easily observed if one examines the prices in new gas contracts over the period (instead of weighted average prices). "During 1969–1975, interstate natural gas prices for new contracts rose by 158 percent, from approximately $0.198 per Mcf to over $0.51 per Mcf. However, during the same period, intrastate natural gas prices rose at an even greater rate, from approximately $0.18 per Mcf in 1969 to in excess of $1.35 per Mcf in 1975, a 650 percent increase."[23] At the time of the passage of the NGPA in 1978, average intrastate prices for new contracts and for renegotiated or amended contracts were often over $2 per Mcf.

As the difference between prices of new gas sold in the two markets increased over the first half of the 1970s, producers were given incentives to commit newly found reserves to an intrastate (rather than the interstate) market. In the 1964–1969 period producers dedicated 67 percent of their new reserves to the interstate market, but this figure fell to less than 8 percent over the 1970–1973 period.[24]

## Income Redistribution

Figure 1 depicts a supply schedule for producers and a demand schedule for consumers of natural gas in the interstate wellhead market. The regulated price, $P_R$, is below the unregulated price, $P_E$. As a result, only $Q_S$ is actually supplied to customers, while the demand for $(Q_D - Q_S)$ remains unsatisfied. Under these conditions pro-

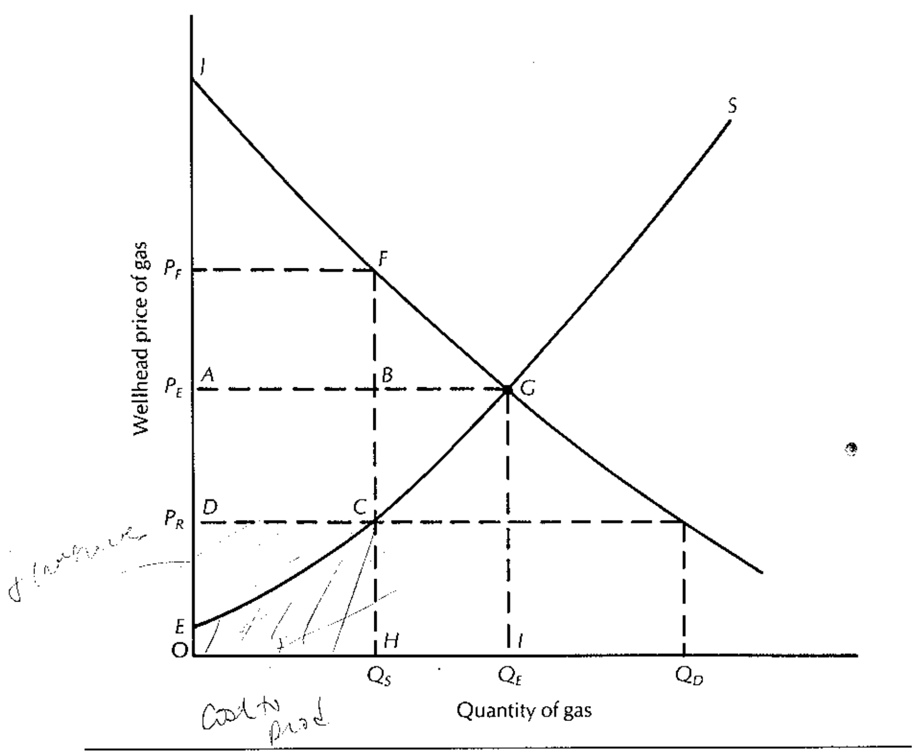


Figure 1. The Interstate Wellhead Market



ducers realize dollar revenues corresponding to the area *DCHO* and incur costs of *OECH*, leaving them with dollar profits represented by the area *CDE*. If those consumers who were successful in obtaining the quantity $Q_S$ had paid the unregulated price, $P_E$, then producer profits would be increased by the amount *ABCD*, and consumer expenditures would be increased by the same amount. In short, regulation effectively transfers *ABCD* from producers to consumers. (In discussing the estimated size of these transfers, however, we will see that there is some doubt that the income redistribution is adequately measured by *ABCD* alone.)

Since the unregulated intrastate and regulated interstate prices were approximately equal until 1970, there was relatively little income redistribution from price regulation at that time. However, since interstate and intrastate prices diverged significantly by the mid-1970s, the effects of income redistribution became quite large. Table 3 shows that approximately 19 Tcf were produced in 1975. About two-thirds of this (say, 13 Tcf) was sold in interstate commerce. Table 2 shows that the weighted-average price was thought to be about 20 cents per Mcf higher in intrastate than in interstate markets. It is not unreasonable to believe that virtually all of this difference resulted from regulation. Thus the amount of income redistribution can be approximated as the product of 13 Tcf and 20 cents per Mcf, or about $2.6 billion for the year. While this is only an approximation, it serves to emphasize that the redistribution may well have been in the billions of dollars annually during the middle of the 1970s.[25]

Helms (1974) has suggested an additional aspect of income redistribution occurring under regulation. He noted that while some consumers were "fortunate" enough to be able to purchase gas, other consumers were not able to acquire gas at all. Those consumers were forced to seek alternative sources of energy, including imported gas, at much higher prices. His conclusion is that while regulation may have redistributed income from producers to those fortunate consumers, a large amount of income was also redistributed away from other consumers, in many cases to foreign instead of domestic suppliers.

## Economic Efficiency

Since a demand schedule shows how much gas buyers would like to purchase at any announced price in the market, it can be used to determine the value of a given quantity of gas to consumers. For example, in Figure 1, suppose $Q_S$ were provided to all consumers willing to pay at least $P_F$.[26] Then the gross value of that gas can be represented in dollars by the area *OHFJ*.[27] However, since it costs producers an amount *OHCE* to produce the gas, then the net economic benefit of producing $Q_S$ is the area *ECFJ*. How this net economic benefit (or, as it is often called, net surplus) is divided between consumers and producers depends on the price charged. If the regulated price, $P_R$, is in effect, then the consumer surplus is *DCFJ*, and the producer surplus is *ECD*.

Now suppose that regulation were removed, so that the price in the market could move to $P_E$ (at which the market clears). The quantity of gas offered for sale would increase by the amount $(Q_E - Q_S)$. A measure of the gross value of this additional gas is the area *HFGI*. The costs to producers of providing this additional gas would be *HCGI*. Note that *HFGI* is larger than *HCGI*. Therefore a net benefit increase would be realized if regulation were removed, where the size of the net additional value is represented by the triangular area *CFG*. In other words, regulation may prevent the market from allocating $(Q_E - Q_S)$ to consumers even though the benefits they attach to the additional gas exceed the costs of producing that gas. Economists therefore say that gas is not being produced or allocated efficiently under regulation, and they call the net benefit loss *CFG* an "efficiency loss."

There are reasons to believe that the efficiency losses under regulation were even larger than *CFG*. To understand this, recall that at the regulated price, $P_R$, only $Q_S$ will be supplied to customers. There is no guarantee that the customers who actually get the gas value it the most. Restated, gas may not be allocated so that customers get the most benefit from it. It may very well be that some people valuing the gas less than $P_E$, indeed as low as $P_R$, are receiving gas under regulation. At the same time others willing to pay very high prices (even higher than $P_E$) may be rationed out of the market. All one can say is that *CFG* places a lower bound on the deadweight loss due to regulation.

MacAvoy (1975) proposes a slightly different way of looking at efficiency losses to define a better lower bound on them. It is worthwhile developing that notion here, since he has provided some empirical estimates using this method. He notes that the demand for gas can be considered in two parts, as depicted in Figure 2. There is one set of consumers who are able to purchase gas at regulated prices. Typically, those consumers who have had access to gas in one year will continue to have access in the next year. One could represent the demand schedule for this group of consumers by $D'$ in the figure.

As time passed, many new would-be consumers were not able to purchase gas because of the shortage. If the demand of this unfortunate group were added to $D'$, the actual demand for gas could be



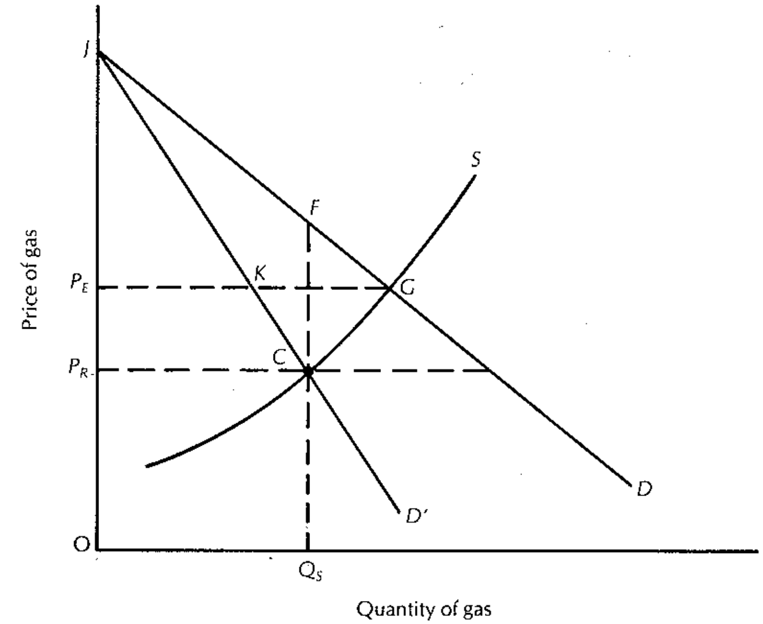


Figure 2. Efficiency Loss: Two Consumer Groups

represented by *D*. (In Figure 2 it is assumed that neither existing nor potential customers would purchase any gas at a price higher than that represented by point *J*.) Most of the burden of the shortage will be borne by new would-be consumers who cannot get gas at all, since existing customers will be served first. Thus, in addition to the efficiency loss *CFG* (in Figure 2), there is an additional loss of *CFJ*. The loss *CFJ* arises because some prospective consumers who are not able to get gas value it more than some of the "fortunate" consumers who can purchase it. Thus gas is not being allocated to the consumers who place the highest value on it.

MacAvoy and Pindyck (1975) estimated that if regulation were to have continued at the 1974 prices for the rest of the decade, then the efficiency loss would have been more than \$2.5 billion in 1978 and more than \$5.8 billion in 1980. To our knowledge no one has attempted to reestimate the size of the loss given that the increases in regulated prices and intrastate prices were more rapid than MacAvoy and Pindyck assumed. Further, their procedure requires extensive assumptions about the nature of the demand for natural gas in order to calculate the size of the area *CGJ* in Figure 2. MacAvoy and Pindyck assumed the demand schedule was linear, a procedure that could introduce significant error if incorrect, since the difference between regulated and unregulated prices is quite large.[28]

## WELLHEAD MARKET STRUCTURE

As the debate about deregulation became more intense in the 1970s, it was natural that investigators should ask whether the wellhead market structure was conducive to competition. That is, if there were substantial anticompetitive behavior at the wellhead level, some justification for field price regulation might exist. Space does not allow more than a brief summary of the evidence here. Although the issue of monopoly power was raised in the *Phillips* case, subsequent analyses have cast doubt on the proposition that monopoly power was in fact a problem in the industry. The existence of literally thousands of independent producers alone makes such an argument difficult to accept.

The possibility of monopsony power by pipelines was frequently highlighted in the studies. This argument states that if, for example, only one pipeline were buying gas from a given field, it might not act as a wellhead price taker. Rather, it might perceive and exploit the fact that the wellhead price varied directly with the amount of gas it purchased. The most famous studies of wellhead market structure in the 1950s were by MacAvoy (1962, 1970a, 1970b) and Neuner (1960). MacAvoy constructed statistical tests designed to see if observed variations in wellhead prices across field (that is, wellhead) markets significantly depended on the number of pipeline buyers in the market. He concluded that monopsony power was not pervasive, although in a few areas there was some evidence of its existence.[29]

Empirical testing of monopoly and monopsony power in the period after regulation was implemented will be difficult for at least two reasons. First, interstate market prices were controlled, so that variations in prices over regions result from many factors addressed in regulatory proceedings rather than monopoly or monopsony power. Second, until the NGPA, the only remaining markets in which price fluctuated without regulation were the intrastate markets, and data have only recently been recorded at the Department of Energy on a consistent reporting basis. This is somewhat unfortunate, since it is reasonable to suppose that any markets that were to some extent monopsonistic in the past would be presumably less so now than just



before regulation, as natural gas markets have grown and new entrants have appeared.[30]

## THE NGPA: PROVISIONS AND CONSEQUENCES

The NGPA represented a major change in the structure and direction of regulation in the natural gas industry. In three areas the Act entails significant changes from the past. First, the Federal Energy Regulatory Commission (FERC) was granted regulatory control over intrastate as well as interstate wellhead prices. Second, the Act contained a time schedule for the deregulation of new and old gas produced from "high-cost" sources (see the description of production categories in Table 4), and it indicated a set of wellhead prices to be in effect for new gas during the transition to deregulation. Old gas prices will remain regulated indefinitely. Third, the Act provided a set of rules under which the interstate pipelines must pass along the higher costs incurred with the purchase of "high-cost" gas to selected large industrial customers. This is known as the "incremental pricing" provision of the Act.

In addition, the NGPA empowers the President to declare a natural gas emergency if a shortage that would endanger supplies to certain high-priority users exists or is imminent. In such an emergency the President can authorize pipelines and local distributors to purchase gas at any price he believes to be appropriate. If these emergency purchases are insufficient to meet designated high-priority needs, the President can reallocate gas supplies as necessary under some circumstances.[31] The Act also provides guidelines for a system of curtailments during times of shortage.

A convenient summary of the price ceilings set by the NGPA has been provided by the FERC and appears in Table 4. As noted earlier, the NGPA extends regulation to include intrastate markets. Together with the already numerous categories of interstate gas defined by regulators before the Act, there existed an even more complicated set of categories after its passage. As Table 4 shows, the old gas is not to be deregulated. However, several categories of gas were deregulated in January of 1985, with still more to be deregulated in 1987. The Act specified a set of transition prices between 1978 and the middle of the 1980s when regulation was to be phased out of many of the categories of gas. As world oil prices rose more rapidly than expected during the late 1970s and early 1980s, there was concern that the transition path of prices specified in the Act was not high enough, and that in 1985 a

Table 4. Maximum Gas Price Ceilings Set by the NGPA

| *Section of the Act* | *Price per Million BTUs*[a] | *Category of Gas* | *Date of Deregulation* |
|---|---|---|---|
| 102 | \$1.75 + inflation[b] and escalation[c] (\$2.07)[d] | *New Natural Gas*<br>New outer continental shelf (offshore) leases (on or after 4/20/77)<br>New onshore wells<br>(1) 2.5 miles from the nearest marker well[e]<br>(2) If closer than 2.5 miles to a marker well, 1,000 feet deeper than the deepest completion location of each marker well within 2.5 miles<br>New onshore reservoirs | 1/1/85 |
| | | Gas from reservoirs discovered after 7/27/76 old (pre-4/20/77) offshore continental shelf | Not deregulated |
| 103 | \$1.75 + inflation (\$1.97)[d] | *New Onshore Production Wells*<br>(Wells, the surface drilling of which began after 2/19/77, that are within 2.5 miles of a marker well and not 1,000 feet deeper than the deepest completion location in each marker well within 2.5 miles) | |
| | | Gas produced above 5,000-foot depth | 7/1/87 |
| | | Gas produced from below 5,000-foot depth | 1/1/85 |
| 104 | | *Gas Dedicated to Interstate Commerce Before The Date of Enactment*<br>(Rates previously set by FPC) | Not deregulated |
| | \$1.45 + inflation (\$1.63)[d] | From wells commenced from 1/1/75–2/18/77 | |
| | \$0.94 + inflation (\$1.06)[d] | From wells commenced from 1/1/73–12/31/74 | |
| | \$0.295 + inflation (\$0.33)[d] | From wells commenced prior to 1/1/73 | |
| | Applicable FERC rate + inflation | Other gas (gas produced by small producers, gas qualifying for special relief rates, etc.) | |
| 105 | Contract price[f] | *Gas Sold Under Existing Intrastate Contracts*<br>If contract price is less than Section 102 price, it may escalate, as called for by contract, up to Section 102 price<br>If contract price exceeds Section 102 price, then contract price plus annual inflation factor or Section 102 price plus escalation applies, whichever is higher | 1/1/85 — if contract price exceeds \$1.00 by 12/31/84; if lower, not deregulated |
| 106 | | *Sales of Gas Made Under "Roll-Over" Contracts*<br>(An expired contract that has been renegotiated) | |
| | \$0.54 or other applicable FERC price + inflation (\$0.61)[d] | Interstate | Not deregulated |

*Source: FERC Fact Sheet* (November 1978).

[a]Under the NGPA, if natural gas qualifies under more than one price category, the seller may be permitted to collect the higher price. The ceiling prices set by the NGPA do not include state severance taxes.

[b]These prices include an "annual inflation adjustment factor" in order to adjust prices for inflation. The price for a given month is arrived at by multiplying the price for the previous month by the monthly equivalent of the annual inflation factor. Since most of the prices set by the NGPA are as of April 20, 1977, the adjustment for inflation begins in May 1977.

[c]These prices will escalate monthly, in addition to the inflation adjustment factor, by an annual rate of 3.5 percent until April 1981, after which they will escalate by 4 percent.

[d]The estimated maximum ceiling price as of October 1978, due to operation of inflation and escalation adjusters.

[e]A marker well is any well from which natural gas was produced in commercial quantities after January 1, 1970, and before April 20, 1977, with the exception of wells the surface drilling of which began after February 19, 1977.

[f]The average price reported to the FERC for intrastate gas sales contracted for during the second quarter of 1978 was approximately \$1.90.

*Continued.*

Table 4. Maximum Gas Price Ceilings Set by the NGPA—cont'd

| *Section of the Act* | *Price per Million BTUs*[a] | *Category of Gas* | *Date of Deregulation* |
|---|---|---|---|
| | The higher of expired contract price or \$1.00 + inflation (\$1.13)[d] | Intrastate | 1/1/85 if more than \$1.00 |
| 107 | | *High-Cost Natural Gas* | |
| | \$1.75 + inflation + escalation[c] (\$2.07)[d] | Production from below 15,000 feet from wells drilled after 2/19/77 | Deregulated on effective date of FERC incremental pricing rule called for by the Act (approximately one year after enactment) |
| | Applicable rate under the Act or higher incentive rate as set by FERC | Gas produced from geopressurized brine, coal seams, Devonian shale | Deregulated on effective date of FERC incremental pricing rule called for by the Act (approximately one year after enactment) |
| | Applicable rate under the Act or higher incentive rate as set by FERC | Gas produced under other conditions the FERC determines to present "extraordinary risks or costs" | Not deregulated |
| 108 | \$2.09 + inflation (after 5/78) + escalation[c] (\$2.21)[d] | *Stripper Well Natural Gas* (Natural gas not produced in association with oil, which is produced at an average rate less or equal to 60,000 cubic feet per day over a 90-day period) | Not deregulated |
| 109 | \$1.45, or other "just and reasonable" rate set by FERC, + inflation (\$1.63)[d] | *Other Categories of Natural Gas* Any natural gas not covered under any other section of the bill; Natural gas produced from the Prudhoe Bay area of Alaska | Not deregulated |



"fly up" of prices would be experienced as decontrol took place. However, with the sharp decline in world oil prices after 1981, the fear did not materialize.

New gas prices can now be expected to approximate marginal costs, since regulatory control does not apply to that gas. Since old gas prices are still controlled, the weighted average price of gas at the wellhead will still be below marginal cost, and some incentive for inefficient utilization of gas will remain.[32] The extent of this incentive will diminish as new gas constitutes an even greater portion of gas production streams.

Another potential source of inefficiency arises from the NGPA specification of ceiling prices that differ by type of well. Consider the following example as illustrative of this type of inefficiency. Suppose that regulation imposes a ceiling of 40 cents per Mcf on gas produced by well A and \$1.80 per Mcf on gas from well B. A substantial increase in the rate of production might be obtained from well A by any of a number of technological processes (such as water flooding, fracturing the formation to improve the rate of flow, and chemical treatment) that might raise the marginal cost of production to, say, 50 cents per Mcf. These improvements will not be made, however, since regulation allows only 40 cents per Mcf. At the same time well B is producing gas that costs as much as \$1.80 per Mcf. Thus it is quite likely that the total cost of producing any given amount of gas is significantly higher under the NGPA than it would be if differential price ceilings were not in force.[33]

## REGULATION AND CONTRACTING IN NATURAL GAS MARKETS

### Regulation and Contracting: An Explanation

*Producer-Pipeline Contractual Arrangements.* In the mid-1980s many gas consumers began to question deregulation when they found their gas rates rising in spite of generally falling energy prices. They were told that this was due to certain contracts — especially "take or pay" contracts — that the pipelines had signed. Many were suspicious. Actually, these contracts were quite normal arrangements that had been in use for decades, dating back to before regulation, although the regulatory environment of the 1970s had encouraged their wider use. As discussed, analyses of natural gas regulation have closely reflected the perception of the problem at the time — from studies of horizontal structure and conduct in the industry in the 1950s and 1960s to concerns in the 1970s over the shortage of natural gas induced by wellhead price regulation. The passage of the NGPA focused attention on future increases in wellhead prices as price ceilings were phased out. Both producers and pipelines had reason to believe that the demand for gas by final users would be strong, given the history of excess demand for gas (because of binding price controls) and of the high and rising price of oil, a major substitute.

Reflecting this emphasis on information in addition to that contained in current prices, policy focus has recently shifted to the impact of changes in regulation on contracts between wellhead producers and pipelines. This is important. Studies of regulation in the natural gas market have almost totally focused on impacts on wellhead prices. However, "price" is only one of many provisions negotiated in the complicated contracts between producers and pipelines. The dominance of long-term contracts (often of at least twenty years' duration) with both "price" and "non-price" provisions widens the scope of the effects of wellhead price regulation — and deregulation.

This so-called contracts problem is now a major policy issue as wellhead price ceilings are being lifted. We summarize the problem briefly below and describe it in detail later. In the late 1970s, as oil prices rose rapidly, pipeline companies found themselves constrained from competing for supplies by wellhead price ceilings, and bargained more on non-price provisions instead. Chief among these was the guarantee to purchase a minimum quantity each year, regardless of downstream demand — the so-called "take-or-pay" clause.

Expectations about future events figure prominently in contract negotiations in two respects: (1) anticipation of wellhead price decontrol in the future and (2) forecasts of the future price of oil. The former should elicit contractual concessions from pipelines trying to compete for additional future supplies. The latter is a major source of uncertainty about future gas prices, as in our earlier discussion of the predicted "fly up" in wellhead prices in the 1980s. Expectations that the increase in oil prices during the late 1970s would be permanent again suggests increased compensation of producers in new contracts.

However, in the early 1980s, as price ceilings were being phased out, gas prices did not rise as much as expected, largely as a result of the decline in world oil prices. Saddled with contracts reflecting the hope of rising gas prices, many pipelines face take-or-pay obligations that exceed the value of their assets. Some pipelines confront the choice between contract abrogation and bankruptcy.[34] Congress has considered legislative measures that would release pipelines from their contract commitments, on the grounds that their predicament is itself due largely to federal regulation.



The extent to which price regulation is responsible for the current contract imbroglio requires an explanation of the use of non-price provisions in producer-pipeline contracts both in the absence and presence of regulation. In the following discussion we draw heavily on the recent theoretical and empirical study of producer-pipeline contractual arrangements in Hubbard and Weiner (1984).

Transactions costs (Williamson, 1975) provide a basic reason for contracting in the gas market. Because of the "specific capital" (that is, capital useful only in the particular transactional arrangement involved in individual producer-pipeline relationships), trade organized through spot exchange is costly. "Opportunism" is likely to be a serious problem when uncertainty is great and when the cost of failure to come to terms is high.[35] Once the initial gas well development costs are sunk, a pipeline faces the temptation to appropriate some of the rents (revenues above production costs) from production unless the producer has an alternative means of sale. Realizing this, the producer demands a long-term contract with adjustment clauses beforehand. The pipeline is itself a form of specific capital; once constructed, it would be prohibitively expensive to move. Since it is best operated near full capacity, a long-term contract "guaranteeing supplies" is in the buyer's interest as well.

Wellhead price regulation may provide an additional motivation for long-term contracting. If pipelines are not free to offer market-clearing prices in order to obtain additional gas, they may sidestep the regulation by granting more generous non-price concessions. Take-or-pay provisions, which specify a minimum lump-sum payment per year from pipeline to producer, are a good example.

Of course, not all variables affecting the contract can be anticipated by the transacting parties. In general, contracts specifying only price are not efficient, because in the absence of future markets, prices allocate both risk and commodities. Signatories can in many cases obtain efficient contracts by making the payment rule conditional on a few key variables such as output and general prices indices easily verified by both parties.

One case is particularly instructive. Suppose that the dominant source of uncertainty stems from the demand side (for example, because of fluctuations in the price of oil). Given this assumption, the efficient contract involves both a take-or-pay provision (essentially a lump-sum payment) and "price payment" equal to the marginal cost of production for gas taken.[36] The contract will leave the choice of output to the pipeline, with a payment rule combining "price" and "non-price" provisions so as to leave producers indifferent to the level of production. The lump-sum guarantee offers producers insurance against fluctuations, while payments on the margin are efficient. This arrangement is appropriate for the demand uncertainty case, since it is the pipeline that faces downstream fluctuations in demand and can adjust takes accordingly. Interestingly, take-or-pay requirements were used extensively in producer-pipeline contracts even before the 1954 advent of wellhead-price regulation. Indeed, MacAvoy (1962) notes that a typical contract specified a take-or-pay of about 80 percent of wellhead capacity, even in the early 1950s.

Thus, even in the absence of wellhead price controls, an expectation of rising oil prices would lead pipelines to increase the total compensation to producers in new contracts (because of the resulting anticipation of higher gas prices). That such price expectations turn out to be wrong later on vitiates neither the desirability of the contract nor its efficiency.

Now consider the case wherein price controls are imposed. Under binding field price control regulation there is a gap between the marginal willingness to pay for new supplies and the marginal opportunity cost of production at the controlled price. Going back to the "demand uncertainty" case above, to the extent that field price controls are binding, there will be excess demand for gas, and uncertainty materializes in demand fluctuations. Equilibrium production is no longer efficient, as pipelines would be willing to raise producer prices to attract more gas, but price regulation stops them from doing so. This situation persists as long as controls remain. Price regulation, then, introduces no new dimensions per se to the negotiation problem producer and pipeline, though it may alter the relative reliance on different provisions.

*Deregulation and the "Contracts Problem."* Understanding the nuts and bolts of the "contracts problem" in the early 1980s requires an analysis of contracting during the transition from regulation to total deregulation. While contract provisions may be similar in the two extremes, a period of transition can bring unanticipated gains or losses to parties as long as market conditions are uncertain. The magnitude of those gains and losses depends on the type of deregulation — immediate decontrol versus phase deregulation.

Consider for example the events of the late 1970s and early 1980s. A demand shock from an increase in the price of oil caused an increase in the market-clearing price-quantity combination. If decontrol were immediate and total, wellhead prices would increase. There would be no need to increase reliance on non-price provisions — that is, no significant change in price escalators or take-or-pay requirements.

However, given phased decontrol — or, in general, anticipated future decontrol — competition for new supplies in the current period requires an increase in "other payments" (such as higher future prices or take-or-pay requirements). As long as the oil price increase is



expected to continue, the pipeline should be willing to grant concessions, as with the anticipated price change due to future deregulation.

For example, by increasing the take-or-pay requirement, the pipeline in effect extends additional insurance to the producer. That is, if the demand for gas declines (because of a decline in economic activity or the price of oil), the producer's revenue is still stabilized because of the take-or-pay provision. The producer obtains this "downside protection" at no cost, because if demand is high, he still receives the additional revenue from greater output.

A "contracts problem" can arise under phased decontrol if, contrary to expectations, the demand shock is not permanent — particularly if non-price contract provisions include high take-or-pay requirements or rigid downward prices. Suppose for example that the oil price increase is temporary and subsequently oil prices decline. As a result of the oil price decline, at the agreed-upon price, the gas may not be marketable downstream. Pipelines incur losses on the high take-or-pay requirements to which they agreed on the anticipation of higher future prices. Such losses do not imply that contracts are necessarily inefficient but reflect the hazards of operating via contracts in a market subject to shocks.

This does not imply that natural gas price regulation is "blameless" in causing the contracts problems. First, the excess demand for natural gas accompanying a binding price ceiling will lead to increased reliance on contract provisions other than current-period price, leaving pipeline profits more vulnerable to external forces — such as changes in the price of oil or in economic growth.

Second, the type of transition from regulation to laissez-faire is important. Immediate decontrol will focus the negotiation of new contracts on price changes (marginal compensation), while anticipated phased decontrol will require increases in concessions not related to current prices (inframarginal compensation) — for example, take-or-pay provisions, which increases vulnerability to market shifts. With respect to public policy, discussion of the second point involves a comparison of the benefits of phased decontrol with the costs imposed by contract rigidities.

Policy concern extends beyond the contracting parties. For example, as noted in a recent study by the U.S. General Accounting Office:

> An increase in gas prices at the wellhead, because of the operation of contract clauses, will increase a pipeline's average acquisition costs for all of its gas supply and, thus, increase the cost of gas to its customers. As these increased acquisition costs plus normal charges for transportation and distribution push the retail price of gas to where it approaches or exceeds the price of residual fuel oil, price sensitive industrial and electric utility consumers could switch to this alternative fuel. Such a drop in industrial

and electric utility demand for natural gas and subsequent loss of pipeline load could in turn lead to further increases in residential prices (1983, pp. iii–iv).

The temporary losses faced by some market participants as a result of previous contractual commitments do not negate the importance and desirability of wellhead price deregulation. First, while the interaction of market uncertainty and past regulation contributed to the current "contracts problem," continuing regulation would extend the distortions in natural gas production and consumption. Second, contracting parties are proving to be flexible as economic conditions in the gas market change; new contracts carry less restrictive provisions than those signed a few years ago, and many existing contracts are being renegotiated. Public policy should facilitate this market transition, rather than overturning all existing contracts or reimposing wellhead price controls.

## Regulation and Contracting: Evidence

Below we present some summary evidence on the impact of regulation on the structure of long-term contracts based on contract surveys conducted by the Energy Information Administration. Table 5 illustrates the sensitivity of minimum-purchase provisions to current and anticipated demand conditions. A striking pattern occurs in the percentage "take" requirements across contracts of different vintages. Take-or-pay requirements rose by nearly 50 percent between the pre-1973 period and the period between 1973 and 1977. The second period witnessed the anticipation of field price deregulation and the excess demand for gas caused by the explosion in oil prices. As the excess demand situation began to reverse, the average minimum-purchase provision declined somewhat, but remained high relative to the pre-oil-shock level.

In addition to take-or-pay provisions, natural gas contracts typically include a set of price-escalator provisions and a set of buyer-protection provisions. The former divide into both "definite" and "indefinite" (indexed to the price of oil or to the highest price paid for gas in the same area) components. Moreover, "minimum-price" provisions set a floor to the price paid or to a price increase. The latter category is typified by "market-out" clauses allowing the pipeline to default on contractual obligations if the gas is not marketable at the agreed upon price and by "maximum-price" provisions, which set a ceiling on the price paid.

For example, patterns similar to those for take-or-pay requirements reported in Table 5 exist for other non-price provisions reported in the studies by the Energy Information Administration. Splitting new contracts signed in the pre-NGPA period into two intervals (pre-1973 and 1973 to April 20, 1977), "minimum-price" provisions covered 69 percent of the volume of gas traded by the second period, as opposed to 39 percent before. Coverage by "market-out" provisions declined from 12 percent to roughly zero.

Perhaps the most convincing evidence on the impact of regulation on take-or-pay provisions and the "contracts problem" comes from a sample of producer-pipeline contracts we obtained from a survey conducted in 1982 by the Energy Information Administration. These contracts cover sales of natural gas in interstate commerce from 615 producing wells in the continental United States. The survey selected contracts signed after 1978, grouping them by "sections" assigned by the NGPA. Specifically, gas sold under Sections 102 ("new" natural gas), 103 ("new" onshore production wells), and 107 ("high-cost" gas from deep wells, Devonian shale, tight sands, or geopressurized brine) was included.

In Table 6 we present the average take-or-pay percentages for the three sections in our sample. Since gas sold under Section 107 was not subject to price controls, we would predict that the mean take-or-pay requirement would be lower than that for Section 102 gas. Technically, price ceilings were lower for Section 103 gas, but because it was produced at a much lower cost than Section 102 gas, price controls were relatively more binding on Section 102 gas. Hence the prediction would be that the take-or-pay percentage for Section 103 would be less than that for Section 102. These predictions are corroborated by the data.[37]



Table 5. Take-or-Pay Provisions by Contract Vintage

| *Contract Vintage* | *Take-or-Pay Requirement (%)*[a] |
|---|---|
| Pre-1973 | 59.6 |
| 1973 to April 20, 1977 | 85.9 |
| April 21, 1977 to November 8, 1978[b] | 82.3 |
| November 9, 1978–1979 | 82.5 |
| 1980 | 78.3 |

*Source:* U.S. Energy Information Administration (1983), p. ix.

[a]Weighted-average percentage minimum-purchase requirement (take-or-pay) based on percentage of deliverability or capacity.

[b]The Natural Gas Policy Act was enacted on November 9, 1978.

Table 6. Average Take-or-Pay Requirements by *NGPA* Section (Post-1978 Contracts in 1982 *EIA* Survey)

| *NGPA Section* | *Take-or-Pay Requirement (%)* |
|---|---|
| 102 | 92.2 |
| 103 | 84.4 |
| 107 | 82.7 |

*Source:* Hubbard and Weiner (1984).

The anticipation of wellhead price decontrol and high future demand for gas because of rising world oil prices gave producers the upper hand in negotiating new contracts with pipelines during this period. The same data indicate further non-price concessions to producers of controlled gas (NGPA Sections 102 and 103) through more infrequent use of "buyer-protection" clauses. Specifically, "maximum-price" provisions appeared in 37 percent of the Section 107 contracts versus 6 percent for Section 102 contracts and 4 percent for Section 103 contracts. "Market-out" provisions were also much less common in contracts signed under Sections 102 (16 percent) and 103 (16 percent) than under Section 107 (36 percent).

This approach of considering the effects of federal regulation on the contractual arrangement as a whole and not just on the wellhead price assumes continued importance in analyzing policy proposals and new market arrangements in the era of price deregulation. The transition to the deregulated environment will be much slower than would be predicted by looking only at dates of legislation. The great majority of gas produced from post-NGPA wells is sold under contracts not expiring until after 1985; 43 percent do not expire until after 1990, and 28 percent do not expire until after 1995.

The contractual problems arising during this lengthy transition period are already leading to extensive litigation. Between 1981 and the beginning of 1984, at least sixteen interstate pipelines exercised "market-out" provisions in their contracts for high-cost gas (U.S. Energy Information Administration, 1983b). Other pipelines, seeking to avoid loss of load downstream from industrial fuel-switching, have invoked *force majeure* clauses to obtain relief. Perhaps most sweeping in its potential impact, some distribution companies have sued to block pipelines' ability to pass through high purchased gas costs to consumers (see the *Columbia Gas Transmission Corporation* case, 1982).



## New Market Arrangements

Current inflexibility in producer-pipeline contracts is stimulating both policy discussion and new market arrangements. In 1983 the Reagan administration[38] put forth a renegotiation proposal allowing either party to "market out" of a gas contract that has not been renegotiated by January 1, 1985. The proposal would have reduced take-or-pay obligations by declaring take-or-pay requirements greater than 70 percent of field capacity to be legally unenforceable (a feature shared by some congressional proposals).

The administration's proposal also encouraged a change in the producer-pipeline relationship by providing incentives (through higher allowed markups) for "contract carriage," in which pipelines would no longer hold title to the gas they transport. In addition, many other proposals would have increased incentives for pipelines to consider contract carriage by making it more difficult to pass through exceptionally high purchased gas costs.

The higher risks of operating in a deregulated market also create the potential for changes in market structure — for example, vertical integration of pipelines and producers or joint ventures. Such developments would require new research to assess the competitiveness of different segments of the gas market. Another mechanism for enhancing short-run flexibility would be the operation of spot and futures markets in natural gas (see the discussion in U.S. Energy Information Administration, 1983b).[39]

Vertical integration can be a cause for policy concern. Even if pipelines continue to be regulated as they presently are (except for wellhead price regulation), and even if a producer delivering gas to an affiliated pipeline is surrounded by other competing producers, there is reason to be wary. If regulators of the pipeline were not observant, the affiliated producer could conceivably charge a higher-than-competitive wellhead price to the pipeline, thereby making excessive profits, and the pipeline might in turn try to pass the excessive prices it paid for gas through to its customers as a cost it had incurred. Note that even competitive wellhead markets would not eliminate these incentives.

Although one possible solution would be to prohibit pipelines and producer affiliates in the same wellhead markets, one should not leap from this warning to a proposal for disintegration. After all, there are a number of potential economic efficiencies that may be gained by vertical integration, including possibly the opportunity for affiliated firms to share risks and negotiate contracts in a less costly fashion. The point of the argument is simply to indicate that at the minimum some problems of a regulatory nature may remain under the NGPA.

In particular, the incentives for inefficiency we have described under vertical integration might be controlled if the pipeline regulator could recognize and disallow any excessively high prices charged by a producer affiliate — prices exceeding those charged by nonaffiliated producers. The drawback here is evident: the regulator would have to be watchful, and the task would not be easy, since as we have shown, gas contract provisions can be quite complicated.

## CONCLUSION

The natural gas industry has been neither completely regulated nor deregulated at the wellhead since 1938. Between The Natural Gas Act of 1938 and the *Phillips* decision of 1954, the statutory basis for such regulation was evidently in place, but it was not until the *Phillips* decision that regulation was enforced. Even then intrastate wellhead prices were uncontrolled, and there were serious administrative problems in regulating interstate prices. The best evidence available suggests that regulators had no real effect in holding interstate wellhead prices down below the levels that would have prevailed in the absence of regulation, at least until about 1970. During the 1960s no shortages were evident, and wellhead prices in interstate markets were approximately the same as the prices in the uncontrolled intrastate markets.

When the 1970s arrived, however, with a rising demand for energy and increased world oil prices, the FPC did hold interstate wellhead prices below the levels that would have been observed absent regulation. Shortages occurred. Natural gas reserves declined. The FPC was forced to let new gas prices rise to avert worse shortages. The clamor for deregulation of wellhead prices led to many proposals that were rejected amidst intense debate before the passage of the NGPA.

This new Act forms the framework for the deregulation of certain categories of natural gas at the wellhead. But deregulation is not complete. Old gas in interstate markets will not be deregulated, even after 1985. Neither will gas from stripper wells, from the Prudhoe Bay in Alaska, or from certain offshore areas.

It is not an easy task to analyze a piece of legislation that appears to have as many objectives as the NGPA. In one rather lengthy fell swoop it apparently seeks to promote efficiency in the use of energy resources, to provide at least a partial solution to the problem of gas shortages, to remove the incentives to dedicate new reserves only to intrastate markets wherever possible, to decrease reliance on imported energy, and to do all these things without large inflationary consequences.



We have concluded that the Act will lead to reduced shortages, both in the interim period and after 1985. The Act will lead to substantial improvements in the efficiency with which natural gas is used. However, it will not totally eliminate the old incentives for inefficiency, and it has introduced some new incentives for inefficiency.

As a recent development in the post-NGPA period, we discuss the "contracts problem" of the early 1980s. With the phased decontrol embodied in the NGPA, many individual producers and pipelines entered into long-term contracts in that period expecting high world oil prices and demand for natural gas in the future. Because of price controls still in effect, pipelines could not compete for additional supplies with higher prices, and instead offered non-price concessions to producers. With the collapse of world oil prices, the inflexibility in the contracts because of these concessions led to inefficiency in pipeline purchases and fears that some pipelines might go bankrupt. Policy proposals to deal with such contract problems must distinguish between poor contracting practices and the more general difficulty of negotiating long-term contracts under conditions of uncertainty.

Finally, two areas in which current developments in the gas market are taking place are the increased interest in spot markets in natural gas and proposals for vertical integration of producers and pipelines. With respect to the former, the development of a well-functioning spot market would facilitate the operation of futures markets, greatly increasing the flexibility of adjustments in long-term contracts. Vertical integration in response to recent contract difficulties between pipelines and producers is not without its problems, however, because of potential supra-normal transfer payments between affiliated producers and pipelines, even though the supply at the wellhead is competitive. Close scrutiny by pipeline regulators will be required.

## NOTES

[1]This legislation became effective in November 1978.

[2]For example, in a 1981 study Loury estimated that gross transfers from decontrol (in 1981 dollars) would rise from $9 billion in 1981 to $37 billion in 1984.

[3]Gas found in conjunction with oil is termed "associated gas."

[4]See, for example, *Information On Contracts Between Natural Gas Producers and Pipelines Companies*, Report of the Comptroller General of the United States, GAO/RCED-83-5, February 22, 1983.

[5]See, for example, *Barrett v. Kansas Natural Gas Co.*, 265 U.S. 298 (1924).

[6] *Natural Gas Act*, 52 Stat. 821 (1938), 15 U.S.C.A. et. seq., Section 1(a). No particular market failure or other problem was cited, however.

[7] *Ibid.*, Sections 4(a) and 4(b).

[8] *Ibid.*, Sections 4(c) and 4(d).

[9] *Ibid.*, Section 4(e).

[10] *Ibid.*, Section 1(c).

[11] *Phillips Petroleum Company v. Wisconsin et al.*, 342 U.S. 672 (1954).

[12] MacAvoy (1970a) p. 154.

[13] Kahn (1971), Vol. 11, p. 31.

[14] If there were no market imperfection or, particularly; no significant monopoly power, there could be no efficiency gain from the regulation.

[15] *National Gas Survey* (1975), Vol. 1, p. 85.

[16] See *In re Phillips Petroleum Company*, 24 FPC 537 (1960).

[17] This justification was suggested by Kahn (1970), Vol. 1, p. 43.

[18] *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968).

[19] *Federal Power Commission Annual Report* for 1974, p. 41.

[20] In fact, the table suggests that intrastate prices may have actually been less than interstate prices before 1970, although they were virtually the same.

[21] *The Economics of the Natural Gas Controversy*, Staff study of the Subcommittee on Energy of the Joint Economic Committee, Congress of the United States, September 19, 1977, p. 16.

[22] See, for example, *An Analysis of the Impact of the Projected Natural Gas Curtailments for the Winter of 1975–76*, a report of the Office of Technology Assessment, November 4, 1975.

[23] United States House of Representatives, Report No. 94–732, p. 6.

[24] Specifically, in the 1964–1969 period, additions to interstate reserves were 11.4 Tcf, while additions to intrastate reserves were 5.6 Tcf. In the 1970–1973 period, the corresponding additions were respectively 0.7 and 8.4 Tcf. See the *House of Representatives, Report No. 94-732* (94th Congress, 1st Session), p. 56.

[25] This simple calculation supports the more detailed study of MacAvoy and Pindyck (1975), who also measured an income transfer in excess of a billion dollars annually in 1975.

[26] This analysis assumes competition in gas supply.

[27] As a technical point, the use of consumer surplus exactly measures the welfare change for an individual if there are zero income effects associated with the demand schedule. However, Willig (1976) has shown that even if there are nonzero income effects, the measure may serve to approximate the actual welfare change.

[28] For a more detailed critique of the MacAvoy and Pindyck approach, see Braeutigam (1978).

[29] See, for example, MacAvoy (1970a), p. 160. Note that if monopsony were the principal problem, minimum rather than maximum wellhead prices might be set.

[30] For a more extensive discussion of wellhead market structure in the 1970s, see Braeutigam (1978).

[31] See Title III of the NGPA.

[32] This incentive for inefficient gas utilization due to weighted-average pricing is similar to that observed under the "entitlement system" accompany crude oil price controls; see the discussion in Case 4.



[33] For more on this point see *Pricing Provisions of the Natural Gas Policy Act of 1978*, Energy Policy Study, Vol. 3, Energy Information Administration of the Department of Energy, pp. 15–17.

[34] An extended discussion of contracting and deregulation is available in U.S. Energy Information Administration (1981–1983a, 1983b). A discussion of related legal issues can be found in Pierce (1983).

[35] A major source of uncertainty here is variation in the price of oil, a substitute for gas for many users.

[36] See the theoretical discussions in Hall and Lilien (1979) and Hubbard and Weiner (1984).

[37] In formal econometric tests, Hubbard and Weiner (1984) found that the effect of the price ceilings was to raise the average take-or-pay requirement by about 5 percentage points. While this represents a significant increase, take-or-pay requirements are predicted to be large even in contracts for gas not subject to price controls.

[38] Descriptions of the bills are contained in U.S. Energy Information Administration (1983b).

[39] The world oil market, for example, operates on a two-price system, with trades carried out both under long-term contracts and spot market transactions.

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# CASE 6

# The Partial Deregulation of Banks and Other Depository Institutions

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## INTRODUCTION

Commercial banks and other depository institutions — savings and loan associations, mutual savings banks, and credit unions — are extensively regulated by the federal government and by the fifty state governments. They may be the most heavily regulated institutions in the American economy after electric utilities.

Depository institutions are subject to both economic regulation and "social" regulation, and both forms of regulation have substantial consequences for the performance of this industry. The economic regulation includes federally imposed limits on the interest rates they can pay on various kinds of deposits (price controls), state-imposed limits on the interest rates they can charge on some types of loans (price controls), state and federally imposed limits on who can establish new banks and other depository institutions or even branches of existing institutions (entry controls), and federally imposed limits on the activities (financial and nonfinancial) in which these institutions can engage (entry controls). The social regulation includes government efforts to ensure that these institutions are safe, that they pro-

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