MASTER

THE REGULATION AND DEREGULATION OF NATURAL GAS IN THE U.S. (1938 - 1985)

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Section One. Introduction.

Public policy towards natural gas has swung first towards, and then away from regulation in this century. In 1906, the Congress specifically excluded natural gas from the jurisdiction of the Interstate Commerce Commission. Three decades later, a New Deal Congress passed the Natural Gas Act of 1938 bringing pipelines under the control of the Federal Power Commission (FDC).[1/] Forty years thereafter, the Congress passed a phased decontrol bill, the Natural Gas Policy Act (NGPA) of 1978, as part of the Carter Administration's National Energy Plan.

Recently, the Congress has backed off from New Deal legislation in other markets--notably aviation and trucking. In this study, we examine the rise and fall of economic regulation in the natural gas industry to understand: (1) why public policy has followed a pendulum's path, and (2) the economic consequences of regulation and deregulation. The main part of the analysis is directed toward the Natural Gas Policy Act of 1978. Widely viewed as a deregulation measure, we find that the Act is more restrictive and burdensome than the pricing policies it superceded. The path toward deregulation in natural gas and perhaps other markets is not as direct or simple as might be expected.

The shifting course of public policy is explained in part by two, often conflicting, motivations for regulation: efficiency and redistribution. The Natrual Gas Act of 1938 followed shortly after a Federal Trade Commission study documented the rising concentration of ownership in the pipeline market and significant vertical integration. The initial impe-

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1/ Now the Federal Energy Regulatory Commission (FERC).

tus for federal regulation of natural gas was primarily to improve the performance of the market. The Federal Power Commission, which administered the Act, became over the years "captured" by matters of allocation and redistribution between customer groups. The Commission increasingly came to view its role as to protect consumers from price increases, and later to allocate the resulting shortages in favor of residential and commercial customers.

The Commission seemingly lost sight of the basic economic fact about natural gas--that it is an exhaustible resource. As such its supply decreases over time, and in an efficient market the price of gas will rise relative to other commodities in order to encourage production from high priced reserves, while promoting conservation on the demand side. In an efficient market, depletable resource rents increase over time. The FPC's concern with redistribution goals, as well as a certain inevitable bureaucratic inertia, prevented the field price of interstate gas from increasing and ultimately created a shortage.

The Natural Gas Policy Act of 1978 could have alleviated the FPC induced shortage by lifting wellhead price controls, but this would have transferred rents away from residential and commercial customers who had long benefitted from FPC pricing and curtailment policies. The complex compromise that produced the NGPA is best understood as an attempt by Congress to allow prices to rise to more efficient levels without hurting small consumers.

In attempting to deregulate the natural gas market without hurting the consumer groups that had benefitted from pre-existing regulation, the Congress produced an Act which finds meager success in the achievement of either efficiency or equity goals. In many respects, the Act pushes the scope and restrictiveness of gas regulation beyond the prior FPC policies. Thus the natural gas industry dramatically illustrates the dangers and difficulties of deregulation.

Section Two. Natural Gas Regulation Prior to the NGPA.

At several points in the history of gas regulation the scope of federal regulation underwent abrupt change:

(1) The Natural Gas Act of 1938

(2) The Phillips Petroleum Case in 1954

(3) The onset of curtailments in 1970/71

(4) The enactment of the Natural Gas Policy Act in 1978

These signal events demarcate four periods, prior to the NGPA, in which the evolution of natural gas policy can be analyzed. In each period the division of rents between producers, pipelines, distributors and consumers was markedly shifted. The historical approach is used to show how and why regulation e-volved as it did in the natural gas market, and who benefitted.

2.1 The Unregulated Period

Natural Gas was a negligible part of the U.S. energy picture before World War II, comprising only 4% of primary energy consumption as late as 1920. Natural gas only became a national industry with a widespread market after the technology for building high pressure pipelines, from the fields in the South-central part of the country to the major markets in the East and Midwest, was developed.

Without the means to economically move gas, the customers of the natural gas industry were predominantly large industrial boiler users located near gas wells. In the years prior to World War II, low BTU "coal" gas, made from the destructive distillation of coal into carbon monoxide, hydrogen, and other organic products, served more customers and sold more volume than natural gas. This manufactured gas replaced candles for residential and commercial customer illumination. Manufactured gas, unlike natural, was relatively expensive and environmentally unsound. Thus residential and commercial illumination customers presented a ready-made market opportunity for cheap natural gas once significant long-distance pipeline construction began in the early twentieth century.

Unlike the manufactured gas industry, which achieved high asset utilization on production for predictable illumination demands, natural gas production often followed a boom/bust cycle before the Natural Gas Act of 1938. Early state attempts to regulate the field market sought to control flaring, rapid depletion, and other wasteful field practices. State controls of this sort were upheld by the Supreme Court; however, the Congress continued to support a free market in the natural gas industry. In 1906 the Congress specifically excluded interstate pipelines from the jurisdiction of the Interstate Commerce Act.

The absence of rate regulation in natural gas stands out in distinct contrast to the experience of the railroad industry under Interstate Commerce Commission controls. In a series of cases from West (Attorney General of Oklahoma) v. Kansas Natural Gas Company in 1911 to Champlin Oil Refining Company v. Corporation Commission of Oklahoma in 1932, the Supreme Court consistently restricted State authority to the prevention of wastage and the sale of intrastate gas. Interstate pipeline companies were free to set prices to out-of-state customers and resellers.

The two "capture" theories of Commission regulation--that regulation either serves to prop up industry profits or to protect consumers from unfair pricing--may explain the absence of natural gas regulation until 1938. Both theories have been put forth as an explanation for the regulation of railroad rates by the Interstate Commerce Commission following the passage of the Interstate Commerce Act in 1887.[1/] In the first two decades of the twentieth century, gas consumption was not widespread among residences and small commercial establishments. Predatory pricing and depressed profits were not characteristic of the gas pipeline industry (in part because ownership was increasingly concentrated both vertically and horizontally). It was in fact the potential anti-competitive consequences of concentration which was the primary motivation for the Natural Gas Act of 1938.

2.2 The Natural Gas Act of 1938

Congressional attitudes toward natural gas regulation began to change in the merger wave of the 1920's as the ownership of pipelines and gas utilities became concentrated in a few holding companies. In 1928 the Senate directed the Federal Trade Commission to study concentration in the gas and electric utilities. The 1935 FTC Report demonstrated considerable vertical integration of ownership between gas production and transmission and the resultant power of the holding companies to squeeze independent producers in some gas producting regions. Consumer interests may have also motivated the Natural Gas Act of 1938. As the interstate pipeline system expanded, increasing the importance of municipal gas customers, political support for pipeline regulation increased. Some cities, especially in the Midwest, felt that they were unfairly denied access to cheap natural gas, others complained of price discrimination.

1/ The view that railroad regulation benefitted the railroad companies by eliminating price warfare is expounded by Gabriel Kalko in Railroads and Regulation; while the orthodox view that railroad regulation was motivated by the political power of farmers and eastern shippers is argued by Albro Martin in Enterprise Denied.

Organizations such as the Alliance of Cities and the U.S. Conference of Majors urged federal control over the rates interstate pipelines charged municipal distribution companies. Municipal interests were reflected in the principal provisions of the Act. The FPC was given jurisdiction over pipeline rates and the certification of new facilities. The FPC also controlled abandonments of pipline service.

The Congress decided that the field price of natural gas should be left to the States to regulate while pipeline rates would be the jurisdiction of the Federal Power Commission. Section 1(b) accordingly excluded the "production or gathering of natural gas" from the jurisdiction of the Act, and for sixteen years the FPC and the Supreme Court, in a half dozen cases, concurred in this interpretation.

But Congress had failed to foresee adequately the consequences of the Natural Gas Act. The States were able to offset the affect of the FPC on the distribution of gas rents between consuming and producing states. Producing states imposed the equivalent of tariffs and export restrictions on field gas to increase revenues collected from consuming states and to reduce out-of-state movement of gas. The intent of the Natural Gas Act could only be effectuated by extending federal control of natural gas to the field market. In Phillips Petroleum Company vs. State of Wisconsin (1954) the Supreme Court reversed itself, and held that FPC rate-making jurisdiction extended into the field market for natural gas.

2.3 Well-head Price Regulation

The Natural Gas Act of 1938 established interstate pipeline rate regulation, which had a plausible economic rationale, and seemingly shifted some of the rents associated with gas production to the consuming states.

The regulation of pipeline rates caused distortions in the intrastate market which ultimately led to increased federal intervention to achieve greater control over the interstate sale of gas. Professor McKie has termed this the "tar-baby" effect: when regulation expands to patch up self-induced distortions and unintended consequences. As we shall see, well-head price regulation under the FPC, following the Phillips Petroleum Case, resulted in further unforseen effects on the interstate gas market--severe shortages and customer curtailments.

The case for producer regulation on the basis of supposed monopoly power was never compelling. In the most careful analysis of the field markets, MacAvoy conclusively showed that pricing behavior prior to Phillips was consistent with a mixture of competition and pipeline monopoly (i.e., monopsony) power.[1/] Simple concentration ratio measures of the market power of buyers and sellers of new natural gas for reserves in regional markets have shown that concentration is greater among the pipelines purchasing new gas contracts.[2/] This pattern of market structure results from the fact that gas fields comprising numerous small gas producers are frequently connected to only one or two interstate pipelines. Even if the situation were reversed, with high producer and low buyer concentration, the ease of entry into gas production would effectively limit monopoly power.[3/]

1/ MacAvoy, Paul. Price Formation in the Natural Gas Fields. 1960.

2/ Breyer, S. and P. MacAvoy. Energy Regulation by the Federal Power Commission. 1974.

3/ This point is made by James McKie. "Market Structure and Uncertainty in Oil and Gas Exploration," Quarterly Journal of Economics (Vol 74, 1960), and cited in Breyer and MacAvoy.

Even if federal regulation of well-head prices had a sound economic rationale, the implementation of well-head price regulations for the several thousand independent gas producers caused unprecedented administrative difficulties which completely overwhelmed the FPC staff. Initially the FPC attempted to implement producer rate regulation by applying traditional cost-of-service utility regulation to the 3,000 individual producers extant in 1954. Such a system seemingly would eliminate producer rents. However, the FPC soon found that utility-type regulation was inapplicable to natural gas producers for several reasons: (1) the joint costs of associated (oil and gas) producers could not be allocated objectively, (2) allocation of and compensation for exploration costs from years prior to field production was similarly complicated, (3) no satisfactory system for allocating pipeline rights to relatively cheap gas was ever devised (such as the oil refinery entitlements program), and (4) the risks of new exploration were not taken into account by conventional utility rates.[1/] Individual producer rates were an administrative nightmare. By 1960 there were 3,278 rate filings waiting decision.[2/]

The Commission then turned to a system of area rates in five geographic regions under its Statement of General Policy published in 1960.[3/] Provisional prices were established for gas under new and existing contracts. Such a two-tier system might have been used to efficiently transfer producers' windfall profits to consumers and pipelines had the FPC

1/ Breyer and MacAvoy.

2/ Natural Gas Survey. p. 85.

3/ Codified as 18 C.F.R. §256 and cited in the Natural Gas Survey.

allowed new contract prices to rise to a competitive level; however, implementation was so slow that prices were effectively frozen throughout the 1960's.

The first case decided under the area rate regulation concept was the Permian Basin Area Rate completed in 1968. In all, six area rate cases were decided and affirmed between 1968 and 1974, each involving substantial litigation. As a result of the Atlantic Refining Company v. Public Service Company of New York case (1959),[1/] the Commission followed the "in-line" pricing guideline to determine the reasonableness of rate applications. The effect of this policy was that no contracts for existing reserves were approved at prices higher than the average for the area, and no new contracts were approved at prices above the pre-existing maximum. The logical consequences of in-line pricing are that the historic maximum rate becomes the price ceiling, that the average contract price creeps upward very slowly, so that with the slow disposition of area rate cases, rates will reflect cost conditions which are years out of date.

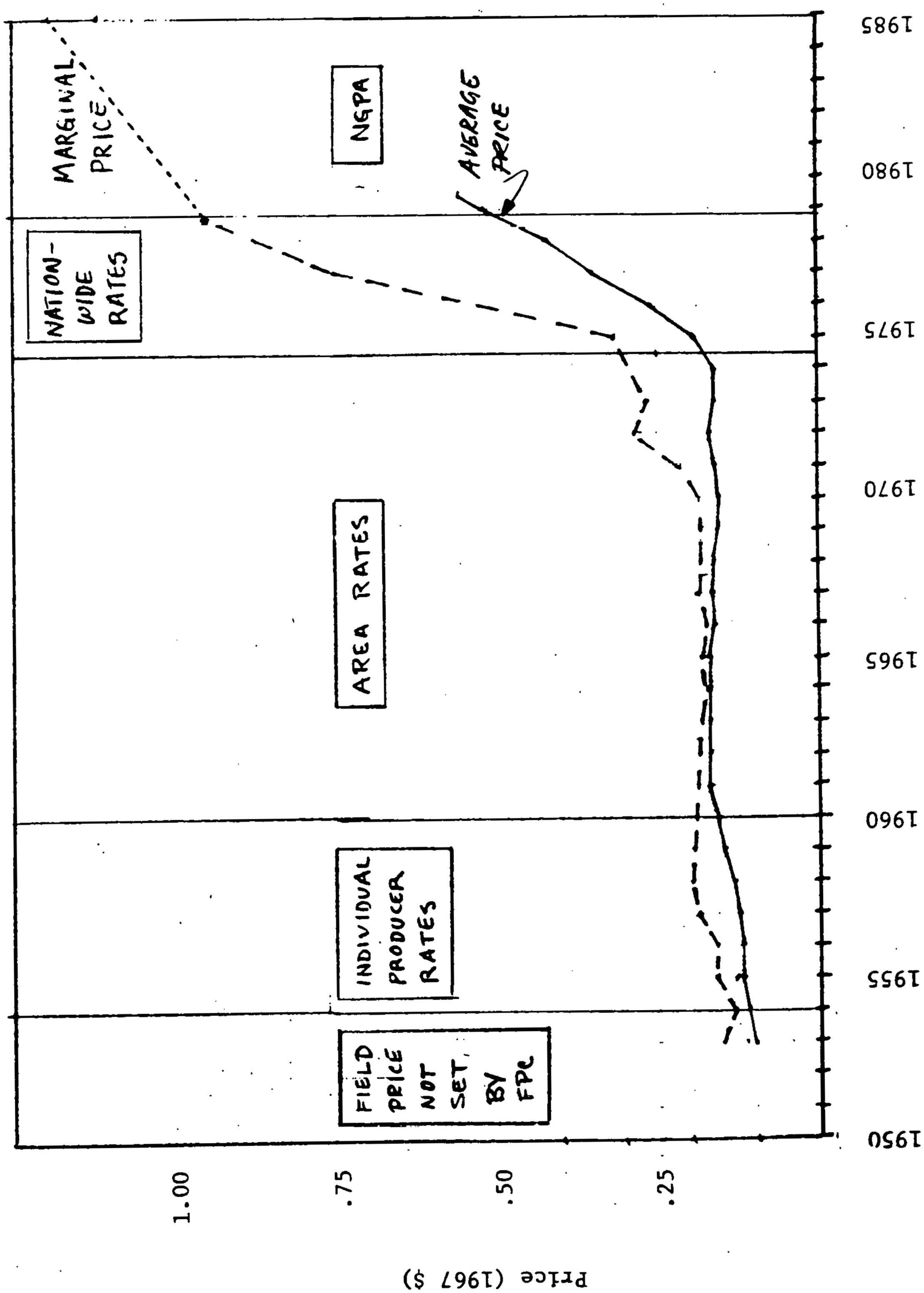
Figure 2.1 shows the marginal and average price paid by interstate pipelines to domestic gas producers, measured in 1967 dollars.[2/] During the first ten years of area rates, from 1960 to 1970, FPC rate regulation prevented any rise in the marginal price of gas at the well-head. The fundamental law of depletable resources--that their market price rise relative to other commodities over time--was violated. Not until firm

1/ 360 U.S. 378. Cited in the Natural Gas Survey.

2/ Nominal prices are deflated by the wholesale price index (WPI) for all commodities.

Figure 2.1

MARGINAL AND AVERAGE INTERSTATE PRICE OF NAUTRAL GAS (1967 $)



gas customers were curtailed by 100 Bcf in the winter of 1970/71 did the FPC grant price increases for new gas committed to the interstate system.

How can the pricing policy of the FPC be explained? Formerly, the FPC established area rates for the field price of natural gas on the basis of production costs. However, the evidence on gas exploration and discovery clearly indicates that domestic gas and oil producers were at the intensive margin of production--more dry holes were drilled for each successful well, and the average size of the gas fields discovered was declining each year. Table 2.1 shows that the percentage of gas wells yielding recoverable reserves had declined from 11.3% (1945-1954) to 10.9% (1955-1964) while the percentage of significant finds (over 6 Bcf of gas recoverable) among these successful wells had fallen even more sharply from 36.2% to 21.9%. The failure of the FPC to raise the price for new gas dedicated to the interstate market in the first ten years under area rate-making rules indicates a phenomenon which has been called "regulatory lag." Regulatory lag is the discrepancy between allowed prices and current production cost conditions which arises when rates are set infrequently on the basis of historic cost data. Regulatory lag is more severe when the time interval between rate cases is long and when unanticipated cost escalation is large. While regulatory lag has been justified as a spur to productivity in the electric utility industry,[1/] the argument is clearly inapplicable to an extractive industry at the intensive margin of production.

1/ W. Baumol and A. Klevorick. "Input Choices and Rate of Return Regulation: An Overview of the Discussion."

TABLE 2.1

NATURAL GAS DISCOVERIES

YEAR	PERCENT OF WELLS SUCCESSFUL[1/] (OIL AND GAS)	PERCENT OF SUCCESSFUL GAS WELLS SIGNIFICANT[2/]	PERCENT OF OIL WELLS SIGNIFICANT[3/]
1945	11.3	41	4.6
1946	10.6	33	3.5
1947	11.2	37	4.1
1948	11.7	34	4.0
1949	11.4	40	4.6
1950	11.2	34	3.8
1951	11.1	38	4.2
1952	11.1	37	4.1
1953	11.2	27	3.0
1954	12.2	41	3.0
AVERAGE	11.3	36.2	3.9
1955	11.3	19	2.1
1956	9.9	26	2.6
1957	10.9	26	2.8
1958	11.3	38	4.3
1959	11.0	19	2.1
1960	10.2	15	1.5
1961	10.8	16	1.7
1962	11.6	15	1.7
1963	11.7	21	2.5
1964	10.0	24	2.4
AVERAGE	10.9	21.9	2.4
1965	10.2	22	2.2
1966	10.3	20	2.1
1967	10.3	NA[4/]	NA[4/]
1968	8.6		
1969	9.0		
1970	9.7		
1971	9.7		
1972	11.1		
1973	14.0		
AVERAGE	10.3	21.5	2.2

Source: Natural Gas Survey. 1975. p. 234.

1/ Successful wells are those not classified as "dry holes."

2/ Significant gas wells are those with more than 6 BCF of recoverable reserves.

3/ (% all wells significant) = (% successful gas wells significant) X (% wells successful).

4/ Wells are classified as significant six years after discovery.

Regulatory lag has the effect of transferring income from gas producers to gas pipelines, distributors and end-use customers. Given that gas consumers far outnumber gas producers and their Congressional representatives, such redistribution was politically expedient. The evidence suggests that in the first ten years of area rates the FPC weighed redistribution objectives more heavily than efficiency goals. This conclusion is based on the fact that the FPC held down the price of both old and new gas reserves. Had the price of new gas been allowed to rise at a rate reflecting marginal production costs supply incentives would have been minimally blunted while consumers kept the infra-marginal rents associated with low priced old gas. Figure 2.1 shows that while the price of new gas was slightly higher than old gas, the FPC did not allow new gas prices to rise from 1960 to 1970. The FPC probably avoided creating a large gap between old and new gas because of the apparent inequities this would cause between pipelines and distributors with differential access to cheap sources of old gas.

The pricing behavior of the FPC is consistent with the hypothesis that the FPC acted to maximize short-run political support by emphasizing redistribution at the expense of efficiency in the interstate gas market. This behavior is entirely consistent with the Peltzman-Baldwin view that regulatory and public agencies attempt to distribute benefits (and losses) so as to maximize net political support for their actions.[1/] This objective ordinarily means visibly benefitting the many at the expense of the few, within the short time horizon in which political goals are cast.[2/]

1/ S. Peltzman.

2/ J. Baldwin. The Regulatory Agency and the Public Corporations. 1975.

2.4 The Curtailment Period

The shortage of natural gas in the interstate market first became evident in the reserves which back up production. The FPC recommended reserve backing is 20 times production. The level of backing in the unregulated intrastate market has never fallen below 12 in the period from 1964-1977, and the average reserve-to-production ratio was 14.4. Table 2.2 shows that by either the FPC or the unregulated market criteria, a shortage of backing for interstate production had developed by 1969. Interstate reserves peaked in 1967, and the reserve-to-production ratio deteriorated from 18.9 in 1964 to 8.5 in 1977. Over the 1964-1977 period interstate reserves dropped by half: from 189 trillion cubic feet (Tcf) to 93 Tcf; in the intrastate market reserves increased slightly from 92 to 115 Tcf, and the reserve backing did not comparably deteriorate.

The shorage occurred not only because the FPC held down the price of new gas in the interstate market, but because the price was higher in the unregulated intrastate market. The first effect is the direct elasticity of supply, in the interstate market, and the second effect is the cross elasticity of supply between the inter and intrastate markets. The direct effect works to lower the level of exploration activity, while the cross effect shifts the proportion of new gas dedicated between the inter and intrastate markets.

The influence of both the cross and direct elasticities of supply are reflected in Table 2.3.

YEAR	INTERSTATE MARKET				INTRASTATE MARKET			
	RESERVE ADDITIONS (Tcf)	PRODUCTION (Tcf)	YEAR-END RESERVES (Tcf)	RESERVES TO PRODUCTION RATIO	RESERVE ADDITIONS (Tcf)	PRODUCTION (Tcf)	YEAR-END RESERVES (Tcf)	RESERVES TO PRODUCTION RATIO
1964	10.6	10.0	189.2	18.9	9.7	5.4	92.1	17.1
1965	13.3	10.4	192.1	18.5	8.0	5.9	94.2	16.0
1966	14.2	11.1	195.1	17.5	6.0	6.4	93.9	14.7
1967	14.8	11.8	198.1	16.8	7.0	6.6	94.3	14.3
1968	9.5	12.6	195.0	15.5	4.2	6.8	91.7	13.5
1969	6.1	13.4	187.6	14.0	2.3	7.3	86.8	11.9
1970	0	14.1	173.6	12.3	37.2	7.9	116.0	14.7
1971	2.0	14.2	161.3	11.4	7.8	7.9	116.0	14.7
1972	(0.2)	14.2	146.9	10.3	9.8	8.3	117.5	14.2
1973	1.1	13.7	134.3	9.8	5.7	8.9	114.3	12.8
1974	(0.8)	13.0	120.5	9.3	9.5	8.3	115.5	13.9
1975	(1.7)	12.0	106.8	8.9	12.2	7.7	120.0	15.6
1976	2.9	11.4	98.2	8.6	4.7	8.1	116.7	14.4
1977	5.5	10.9	92.9	8.5	6.4	8.5	114.5	13.5

Table 2.2 CHANGES IN GAS RESERVES IN THE INTER- AND INTRA-STATE MARKETS

Source: U.S. D.O.E. Gas Supplies of Interstate Natural Gas Pipeline Companies -- 1977. June, 1979.

YEARS	AVERAGE ANNUAL INTERSTATE RESERVE ADDITIONS		AVERAGE ANNUAL INTRASTATE RESERVE ADDITIONS		AVERAGE ANNUAL TOTAL RESERVE ADDITIONS	
	(Tcf)	PERCENT	(Tcf)	PERCENT	(Tcf)	PERCENT
1964-69	137.0	64.8%	74.4	35.2%	211.4	100%
1970-77	12.6	8.6%	33.3	91.4%	145.6	100%

TABLE 2.3 RESERVE ADDITIONS IN THE INTER- AND INTRA-STATE MARKETS

From 1964 to 1969, two-thirds of all new reserves were dedicated to the interstate market, in about the same proportion as the initial level of reserves in 1964. In 1970-77, however, over 90 percent of new reserves[1/] were dedicated to the intrastate market whereas 60 percent of initial reserves, in 1970, were in the interstate system. A direct effect is also indicated by the decline in the average annual rate of new reserve additions to both markets from 211.4 Tcf/year (1964-1969) to 145.6 Tcf/year (1970-1977).[2/] The curtailments which developed in 1970/71 were inevitable under the FPC area rate policy, although the timing was undoubtedly accelerated by a number of factors on the demand side of the equation. Stringent air quality standards which became effective in the early 1970's increased the attractiveness of natural gas vis-a-vis high sulfur oil and coal in the interstate market. The real price of electircity began to rise by the end of the 1960's, after twenty years of decline, encouraging end-user substitution of gas for electricity. Table 2.4 shows the rise in curtailments from 1970/71 to the passage of the NGPA in 1978.

1/ Reserve additions include revisions and extensions of existing wells in addition to discoveries unrelated to existing producing wells.

2/ A Tcf is a trillion cubic feet or about one quadrillion Btu of natural gas.

TABLE 2.4 GAS CURTAILMENTS

YEAR (Apr.-Mar.)	ANNUAL EXCESS DEMAND[a/]	ANNUAL DEMAND[b/]	PERCENT DEMAND CURTAILED	PERCENT FIRM DEMAND CURTAILED[c/]	PERCENT INTERRUPTIBLE DEMAND CURTAILED[c/]
	(Tcf)	(Tcf)	%	%	%
1970-71	0.1[d/]	14.2	0.7		
1971-72	0.5[d/]	14.7	3.4		
1972-73	1.31[e/]	15.52[e/]	8.4[e/]		
1973-74	1.41	15.08	9.3		
1974-75	2.23	15.36	14.5	13.6	36.6
1975-76	3.20	14.81	21.5	19.7	54.8
1976-77	4.09	15.37	26.2	23.0	70.9
1977-78	4.04	14.64	26.9	23.1	66.9
1978-79	3.51[f/]	14.29[f/]	23.9	20.8	52.2

Source: FERC. Form 16 and Form 15.
EIA. Monthly Energy Review (12/1979).

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a/ Excess demand equals net pipeline curtailment (from Form 16) plus the volume of demand that permanently switched to alternate fuels because of curtailment (from Monthly Energy Review).

b/ Annual demand equals annual deliveries plus excess demand. Not that excess demand does not include the effect of hook-up moratoria.

c/ Excludes permanent fuel switching which is unavailable by customer class.

d/ From P. Bailey. "Gas Curtailment Priorities and Alternate Purchase Arrangements." ICF Incorporated. 1979.

e/ Data is for the 12 months from September to August.

f/ Assumes no change from 1977-78 in the volume of demand that permanently switched to alternate fuels.

The curtailment in the winter of 1970/71 caused the FPC to abruptly shift its pricing policies. The price of new gas contracts which had stood at 19¢/Mcf (1967$) for the previous ten years, was allowed to rise 3-5¢ in 1971 and increased to 28¢ in 1972 (see Figure 2.1). The Commission provided a number of exemptions from, and amendments to the area rate regulations which allowed the effective price of gas to rise without undermining ongoing court cases. Pipeline companies were allowed to include advance payments to producers (for development expenses) in the rate base for the computation of transmission charges. Consumers in effect paid the interest on these advance payments which added $2 billion to the pipeline rate base by 1975. The Commission adopted an "optional pricing" procedure which permitted shortage pipelines to freely negotiate long-term contracts with producers. The Commission also began issuing "limited-term certificates" which allowed producers to commit gas to the interstate market for short periods at prices above existing area rate ceilings. Thirty-one percent of the 1.1 Tcf of reserves dedicated to the inter-state market in 1973 was obtained by limited-term certificates.[1/] Optional pricing, limited-term certificates, and imports from Canada which comprised 5.4% of interstate gas supply in 1970 rose to 11.2% of supply in 1977 (see Table 2.5).

The various pricing loopholes did increase the price of new gas in the interstate market, but failed to staunch the swelling volume of curtailments (see Table 2.4). The FPC response was twofold: rules were promulgated for allocating pipeline curtailments in 1973, and the tattered area rate regulations were abandoned in favor of a new system of nation-wide rates in 1974.

1/ R.B. Helms. Natural Gas Regulation. AEI. 1974. p. 27.

YEAR	LIMITED TERM & EMERGENCY PURCHASES	INDEPENDENT PRODUCER	COMPANY OWNED	IMPORT CONTRACT PIPELINE	LNG	TOTAL INTER-STATE	PERCENT EMERGENCY & IMPORTS
1963		8.5	0.9	0.4		9.8	4.1%
1964		9.1	0.9	0.4		10.4	3.8
1965		9.4	1.0	0.4		10.8	3.7
1966		10.1	1.0	0.4		11.5	3.5
1967		10.8	1.0	0.5		12.3	4.1
1968		11.6	1.0	0.6		13.2	4.5
1969		12.4	1.0	0.7		14.1	5.0
1970		13.1	1.0	0.8		14.9	5.4
1971	0.18	13.1	0.9	0.9		15.1	7.3
1972	0.27	12.9	1.0	1.0		15.2	8.6
1973	0.29	12.6	0.8	1.0		14.7	8.8
1974	0.23	12.0	0.8	0.9		13.9	7.9
1975	0.11	11.2	0.7	0.9		12.9	7.8
1976	0.08	10.7	0.7	0.9		12.3	8.1
1977	0.16	10.0	0.9	1.1	0.1	12.1	11.2%

Table 2.5

Interstate Gas Supply (in TCF)

The curtailment priority system is yet another example of the tar-baby syndrome. The curtailments in the interstate gas market, caused by field price regulation, spawned a new set of regulations governing the allocation of the shortage among distribution companies. Nation-wide rate-making provided a mechanism for reducing regulatory log. The conflicting goals of redistribution (allocating shortage gas) and efficiency (allowing the price of new interstate gas contracts to rise) are embodied in these policies.

2.4.1 Curtailment Plans

Pipelines with substantial excess demand were confronted with the problem of allocating available supplies, over the course of the year, among distribution companies and direct industrial customers with firm contracts for gas deliveries. The abrogation of firm contracts resulted in a spate of legal actions. The FPC issued, in 1973, Order No. 467B which imposed a uniform procedure for determining pipeline curtailment priorities based on end-use categories. A nine tier priority schedule ranking end-use priorities from residential/small commercial to large interruptibles (Table 2.6) was used to determine deliveries to distribution companies. Distributor deliveries as of 1972 were classified according to curtailment priority, and gas was allocated from priority one down, until supplies were exhausted. Since the possibility of shortages had not been foreseen in the Natural Gas Act of 1938, and the FPC was provided no express powers for managing curtailments, Order No. 467-B was an exercise of extraordinary administrative discretion. Nevertheless, the Supreme Court upheld this taking of property rights writ large, and has only infrequently required compensation paid between distributors.

Curtailment plans result in substantial transfers of wealth between the nine customer groups receiving varying levels of Commission favor, and between distribution utilities gaining and losing volume. Litigation brought by distributors, customers, and pipelines has greatly delayed the completion of approved plans. In the case of the Transco pipeline, eight years of appeal, remand, and redecision failed to produce a final curtailment plan. Adding to the confusion of pipeline curtailment plans, the states retain jurisdiction over the allocation of gas sold by distribu-

PRIORITY	CUSTOMER CLASS	VOLUME (Mcf/day)
1.	Residential and Small Commercial	less than 50
2.	Large Commercial	more than 50
	Feedstock, process, and storage injection	
3.	Other Industrial Requirements	
4.	Firm Industrial Boiler Use	1500 to 3000
5.	Firm Industrial Boiler Use	more than 3000
6.	Interruptible	300 to 1500
7.	Interruptible	1500 to 3000
8.	Interruptible	3000 to 10,000
9.	Interruptible	more than 10,000

Table 2.6 Curtailment Priorities Pursuant to FPC Order No. 467-B

tion utilities; therefore, two layers of curtailment authority separate pipeline gas from ultimate customers. A 1975 survey by the FEA showed that seventeen of the twenty-one states studied followed FPC end use priorities approximately, while four curtailed all large users (commercial and industrial) on a pro rata basis after meeting residential demand.[1/] This complex system of curtailment not only involves heavy administrative costs, but imposes a real economic loss since allocation is determined by end use category rather than actual end use value of natural gas.

1/ U.S. FEA. National Energy Outlook. 1976. p. 123.

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The curtailment policy did allow the Commission to continue its longstanding policy of redistributing rents from interstate producers to the many small residential and commercial customers. The FPC could continue to hold the price of new gas contracts below the market clearing level, while protecting small consumers at the top of the priority queue from curtailments.

1/ U.S. FEA. <u>National Energy Outlook</u>. 1976. p. 123.

2.4.2 Nationwide Ratemaking

The FPC adopted nationwide producer rates in June 1974. Opinion No. 699 established a one-tier national rate of 42.0¢/Mcf with 1.0¢/Mcf annual escalation through 1975. Thereafter, national rates were to be revised every biennium (two years). Ostensibly the purpose of nationwide rates was to reduce regulatory lag to two years. This would ameliorate the pernicious affect of the decade long lag that had developed under area rates.

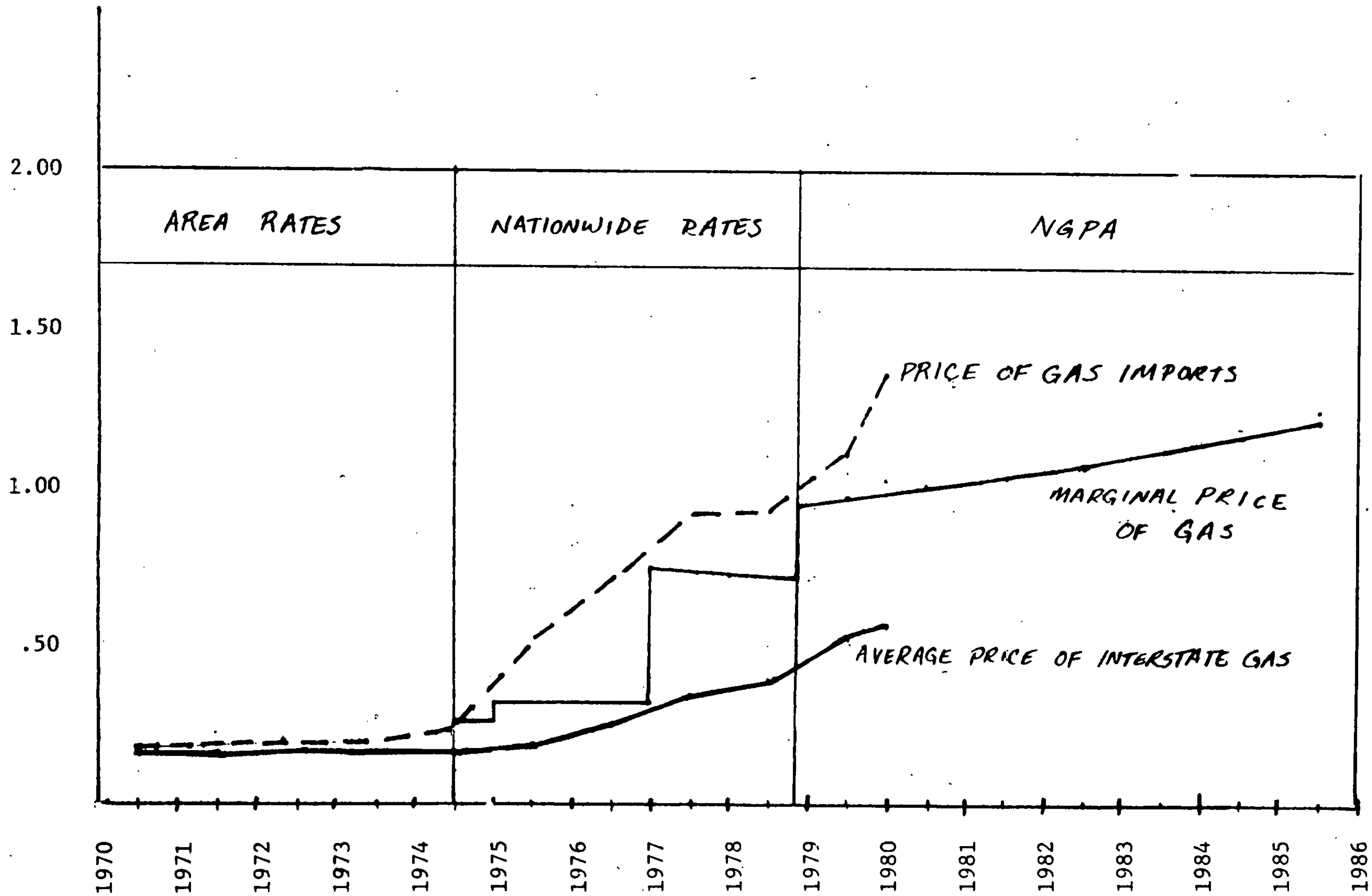
Figure 2.2 compares the allowed price of new gas to the price of Canadian imports, a measure of the unregulated price of gas. During the period of nationwide rates (1974-1978) a clear pattern of two-year lag is visible.

As initially issued, nationwide producer rates demonstrated a startling reversal in FPC policy: the two-tier pricing approach of area rates was abandonned. The Commission had evidently embraced the goal of efficiency and adopted a supply oriented pricing policy to eliminate curtailments. If the nationwide producer rate policy had maintained one-tier rates, billions of dollars of rents would have been transferred from gas consumers to infra-marginal producers. The Commission raised the price of gas to 52¢/Mcf at the start of the 1975-76 biennium, and raised the price again to $1.42/Mcf at the beginning of the 1977-78 biennium. The jump to $1.42 corresponded with prices in the unregulated intrastate markets and the price of Canadian imports (see Figure 2.2); however, the rate increase was so large (170%) and sudden that the Commission backed down and re-established two-tier pricing.

Nationwide producer rates did succeed in attracting new reserves to the interstate market. Annual reserve additions averaged only .4 Tcf from

Figure 2.2

NATIONWIDE RATES (1967 $)



the onset of curtailments in 1970 to the issuance of the nationwide rate policy in 1974. After Opinion No. 699, reserve additions averaged 2.2 Tcf/year (see Table 2.2). The field price of natural gas did not, however, rise sufficiently to equilibrate supply and demand in the interstate market. Curtailments exceeded 25% of requirements in 1976/77, and curtailment policy was confounded by countless inequities and legal complications.

2.5 Summary

When the Carter Administration sent the National Energy Plan to Congress in April 1977, the interstate gas market was in disarray. Curtailment plans proved a legal nightmare; shortages burdened industrial planning and operations; and hook-up restrictions had been enacted in all but sixteen states.[1/] The dilemma resulted from the twin operation of regulatory lag in the area rate proceedings--that bureaucratic inertia which prevented prices from keeping pace with changing cost conditions--and the tar-baby effect whereby distortions are resolved by further regulatory expansion.

At base, public policy toward natural gass suffered from a conflict of goals: the simultaneous desire to (1) protect small interstate consumers from the inevitable price increases associated with a depleting resource, and (2) to provide incentives for the efficient utilization of and exploration for natural gas. Under area rate regulation it seemed that redistribution, from inframarginal producers to consumers, could be accomplished without any immediate harm to supply. Indeed, new reserve additions dropped sharply only after 1969, although the reserve to production ratio began a long decline some five years earlier. When persistent shortages emerged in the early 1970s, the Commission chose the short-term expedient of a curtailment policy biased in favor of small residential and commercial customers, while it vacillated in its determination to allow field prices to rise to market clearing levels. While the FPC did permit the new price of natural gas to rise substantially, in two-year intervals, the reimposition

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1/ U.S. FEA. National Energy Outlook. 1976. p. 115.

of two-tier pricing reduced the effectiveness of these incentives. Producers could reasonably anticipate that new gas reserves would at some point be subject to fixed "old gas" rates. For any level of new contract prices allowed by the FPC, the anticipation of new vintage price controls truncates the rate of return expected from exploration and diminished drilling for non-associated gas wells.

When the Congress undertook consideration of a new natural gas policy, the ongoing energy crisis demanded that efficiency in conservation and production receive due attention. On the other hand, residential and small commercial customers, who had long benefitted from low prices and a secure position in the curtailment queue, represented a politically influential group opposed to changes in the terms of regulation. The Natural Gas Policy Act was an immensely complicated compromise between these opposing interests, with uncertain consequences for the natural gas market.

Section 3. Politics and Provisions of the NGPA.

The Natural Gas Policy Act of 1978 was the first substantial piece of gas legislation enacted since the Natural Gas Act of 1938.[1/] A year before the NGPA was signed into law, the Congress had enacted the Emergency Natural Gas Act (ENGA) which authorized emergency allocations and supplemented FPC rules governing emergency sales. The curtailment policies of the NGPA, however, superceded the ENGA.

3.1 Politics of the NGPA

The NGPA originated with the National Energy Plan that the Administration sent Congress in April 1977. The House adopted the Administration's plan, with minimal revision, as part 4 of the National Energy Act, H.R. 8444, in August 1977. The Senate passed a substantially different version of the Administration's proposal in S. 2104, the Natural Gas Policy Act, in October 1977. The Conference Committe bill was reported in the next session of Congress, survived a vote to recommit in the Senate, and was adopted at the end of September 1978.

The Administration's natural gas plan revised producer price ceilings in the interstate market and extended Federal producer price controls to the intrastate market for the first time in the history of U.S. gas regulation. As shown in Table 3.1, the House version of the National Energy Act established a ceiling price for new natural gas at $1.75/MMBtu plus escalation based on the price of domestic crude oil. The House bill provided an incremental pricing mechanism applicable to low priority customers in both

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1/ In 1955, one year after the Phillips Case, the Congress passed the Harris-Fulbright deregulation bill, which would have exempted producers from FPC rate regulation. Eisenhower vetoed the bill alleging excessive industry pressure had been exerted on some Congressmen. The Senate had twice voted deregulation from 1973 to 1977, but the House failed to concur.

PROVISION	HOUSE	SENATE	CONFERENCE
WELLHEAD PRIC			
• NEW GAS		1. Sold and delivered for first time after 1/1/77 excluding withheld gas.	
onshore	1. Drilled after 4/20/77 2. 1000' deeper than wells within 2.5 miles	2. Reserve discovered after 1/1/77 including deeper drilling of existing well	1. House version excluding withheld gas 2. Drill d after 2/19/77 ("new onshore production well")
offshore	1. Lease granted after 4/20 4/20/77	3. Extension of existing reservoir drilled after 1/1/77	1. House Version 2. Reservoir discovered after 7/27/76 on old lease
• BASE PRICE	$1.75/MMBtu		$1.75/MMBtu
onshore		1. BTU equivalent of No. 2 ($2.48/MMBtu)	
offshore		1. Interim Price at new domestic crude ($1.90/MMBtu) 2. FERC National Ceiling Price	
• ESCALATOR	Average refiner acquisition cost of domestic crude oil	No. 2 Fuel Oil landed in NYC	Monthly inflation factor of $(\frac{GNP}{100} + 1.002 + GF)^{1/12}$ Where: GNP = quarterly change of the implicit price deflator expressed as annual rate. 1. New Gas: GF = .035 before 4/20/81, .040 thereafter 2. New onshore production well: GF = 0.
• INTRASTATE GAS	Included under price regsulations	Excluded	Included under price regulations
• DEREGULATION	None	1. Onshore in 1981 2. Offshore in 1984	1. New Gas in 1985 2. New Onshore Production well in 7/1987. 3. Standby Price Control Authority

PROVISION	HOUSE	SENATE	CONFERENCE
Incremental Pricing • Low Priority Customers	Industrial and Commercial using more than 50 Mct/ peak day	Same as House Version, excluding Hospitals, agriculture, and food processors.	1. Industrial boiler customers using more than 300 Mct/peak d in 1977 excluding hospitals, agricultural users, electric utilities, and cogenerators 2. Other users added by FERC recommendation, not vetoed by either House, after 5/80.
• Local Distributors	Included low priority customers of distribution utilities	Excluded low priority customers of distribution utilities	House Version
• Intrastate Market	Included intrastate customers	Excluded Intrastate Customers	Senate Version
Curtailment Policies • High Priority Customers	1. Residential 2. Commercial less than 50 Mct/peak day 3. Essential Agriculture 4. Essential for health and Safety	1. House Version 2. Essential Industrial process and feedstock users	1. Senate Version 2. Secretary of DOE sets curtailmen priorities, FERC implements, following DOE Reorganization Ac
• Intrastate Market	Included	Excluded	Excluded

HOUSE, SENATE AND CONFERENCE COMMITTEE VERSIONS OF THE NGPA in both the inter- and intra-state markets. It would have passed through natural gas price increases to industrial and larger commercial customers up to the cost of alternate fuel at the burner tip. Curtailment priorities were revised and extended into the intrastate market.

In the Senate, where the influence of populous consumer states is weaker than the House, the debate over natural gas policy was long and intense. Senators Metzenbaum (D-Ohio) and Abourezk (D-South Dakota) conducted a week-long fillibuster to forestall the majority favoring deregulation. Senators Bentsen (D-Texas) and Pearson (R-Kansas), representing producer states, proposed a substitute bill which: (1) deregulated new onshore and offshore gas in 2 and 5 years, respectively; and (2) established an initial price ceiling of $2.48 with escalation tied to the price of No. 2 distillate fuel oil. Senator Jackson proposed a compromise bill to end the fillibuster, but lacked sufficient support. The President exhorted the Senate to pass his energy plan with little effect: the Senate conducted its first all-night session in 13 years, and members wearied as over 500 amendments were offered.[1/] Hoping to win in the Conference Committee, or perhaps to get an energy bill at any cost, the President sent Vice-President Mondale to end the fillibuster.[2/] After two weeks of debate, the Senate passed S.2104 which followed the Bentsen-Pearson deregulation bill, and included a weak version of incremental pricing pertaining only to low priority customers purchasing gas directly from interstate pipelines.

1/ Edward Falck. "The Natural Gas Policy Act: A Strange History." Public Utilities Fortnightly, (October 12, 1978).

2/ Mondale ended the fillibuster, with the help of Senate Majority leader Byrd, by making a series of questionable and bitterly contested rulings on the Senate floor.

This limitation of incremental pricing was significant because direct sales (1.2 Tcf) comprise only 20 percent of the volume sold to low priority interstate customers.

The Conference Committe faced the difficult task of reconciling the very different versions of the NGPA passed by the House and Senate. The Conference bill took on the appearance of a patchwork quilt: the Conference Committee adopted the House proposed extension of price controls to the intrastate market, but not the intrastate curtailment policies. The Conference bill thus threatens shortages in the intrastate market, but provides no mechanism to cope with curtailments. The most bizarre feature of the compromise bill is the escalator formula, based on the twelfth root of a modified version of the quarterly implicit price deflator. The Conference Committee escalator is unrelated to either Congressional bill, both of which tied ceiling prices to the cost of oil products.

The conference agreement expanded the definition of new natural gas in favor of the Senate, but prolonged the period prior to deregulation in favor of the House. The initial new gas ceiling price adopted followed the House, while the price escalator differs from both Congressional bills. The incremental pricing provisions narrowed the class of low priority customers affected, but followed the House method of passing through increased gas costs to low priority customers.

The bill was opposed by members of groups representing every interest: the Independent Producers Association and many oil companies were opposed, most pipelines and distribution companies were against incremental pricing, and Senators Metzenbaum and Abourezk were joined by pro-producer Senators like Hansen (R-Wyoming) and Long (D-Louisiana) in voting against the bill.

3.2 Provisions of the NGPA

The NGPA is divided into six titles: (1) Wellhead Pricing, (2) Incremental Pricing, (3) Additional Authorities and Requirements, (4) Natural Gas Curtailment Policies, (5) Administration and Enforcement, and (6) Coordination with the Natural Gas Act; Effect on State Laws. The provisions of particular interest are explained below, and the consequences of the NGPA are analyzed in Section 4.

3.2.1 Wellhead Pricing

The NGPA creates eight major categories, and 30 or more subcategories, of gas for pricing purposes (see Table 3.1). Initial prices are set for gas in each category subject to an escalation factor given by:[1/]

$$P_n = P_{n-1} \, (GNP/100 + 1.002 + GF)^{1/12}$$

where: P_n = price applicable for month n

GNP = the quarterly percent change of the GNP implicit price deflator, expressed as an annual rate, for the last quarter

GF = growth factor

The price ceiling increases at the rate of inflation; given by the GNP implicit price inflator, plus a correction factor of 1.002 representing the average difference between the consumer price index and GNP implicit index, plus a real growth factor. The growth factor for new gas, rollover contracts, stripper well gas, and intrastate gas is 3.5 percent through April 1981, and 4 percent thereafter. The growth factor for new

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1/ Natural Gas Policy Act.

NATURAL GAS CATEGORIES APPLICABLE UNDER NATURAL GAS POLICY ACT OF 1978[1]

NATURAL GAS CATEGORIES	April 1977	May 1978	DATE OF ENACTMENT (NOVEMBER 9, 1978)	1979	1980	April 20, 1981	1981	1982	1983	1984	1985	JULY 1, 1987
	IMPLEMENTATION DATES AND PROJECTED PRICES[2]											
NEW NATURAL GAS (SEC. 102)												
• OUTER CONTINENTAL SHELF NEW LEASE PRODUCTION • OUTER CONTINENTAL SHELF NEW RESERVOIR DISCOVERED ON OLD LEASE (ON OR AFTER 7.27.76) • NEW ONSHORE WELL > 2.5 MILES FROM NEAREST MARKER WELL[4] • NEW ONSHORE COMPLETION > 1000 FEET BELOW DEEPEST COMPLETION OF ANY MARKER WELL[4] WITHIN 2.5 MILES • NEW ONSHORE RESERVOIR (NO PRODUCTION IN COMMERCIAL QUANTITIES BEFORE 4.21.77)	$1.75 (I + .035)			2.000	2.200	(I + .04)	2.500	2.740	3.000	3.290	DEREGULATED	
NEW ONSHORE PRODUCTION WELLS (SEC. 103)												
• PRODUCTION IN NEW WELL FROM COMPLETION < 5000 FEET DEEP NOT DEDICATED TO INTERSTATE COMMERCE ON 4.20.77	$1.75 (I)			1.900	2.001		2.300	2.226	2.400	2.900	MIDWAY BETWEEN NEW GAS PRICE AND $1.75 (I)	DEREGULATED
• PRODUCTION IN NEW WELL FROM COMPLETION > 5000 FEET DEEP NOT DEDICATED TO INTERSTATE COMMERCE ON 4.20.77	$1.75 (I)			1.900	2.001		2.200	2.376	2.4[illegible]	2.9[illegible]	DEREGULATED	
NATURAL GAS DEDICATED TO INTERSTATE COMMERCE (SEC. 104)												
• PRODUCTION FROM WELLS COMMENCED ON OR AFTER 1/1/75 AND BEFORE 2.19.77	$1.45 (I)			1.630	1.732		1.831	1.936	2.046	2.162	2.289	
• PRODUCTION FROM WELLS COMMENCED ON OR AFTER 1/1/73 BUT BEFORE 1.1.75	$.93 (I)			1.064	1.125		1.190	1.257	1.329	1.406	1.486	
• PRODUCTION FROM WELLS COMMENCED BEFORE 1/1/73	$.295 (I)			.334	.353		.373	.394	.416	.440	.465	
• REPLACEMENT CONTRACT GAS	$.53 (I)			.598	.630		.668	.704	.744	.788	.831	
• PRODUCTION UNDER SPECIAL FERC PRICES ESTABLISHED AFTER 4.20.77 BUT BEFORE ENACTMENT	$1.45 (I) OR SPECIAL FERC PRICE			1.630	1.732		1.831	1.935	2.046	2.162	2.285	
NATURAL GAS UNDER EXISTING INTRASTATE CONTRACTS[3] (SEC. 105)												
• EXISTING CONTRACT WHERE PRICE IS < THAN NEW GAS PRICE			LOWER OF EXISTING CONTRACT PRICE OR NEW GAS PRICE									
• EXISTING CONTRACT WHERE PRICE IS > THAN NEW GAS PRICE			HIGHER OF EXISTING CONTRACT PRICE OR NEW GAS PRICE									
• EXISTING CONTRACT WHERE PRICE IS > $1.00 MMBtu AS OF 12/31/84 AND NOT AS A RESULT OF ANY INDEFINITE PRICE ESCALATOR CLAUSE											DEREGULATED	
• EXISTING CONTRACT WHERE PRICE IS < $1.00 MMBtu AS OF 12/31/84 AS A RESULT OF ANY INDEFINITE PRICE ESCALATOR CLAUSE											HIGHER OF CONTRACT PRICE AT DATE OF ENACTMENT (I) OR NEW GAS PRICE (I + .05)	
ROLLOVER CONTRACTS (SEC. 106)												
• INTERSTATE ROLLOVER CONTRACT	HIGHER OF FERC PRICE (I) OR $.54 (I)			.607	.642		.679	.718	.760	.803	.849	
• INTRASTATE ROLLOVER CONTRACT	HIGHER OF PREVIOUS CONTRACT PRICE (I) OR $1.00 (I)			1.120	1.190		1.260	1.330	1.400	1.480	DEREGULATED IF CONTRACT PRICE IS > $1.00	
• STATE GOVERNMENT PRODUCTION (INCLUDES PRODUCTION ON OWNED LAND, ROYALTIES AND OTHER INTERESTS) • INDIAN TRIBAL PRODUCTION (INCLUDES PRODUCTION OF LAND IN TRUST FOR INDIANS)	$1.75 (I + .035)			2.000	2.200	(I + .04)	2.500	2.740	3.000	3.290	DEREGULATED	
HIGH COST GAS (SEC. 107)												
• PRODUCTION FROM COMPLETION LOCATION > 15,000 FEET DEEP IN WELL COMMENCED ON OR AFTER 2.19.77	NEW GAS PRICE OR SPECIAL FERC PRICE			DEREGULATED AS OF FIRST INCREMENTAL PRICING RULE								
• GEOPRESSURED BRINE GAS • COAL SEAM GAS • DEVONIAN SHALE GAS			OTHERWISE APPLICABLE PRICE OR SPECIAL FERC PRICE									
• OTHER GAS DETERMINED BY FERC TO BE HIGH COST			OTHERWISE APPLICABLE PRICE OR SPECIAL FERC PRICE									
STRIPPER WELL GAS (NON-ASSOCIATED) (SEC. 108)												
• STRIPPER PRODUCTION AVERAGING < 60 Mcf/d OVER A 90 DAY PERIOD AT ITS MAXIMUM EFFICIENCY RATE • STRIPPER PRODUCTION INCREASED TO AN AVERAGE > 60 Mcf/d OVER A 90 DAY PERIOD DUE TO ENHANCED RECOVERY TECHNIQUES		$2.09 (I + .035)		2.343	2.440	(I + .04)	2.676	2.888	3.212	3.534	3.888	
NATURAL GAS NOT COVERED BY ANY OTHER PRICE PROVISION (SEC. 109)												
• NATURAL GAS DEDICATED TO INTERSTATE ON DAY BEFORE ENACTMENT WITH NO FERC PRICE IN EFFECT • NATURAL GAS NOT DEDICATED TO INTERSTATE AND NOT SUBJECT TO AN EXISTING CONTRACT ON DAY BEFORE ENACTMENT • PRUDHOE BAY UNIT GAS • PRODUCTION FROM ANY WELL NOT OTHERWISE QUALIFYING FOR HIGHER PRICE	$1.45 (I) OR SPECIAL FERC PRICE			1.630	1.732		1.831	1.936	2.046	2.162	2.286	

[1] [illegible]

[2] [illegible]

[3] [illegible]

[4] [illegible]

Source: AGA American Gas Association

January 1, 1979

TABLE 3.1

onshore production wells and old interstate gas is zero. The Conference bill escalator is substantially more complicated than either House or Senate versions, and has less, if any, economic rationale.

The Conference bill included a standby price control authority which authorizes the President or the Congress to reimpose price controls for a single period of 18 months at the expiration of new gas price ceilings in 1985. The econometric analysis in Section 4 indicates that deregulation in 1985 would result in a 30% jump in the average price of natural gas in the interstate market. Standby price control authority will likely be involved, extending controls up to 1987. Producer price controls may become a rather permanent fixture in the intrastate market where federal regulation did not previously extend.

3.2.2 Incremental Pricing

The incremental pricing provision is the most confusing section of the Conference bill. The Conference Committe writes in the Conference report, " ... we recognize that implementation of this program will be complex." The Committee left implementation to FERC rule, providing a vague description of the mechanics in the bill. There are four basic components to the incremental pricing program: (1) calculation of the increased costs of natural gas to be included in the incremental pricing account (IPA); (2) identification of low priority customers in the incremental pricing pool and measurement of the volume of gas delivered to these customers; (3) determination of the alternate fuel cost, at the burner tip, of incrementally priced customers, and; (4) allocation of costs in the IPA (i.e., surcharges), based on volumes consumed by low priority customers, such that no customer is surcharged above the alternate fuel price.

The Act is most explicit concerning the calculation of the IPA and the measurement of low priority consumption. The IPA is equal to the amount spent by interstate pipelines for gas in excess of the base price ($1.48/MMBtu plus escalation without a growth factor). Low priority customers in the incremental pricing pool are industrial boiler users having had an average daily use of more than 300 Mcf during calendar year 1977; except that a lower standard must be set by FERC in order to include at least 95 percent of the gas, used for boiler fuel, transported by interstate pipelines in 1977. The alternate fuel price is the regional (as designated by FERC) price of No. 2 distillate fuel oil, unless a lower price, not lower than No. 6 residual fuel oil, is deemed by FERC to yield larger surcharge collection.

The Act expressly prohibits distributors from lowering rates to industrial customers to offset surcharge payments. The Act is silent on whether distributors may raise industrial rates to the alternate fuel price, lowering residential/commercial rates, and shifting surcharge collection onto other distributors.

The genius of incremental pricing was that, in principle, it allowed the well-head price of gas to rise with minimal impact on consumer rates by taxing large industrial customers. With the enactment of the well-head and incremental pricing provisions, the last free limbs of the gas market--intrastate field prices and distributor rates--were caught in the tar of federal regulation.

3.2.3 Curtailment Policies

The Conference bill requires the Secretary of Energy to amend the current schedule of curtailment priorities to include essential agriculture, process, and feedstock users as high priority (c.f., Table 2.7) customers. The Committee was well aware of the protracted legal battles involved in the establishment of pipeline curtailment plans based on the 1973 curtailment priorities:

> The Conferees were concerned that these changes not burden the Commission with lengthy proceedings which might throw existing curtailment plans into disarray.1/

The Act does increse the likelihood that existing curtailment plans will become unworkable. But of greater concern, over the 1978-87 period, is the continuance of the 1973 system of allocating gas by enduser category rather than use value. In Section 4, this inefficient allocation is estimated to cost the economy one billion dollars annually.

3.3 Summary

The NGPA of 1978, hailed as a deregulation bill, is in the short term (from 1978 to 1985 or 1987), quite the contrary. The curtailments induced by federal regulation of well-head rates in the interstate market are symptomatically treated by new regulations governing field prices in the state markets and distributor rates for large industrial customers. The wellhead and incremental pricing provisions of the NGPA were elaborate compromises which buffered interstate consumers from curtailments and price in-

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1/ Conference Report. Joint Statement of the Committee on Conference. p. 113.

creases (by transferring rents from intrastate producers and industrial customers) while allowing well-head prices to rise with the GNP deflator, but not to market clearing levels.

Will the Act improve the performance of the gas market or will the "regulatory-fix" create new and unforseen distortions? The analysis in Section 4 suggests that the Act benefits residential and commercial customers at the expense of intrastate producers and industrial customers. There is little evidence that the Act improved the efficiency of the market. In any case, the implementation costs will not be trivial. The Chairman of FERC estimates an additional 300 employees will be required which would easily cost FERC $60 million over the decontrol period (1978-1987).[1/]

1/ Assuming 300 employees at an average $15,000/yr, with overhead equal to direct labor costs, for a period of 8 years discounted at a real rate of 4 percent/year. Private compliance costs are neglected.

Section 4. Economic Consequences of the NGPA.

In the short run, 1978 to 1987, the economic implications of the NGPA may be perverse. The Act, among other things, (1) extends federal pric^ controls into the intrastate market for the first time, (2) maintains inefficient curtailment policies, (3) creates incentives for distributors to restate boiler customer rates under incremental pricing, and (4) generates non-trivial compliance costs for industry and government. The regulation of deregulation in the natural gas industry is seen to promote, rather than eliminate, inefficiency and bureaucratic burden. The economic effects of wellhead and incremental pricing and curtailment policies are examined in this section.

4.1 Wellhead Pricing

The analysis of the wellhead pricing provisions addresses three questions:

(1) How do NGPA price ceilings for new natural gas compare to the unregulated price of gas? Will there be a sizable gap in 1985 when price controls are to be lifted?

(2) Are curtailments likely to persist under the NGPA?

(3) Did the NGPA raise the price of gas in the interstate market relative to the pre-existing nationwide ratemaking policy of the Federal Energy Regulatory Commission?

Unregulated Price of Gas. The Natural Gas Policy Act as finally drafted by the Conference Committe linked the upper tier price of natural gas to the rate of inflation as measured by the consumer price index. The base price o˜ gas was established as $1.75/Mcf in April 1977 with an allowed real rate of escalation of 3.5 to 4.0 percent from 1977 to 1985. In the fourth quarter of 1978 when the Conference Bill was enacted, the ceiling price of new gas, under the escalator, deviated from the world price of gas by just 6% (see Table 4.1).

YEAR	QUARTER	PRICE OF GAS IMPORTS $	NGPA CEILING PRICE FOR NEW GAS $	IMPORT PRICE / CEILING PRICE
1977	I	2.01		
	II	1.90	1.75	
	III	1.89	1.75	
	IV	2.14	1.75	
1978	I	2.12	1.75	
	II	2.20	1.75	
	III	2.21	1.75	
	IV	2.20	2.07	1.06
1979	I	2.17	2.13	1.02
	II	2.28	2.18	1.05
	III	2.57	2.24	1.15
	IV	3.26	2.31	1.41
1980	January	3.46	2.36	1.47
1985	January	3.46[a/] - Low	2.85[a/]	1.21
		3.81[a/] - Middle		1.34
		4.99[a/] - High		1.75

Source: EIA. Monthly Energy Review (May, 1980) FERC.

Table 4.1 NGPA Ceiling and World Price of Gas

The Iranian revolution followed shortly after the NGPA was signed into law, sending the world price of fossil fuels sharply upward. Between 1978-IV and 1979-IV the price of gas imports increase 48% while the ceiling price rose by 11.6% (inflation as measured by the CPI plus .035). In one year after the passage of the NGPA, the relative parity between the new gas ceiling and

a/ In January 1980 dollars.

the world price was knocked out of alignement.

Table 4.1 shows the path of world gas prices under three scenarios:

1. Low Case - zero real increase 1980-1985
2. Middle Case - 3.8% real annual increase 1980-1985
3. High Case - 7.6% real annual increase 1980-1985

The low case is the 1980 price level; the middle case assumes a real increase in the world gas price at the rate implicitly anticipated by the Conference Committee (3.5% through April, 1981 and 4% thereafter through 1985, averaging 3.8% over the 1980-1985 period); and the high case assumes real price escalation at twice the middle level. The gap in 1985 between the world and ceiling prices is 21% in the low case, 34% in the middle case, and 75% in the high case (c.f. Table 4.1).

The evidence strongly suggests a substantial difference between the unregulated gas price and the NGPA ceiling price in 1985. The magnitude of this gap casts doubt upon the lifting of price controls in 1985.[1/] The temptation for the President or the Congress to invoke standby price controls in 1985 may be irresistable. Standby price controls extend the price ceilings for a period of 18 months after the expiration of the Act. The possibility that controls will be renewed indefinitely cannot be completely discounted given the propensity for "politically smoothing" energy prices--the reluctance to allow abrupt increases in consumer fuel bills.

1/ The likelihood that the NGPA will be amended to allow for the unanticipated rise in the world gas price is vanishingly small. Having ventured into the hornet's nest of gas deregulation politics once, the Congress is reluctant to tamper with the Conference Bill Compromise.

Market Clearing Price of Gas. The effect of the NGPA on curtailments depends not only on wellhead price controls, but on the incremental prices charged to non-exempt (large industrial boiler) customers. The NGPA affects the price of gas both in the field and at the other end of the pipeline. To accurately forecast curtailments both boiler and non-boiler customer demand on each pipeline must be known. We follow the simpler approach of estimating curtailments in the absence of incremental pricing, assuming the structure of relative customer rates remains constant. This gives an upper bound estimate of the market clearing field price and the associated curtailments.[1/]

To estimate the upper bound level of curtailments a simple econometric model of the interstate gas market from 1957-1978 was constructed. The excess demand function, based on FERC curtailment data, was estimated (see Appendix I for details). The market-clearing price was determined by solving for the price level which set excess demand equal to zero. The market-clearing price was forecast under three world oil price scenarios characterizing low, middle, and high levels of real fuel price escalation (described in the previous section).

The estimated market clearing prices under each scenario are shown in Table 4.2. The NGPA ceiling price for new gas is shown to be higher than the estimated market clearing price in all scenarios. However, the NGPA average price of gas in the interstate market depends on how fast new gas reserves are brought into production. This may be described by the reserve to production ratio for higher price gas: a high reserve/production ratio implies that the proportion of new gas production in total deliveries rises slowly and conversely. Using a high and low case for the reserve to production

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1/ Assuming industrial demand is more elastic than residential. If the reverse were true, incremental pricing would increase the probability of curtailments.

PRICE	WORLD OIL PRICE SCENARIO[a/]	RESERVE-TO-PRODUCTION RATIO[b/]	(1967 DOLLARS) 1980	1981	1982	1983	1984	1985	ESTIMATED ANNUAL CURTAILMENT 1985
MARKET-CLEARING	LOW	--	.69	.71	.74	.77	.81	.84	
NGPA AVERAGE	LOW	HIGH	.55	.58	.61	.64	.67	.70	5.3%
NGPA AVERAGE	LOW	LOW	.55	.61	.67	.72	.77	.82	0.7%
MARKET-CLEARING	MIDDLE	--	.69	.72	.76	.80	.85	.89	
NGPA AVERAGE	MIDDLE	HIGH	.55	.59	.63	.67	.70	.74	5.7%
NGPA AVERAGE	MIDDLE	LOW	.55	.62	.68	.74	.80	.85	1.5%
MARKET-CLEARING	HIGH	--	.69	.73	.78	.83	.89	.95	
NGPA AVERAGE	HIGH	HIGH	.55	.60	.65	.69	.73	.78	6.1%
NGPA AVERAGE	HIGH	LOW	.55	.63	.70	.76	.82	.88	2.4%
NGPA NEW GAS	ALL	--	.93	.96	1.00	1.04	1.08	1.12	

Table 4.2 Market-Clearing Price Under NGPA (Upper Bound)

a/ LOW = 0% real escalation; MIDDLE = 3.8% real escalation; HIGH = 7.6% escalation.

b/ Reserve to production ratio: LOW = 7.1%; HIGH = 12.5%.

ratio, the average price of interstate gas under each world oil price scenario was estimated.[1/] Table 4.2 shows that under all scenarios, the annual curtailment in the interstate market is greatly reduced from the 24% level that prevailed in 1978/79. These curtailment figures indicate that gas shortages in 1985 are likely to affect only interruptible customers.

Although the ceiling price of interstate gas is estimated to fall considerably short of the unregulated gas price in 1985, shortages are likely to be reduced in the interim period. The NGPA is seen to hold down the price of gas to small consumers and protects them from curtailments by taxing, in effect, intrastate producers and industrial customers.

FERC Nationwide Ratemaking Policy.

The NGPA price ceiling superceded price controls set by the FERC under its nationwide ratemaking policy. Hailed as a deregulation measure, the NGPA decontrols natural gas field prices in seven to eight years, reversing the 24-year policy of Commission control over wellhead rates. But did the NGPA actually raise the price of gas relative to the pre-existing nationwide ratemaking formula?

Figure 2.2 clearly shows that during the period of Nationwide Ratemaking (1974-1978), the Commission set the ceiling price for new natural gas in line with the world price each biennium (two years). Therefore the ceiling price tracked the world market price with a two-year regulatory lag. The NGPA ceiling price rises with the GNP deflator rather than the world price of

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1/ The price of oil affects exploration incentives which in turn affects associated gas reserve discovery.

fuels. Since the world price of gas has increased at rates vastly exceeding inflation after the enactment of the NGPA (about 55% per annum), it is quite plausible that, in the absence of the NGPA, the FERC's nationwide ratemaking policy would have resulted in new gas prices much closer to the unregulated level. The NGPA may well have increased the gap between the controlled and unregulated gas price at least in the 1978-1985 time frame.

4.2 Incremental Pricing

The incremental pricing provisions of the NGPA were designed to mitigate the effects of increased gas acquisition costs on residential and small commercial customers, in the interstate market, at the expense of large industrial boiler users. The Act is unusually explicit in the statement of this objective in the guidelines for determining the "alternative fuel cost" of industrial boiler facilities. The alternative fuel cost sets a cap on the amount of surcharge which can be collected from any incrementally priced customer:

> . . . the appropriate alternative fuel cost for any region . . . shall be the price, per million Btu's, for Number 2 fuel oil . . . The Commission may . . . reduce the appropriate alternative fuel cost . . . to an amount not lower that (sic) the price, per million Btu's, for Number 6 fuel oil . . . if such reductions are necessary to prevent increases in the rates and charges to residential, small commercial, and other high priority users of natural gas which could result from a reallocation of costs caused by the conversion . . . from natural gas to other fuels . . . if the level of the appropriate alternate fuel cost were not so reduced.[1/]

The NGPA instructs the Commission to act as revenue maximizing monopolist, picking the price which extracts the largest contribution from boiler

1/ U.S. House of Representatives. "Natural Gas Conference Report." Report No. 95-1752, 204(3), p. 30.

customers. The alternative fuel cost specified by the Act is illustrated in Figure 4.1 as price OA which maximizes the area of the contribution rectangle (ABGF). The price which maximizes contribution depends on the elasticity of low priority demand in the relevant range (between the price of resid and distillate fuel oil). If demand is highly elastic then the contribution maximizing alternative fuel cost is closer to the price of resid than distillate, and conversely. In the short run, supply available to low priority customers depends on the gas available to pipelines and the level of (temperature sensitive) high priority residential and commercial demand. Given that high priority deliveries are politically protected, the efficient low priority price is CD, the price which just clears the market. It can be shown that the contribution maximizing price (AO) is greater than or equal to the efficient price (CD), but there is no necessary equality. Incremental pricing will result in the efficient pricing of low priority customers only by luck.

Inefficient pricing might be justified by equity considerations if residential and commercial customers are more "deserving" of cheap gas than industrial boiler users, and if the Act really lowers the price of gas to the high priority group.[1/] But do contribution maximizing incremental pricing surcharges benefit the population of high priority customers? The higher cost of gas to industrial customers is passed on to the consumers of industrial products and to the stockholders in firms

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1/ Of course, distributional objectives are better achieved through taxes which do not distort product prices, but suppose it is assumed that alternative tax instruments are unavailable.

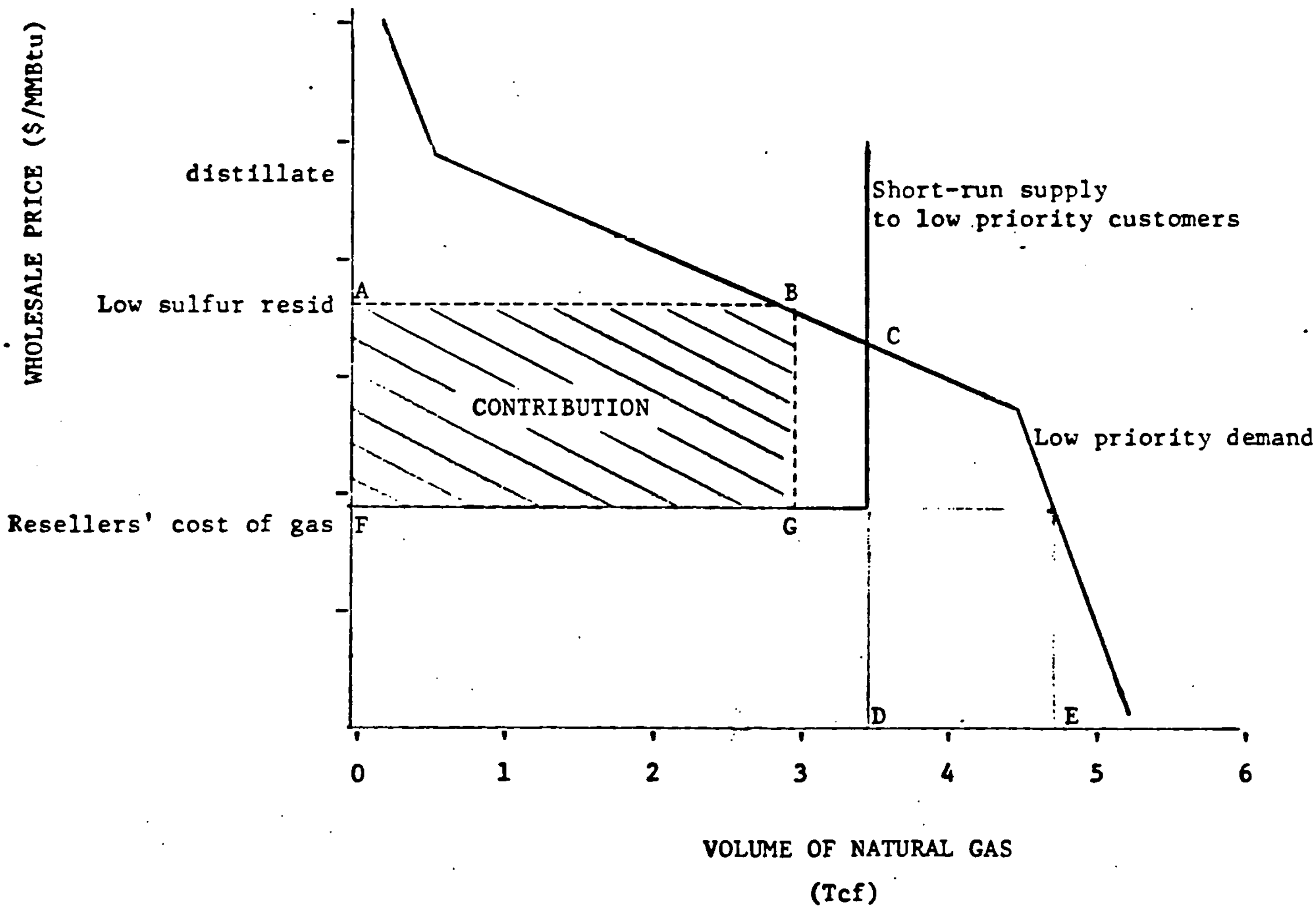

Figure 4.1 ALTERNATIVE FUEL COST UNDER INCREMENTAL PRICING

1/ 1978-79 demand data and August 1979 prices. The shape of the demand curve is assumed for illustrative purposes.

using natural gas. What residential customers gain in lower gas prices is taken away, in part, by higher product prices and reduced dividends in industries with boiler gas use. Obviously, the pattern of net benefits among consumers is complex an. depends on geographic location, consumption patterns and stockownership; but the conclusion is straightforward: all consumers are unlikely to benefit from incremental pricing.

In addition to these questions of efficiency in pricing and surcharge incidence, we argue that incremental pricing creates incentives for distributors to restate industrial rates and shift surcharges, which benefits high priority customers of distribution utilities near the well-head at the expense of those at the end of the pipeline. The aggregate effect of distributor surcharge shifting activities is shown in Figure 4.2. If distributors react passively to incremental pricing then pipeline surcharge collection increases monotonically with the surcharge rate; up to the maximum surcharge absorption capability (MSAC), as illustrated by the gross surcharge function. Alternatively, distributors may recognize that raising industrial rates to the alternative fuel price allows them to capture surcharge payments, and has no affect on the fuel bills of boiler customers surcharged up to the cap. Instead of paying surcharges to the pipeline, the distribution company raises industrial and lowers consumer rates, eliminating its surcharge absorption capability. The incremented pricing account is then spread over boiler customers in other distribution service areas. If distributors react rationally, net surcharge collections are always less than the gross surcharge function in Figure 4.2, and the maximum net sur-

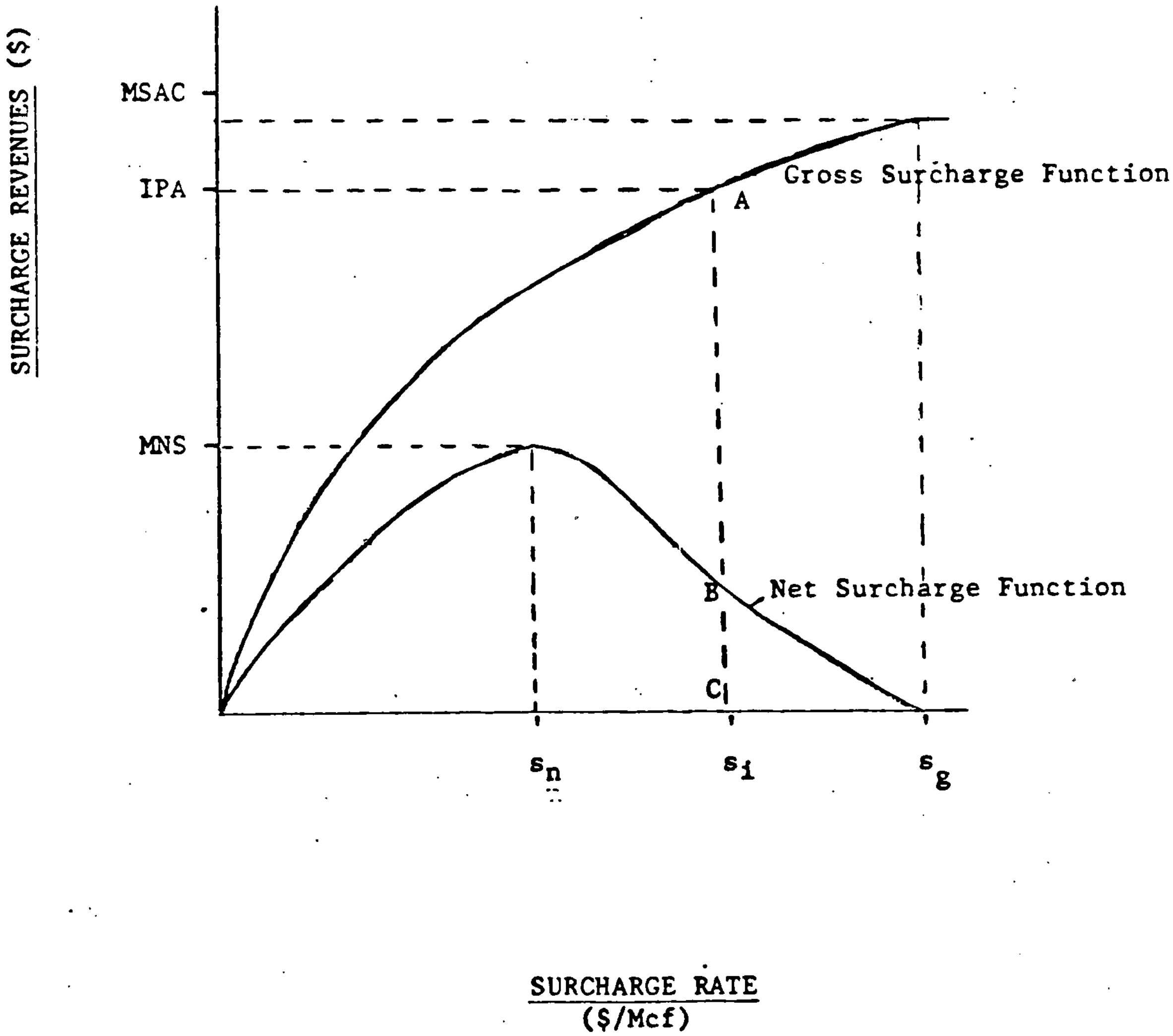

Figure 4.2 INCREMENTAL PRICING SURCHARGE REVENUES

charge (MNS) occurs at a lower surcharge rate (S_n) than would be predicted assuming passive distributor behavior (S_g).

This static view of the net surcharge function as non-monotonic implies that the surcharge rate necessary to absorb the incremental pricing account need not be unique. Furthermore, increasing the surcharge rate may raise or lower net surcharge revenues depending on whether the pipeline rate is to the right or left of S_n. From a dynamic point of view, it is unlikely that pipelines could successfully increase surcharge collections by lowering the surcharge rate. A "ratchet effect" results from the reluctance of distributors to lower industrial and raise consumer rates in response to a decrease in the pipeline surcharge rate. This model of rational distributor behavior implies that once the incremental pricing account (IPA) exceeds the maximum net surcharge (MNS), an inevitable spiral of increased revenue shortfall followed by increased surcharge rate is initiated, until surcharge collections fall to zero. In equilibrium no surcharge revenues are collected, and industrial customers are priced at the alternative fuel cost.

If incremental pricing operates according to the "rational distributor" model depicted, then ultimately surcharge shifting would appear to be ineffective: all boiler customers are priced incrementally and the rates of residential and commercial customers are correspondingly lower. This need not, however, be the case if the boiler customers of some distributors are initially priced above the alternative fuel price set by the Commission. This is illustrated in Table 4.3 where, for the purpose of example, we have taken the New England and South Atlantic regions to be two distribution companies along an eastern seaboard pipeline (e.g., Transcontinental Gas Pipe Line Corporation). Initially we assume the incremental pricing account is $250 million which is exactly absorbed by a surcharge of $0.55/Mcf on gas sold to non-exempt boiler customers in the South Atlantic. The industrial rate in the South Atlantic is assumed to be $1.60/Mcf, which is surcharged up to the alternative fuel price ($2.15).1/ The South Atlantic responds rationally by raising its industrial rate to the alternative fuel price and lowering its charges to exempt customers by the surcharge (250 million).2/ Since the incremental price account cannot be absorbed (MSAC=0), the $250 million is transferred to the pipeline general account where it is allocated to distribution companies on the basis of volume sales. The New England distribution company accounts for a little more than 20 percent of pipeline volume sales so $51 million of the $250 million in the pipeline general account is charged to New England. The end result (panel three, Table 4.3) is that New England residential and commercial customers pay more ($4.20 vs. $4.00/Mcf) and South Atlantic residential and commercial customers pay less ($2.41 vs. $2.50/Mcf) because of the surcharge shifting incentives in the NGPA incremental pricing provisions.

The Congress intended that the incremental pricing provisions mitigate the impact of rising wellhead prices on high priority customers.

1/

The Commission has ruled that the alternative fuel price will be the regional price of resid less 2 standard deviations, thru 1981 and the regional price of distillate, less 2 standard deviations, thereafter. The example is based on 1977 data found in Gas Facts published by the American Gas Association. The national average price of low sulfur resid was $2.15/Mcf in 1977.

2/

All demands are assumed inelastic for convenience.

TABLE 4.3

CONSEQUENCES OF SURCHARGE SHIFTING

	REGION	EXEMPT CUSTOMERS			NON-EXEMPT CUSTOMERS			SURCHARGE[1]
		PRICE ($/Mcf)	VOL. (Bcf)	SALES REVENUE ($ MILLION)	PRICE ($/Mcf)	VOL. (Bcf)	SALES REVENUE ($ MILLION)	($ MILLION)
1. IMPOSITION OF INCREMENTAL PRICING	NEW ENGLAND	4.00	205	820	2.80	56	157	0
	SOUTH ATLANTIC	2.50	562	1405	1.60	453	725	250
2. RESTATEMENT OF BOILER-USER RATES	NEW ENGLAND	4.00	205	820	2.80	56	157	51[2]
	SOUTH ATLANTIC	2.06	562	1156	2.15	453	974	199[2]
3. FINAL INCIDENCE OF INCREMENTAL PRICING	NEW ENGLAND	4.20	205	861	3.00	56	168	0
	SOUTH ATLANTIC	2.41	562	1354	2.15	453	974	0

[1]Based on a low sulfur resid. cap at $2.15/Mcf in 1977.

[2]Since the South Atlantic has eliminated surcharge absorption, these figures represent the revenue requirements transferred to the pipeline general account.

The previous example shows that the effect of incremental pricing is perverse, if distributors act rationally, for residential and commercial customers of distribution companies with high cost gas (typically in the Northeast). This result hinges on the fact that low priority customers paid more for gas than the alternate fuel price in some distribution service areas in 1977. Given the 3.5-4.0 percent increase in the world oil price foreseen by the Congress, the affect of the NGPA would, indeed, have been perverse. However, the unexpected surge in world oil prices after the Iranian revolution has greatly reduced the likelihood of this adverse result. Perverse equity outcomes may still occur where state laws or distributor ignorance prevents gas rates from being restated in order to benefit exempt customers.[1/] The incremental pricing provisions have an uneven affect on equity grounds, and do not appear to increase the efficiency of natural gas pricing. The provisions do extend federal control into enduser rates which had previously been the domain of state regulatory commissions. And the administrative tasks of monitoring, accounting, and enforcement will impose a real cost on gas companies which will ultimately be borne by consumers and equity holders.

Incremental pricing does leave an important pro-efficiency contribution: that is to allocate a portion of industrial curtailment by means of <u>price</u> rather than priority classification. This will help to eliminate the economic losses resulting from FERC curtailment policies.[2/] The curtailment loss from these policies is indeed substantial, and is described in the following section. However, as we show in Section 5, a better

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1/ The loss to exempt customers is just the amount of surcharges actually paid out by non-exempt customers of the same distribution company.

2/ Assuming industrial demand is more elastic than residential.

means of eliminating curtailment loss exists that allocates gas to low priority customers efficiently.

4.3 Curtailment Policies

The NGPA incr- ises the priority of essential agricultural, process, and feedstock users of natural gas, but retains the FERC enduse priority curtailment mechanism. The FERC requires pipelines to allocate gas to distributors according to the volume of gas sold, in each priority class, in 1972. Priorities are established on the basis of enduse category from residential/small commercial down to large interruptible customers (c.f., Table 2.6). Enduser valuation of gas need not be perfectly correlated with priority class; in fact, discrepencies between enduse volume and curtailment priority are unavoidable because:

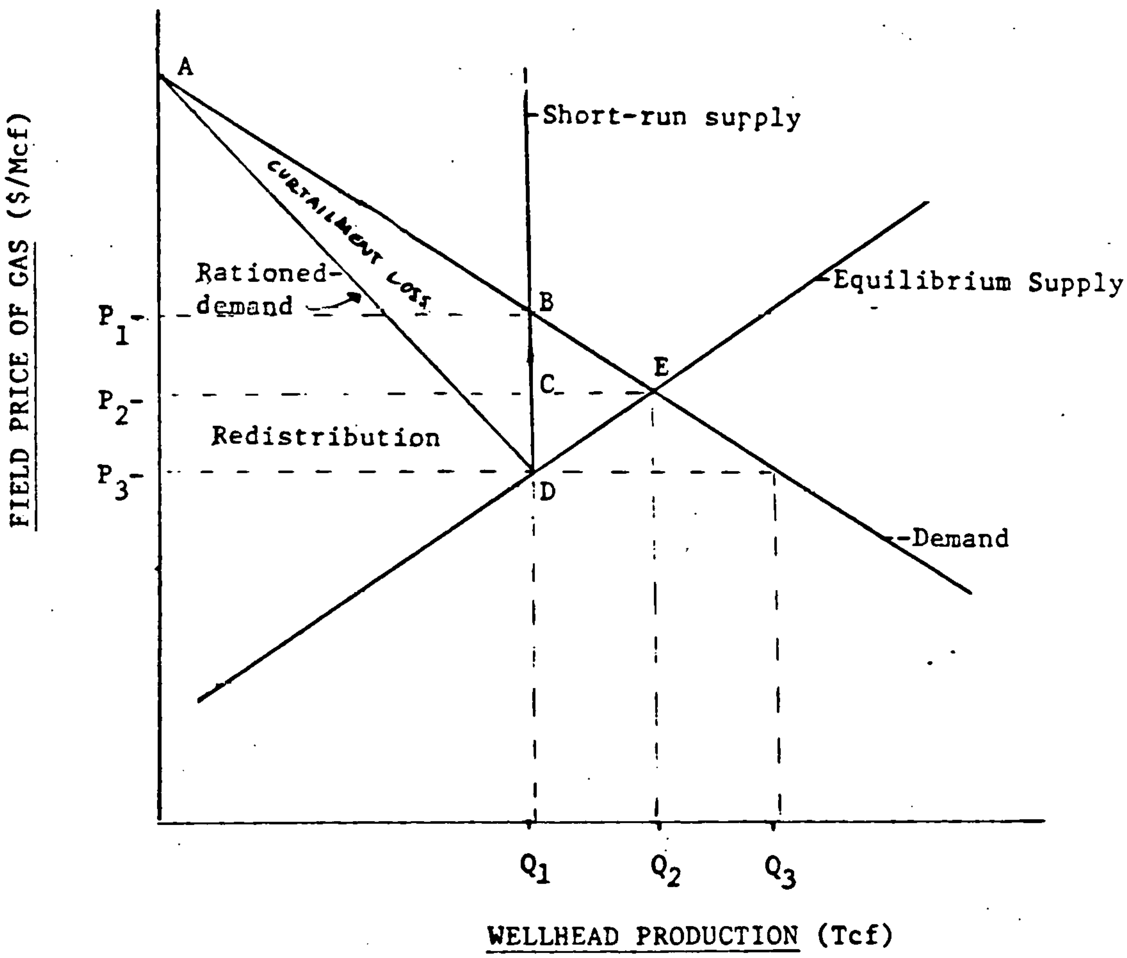
1) demand conditions have changed since the 1972 base year,
2) the FERC priorities do not recognize regional variation in the ability to burn high sulfur fuel, and
3) firm specific differences in conversion costs, for alternative fuel use, are disregarded.

The economic loss resulting from inefficient pipeline curtailment policies is represented diagramatically in Figure 4.3. If producer prices are decontrolled, and the field market is competitive, then the wellhead price of gas is determined by the intersection of demand and supply at price P_2.[1/] At a price ceiling of P_c, desired demand (Q_3) exceeds gas willingly supplied (Q_1) resulting in a shortage ($Q_3 - Q_1$). If the available supply of gas is efficiently allocated on the basis

1/ Demand is the enduser demand less the transmission cost of gas. Equilibrium supply is the quantity produced at current prices based on existing reserves, expected future prices, and anticipated discovery costs. Gas supply is linked across years: more production today means less in future years since reserves are finite.

Figure 4.3

CURTAILMENT INEFFICIENCY



of endouse value, only customers valuing gas at price P_1 (the short-run market-clearing price) and above will receive gas. Any other method of curtailment, for example pro-rata, allocates some gas to customers valuing gas below P_1 at the expense of customers with values above P_1. The "rationed" demand curve (AD) represents the value of gas to the customers who receive deliveries under the curtailment plan. Over the available supply of gas (Q_1), the area under the effective demand curve is less than or equal to the area under the demand curve. The difference is the loss in consumer value owing to inefficient curtailment (triangle ABD).1/ The "curtailment loss" may, in principle, be larger than the value of the customer savings arising from producer price controls (rectangle P_2P_3D C). In addition to curtailment loss, there is a loss from the artificial restriction of supply caused by price controls. This shifts the schedule of production out to later years reducing the discounted present value of the social benefits associated with gas consumption. The supply loss is represented by triangle BDE.

The magnitude of the curtailment loss is estimated using data on the volumes of alternative fuels used by curtailed low priority customers.2/ The curtailment loss is estimated as the price difference between the alternate fuels burned and the cost of residual fuel oil. This measures the economic gain resulting from reallocating gas delivered to interruptible customers to curtailed customers burning high cost alternate fuels (the

1/ Constant marginal utility of income and negligable income effects are assumed throughout. See Willig, R. "Consumers' Surplus Without Apology". American Economic Review.

2/ This data is collected by EIA and published annually as "Natural Gas Deliveries and Curtailments to End-Use Customers and Potential Needs for Additional Alternate Fuels."

calculations are described in detail in Appendix II). The redistribution of rents from producers to consumers resulting from price controls is estimated by the difference between the unregulated price of gas (measured by the average price of imports) and the average interstate price times the interstate volume of gas deliveries.

Table 4.4 summarizes the curtailment loss and redistribution estimates. The annual curtailment loss is estimated as ranging from $.95 to $1.35 billion in 1977, depending on the value of gas imported to curtailed customers with no alternate fuel availability. Hook moratoria, which prevented new residential gas service in most states for much of the 1970s, imposed additional curtailment losses. Existing price controls redistributed $13.8 billion from producers to pipeline companies, distributors, and interstate consumers receiving gas.

By means of incremental pricing producer price controls in the intrastate market, the NGPA will likely reduce the magnitude of curtailments over the 1978-1985 period. In the next section we argue that the Congress had options which would have eliminated much of the $1 billion a year curtailment loss, and achieved the high priority customer protection and redistribution objectives of the Act without the perverse effects of incremental pricing. In this sense, the NGPA is an inefficient piece of legislation: Opportunities remain for benefitting some groups without hurting any other interested parties.

TABLE 4.4

NATIONAL ESTIMATE OF ECONOMIC LOSS
DUE TO CURTAILMENT PLANS 1977-78[1/]
(millions of 1979 $)

ALTERNATE FUEL USED	HEATING SEASON CURTAILMENT LOSS	NON-HEATING SEASON CURTAILMENT LOSS	ANNUAL CURTAILMENT LOSS
ELECTRICITY, PROPANE AND DISTILLATE	$527	$298	$825
NO ALTERNATE FUEL AVAILABLE			
Low Case[2/]	$ 96	$ 30	$125
High Case[2/]	$400	$125	$525
TOTAL	$623-927	$328-423	$951-1350

ESTIMATED ANNUAL REDISTRIBUTION
1977-1978
(millions of 1979 $)

TOTAL	$10,910	$2,920	$13,830

1/ Curtailment losses are not net of incremental transportation costs, if any, required to reallocate gas. Excludes losses due to hook-up morotoria.

2/ Range of values for curtailed customers without alternate fuel available is $6/Mcf in the low case and $25/Mcf in the high case.

4.4 Summary

The foregoing analysis suggests surprising answers to the three questions posed on the affect of the wellhead pricing provisions on the gas market. The NGPA is seen to be a phased "recontrol" rather than "decontrol" bill. The Act increases the gap between the regulated ceiling and world price of gas. Interstate pipelines do now and will continue to pay far more for foreign sources of gas than domestic producers are permitted to charge--subsidizing imports at the expense of domestic production. Contrary to the widely held view that the NGPA is a deregulation measure, the Act extends federal control into the intrastate field market and the determination of enduser rates for the first time, while there is no evidence that the Act moves the upper tier price of gas any closer to unregulated levels than would the continuation of pre-existing FERC policies in the 1978-1985 time frame.

The Act will, according to econometric simulation, reduce the level of curtailments in the interstate market by reducing the price incentive to preferentially dedicate new gas to the intrastate markets. The incremental pricing provisions will further reduce curtailments by allocating gas on the basis of price to some low priority customers.

The question of whether controls will be lifted in 1985 is speculative, but the jump to unregulated prices is likely to be larger than politically acceptable. Decontrol may not come as quickly or as easily as expected.

The incremental pricing provisions will improve the allocation of gas to the large industrial boiler customers subject to its provisions. These provisions would promote efficiency far more effectively by including all low priority customers and charging the market-clearing rather than the revenue-maximizing price prescribed by the Act. In Section 5 a policy prescription is described which efficiently prices gas to low priority customers while avoiding the perverse incentives and distributional effects associated with incremental pricing.

Section Five. A Policy Prescription.

In the foregoing analysis we have shown that the incremental pricing provisions of the NGPA are a clumsy mechanism for reducing the economic loss associated with curtailments. In this section, wellhead rate regulation under the NGPA is taken as a constraint, and an efficient mechanism for allocating gas shortages is sought within the ambit of FERC rulemaking authority. We show that the NGPA could have achieved greater efficiency without harming residential and commercial customers.

Efficiency in curtailment requires allocation according to the enduser valuation of gas. Competitive bidding and white market mechanisms are standard candidates for efficient allocation in the absence of a market. Natural gas curtailment presents a number of special technical difficulties not found in other applications of these mechanisms. The volume of natural gas available for low priority customers is uncertain and subject to delivery constraints. Within a pipeline, the gas available for low priority customers, L, is the difference between pipeline supply, S, and high priority demand, H. Over a seasonal planning period, the supply of gas from producers, pipeline storage stocks, and supplmental sources (naptha gasification, propane, and LNG) is reasonably certain, while high priority demand is temperature sensitive and, consequently, stochastic in the heating season (November through March). The value of gas to industrial customers depends on the reliability of supply if optimal adjustment to unanticipated gas deliveries is not instantaneous (i.e., some factors are regarded as fixed costs over the planning period). For example, firms with the option to install alternate fuel capability (storage and burner tip modification) have ex ante and ex post demands which differ depending on whether actual deliveries justify installation. Transportation of natural gas is economically limited to pipeline transmission; therefore, pipeline capacity and seasonal flows of high priority gas constrain low priority deliveries between distribution companies. Along a particular pipeline, gas can always be exchanged in the upstream direction by displacement sales, increased deliveries to an upstream distributor at the expense of downstream volume, but the converse does not hold. Exchange between pipelines are limited by similar constraints and the level of interconnection.[1/] The efficiency gain which may be achieved by allocating gas to high value users is obviously limited by constraints on the movement of gas through the pipeline system: pipeline capacity, interconnection, and dispatching flexibility. Analysis of two large eastern pipelines, Transcontinental and Tennessee Gas, indicates that only 25 percent of the potential gain from efficient national curtailment is achievable by reallocating gas within distribution company service areas. If gas can be costlessly reallocated along each pipeline individually then about 50 percent of the potential gain is achievable.[2/] Only if gas is freely exchangeable between pipelines can the entire benefit of efficient curtailment be obtained.

1/ In the U.S., interconnection between regional pipelines does not appear to be the limiting factor in pipeline exchanges.

2/ See Appendix II.

The percentage of the theoretical gains obtainable from efficient rationing, under existing transport constraints, is difficult, and in a certain sense, unnecessary to calculate. It turns out that the competitive bidding mechanism provides exactly the information on the regional marginal valuation of gas necessary for decentralized capacity expansion decisions. It is likely that only 25 to 50 percent of the potential efficiency gain can be achieved initially. After capacity is adjusted, using bidding data, a higher percentage efficiency gain may be achieved.

To simplify, we take the case where industrial gas demand is independent of the reliability of supply.[1/] We further assume, as illustrated in Figure 5.1, that gas demand is perfectly elastic at the alternative fuel price (p_i) for volumes up to target demand (q_i). Under these restrictive assumptions, the demand of an industrial customer in a given planning period is completely specified by two parameters (p_i, q_i): a single point in demand space. The problem is to establish a bidding mechanism which elicits accurate representation of demand from each industrial customer. One solution to this problem is the competitive auction proposed by Vickrey.[2/] The competitive auction allocates M commodities among N bidders (n M) according to the following fule: the M highest bidders are successful at the M+1st bid price. It is easily seen that there is no incentive to misrepresent valuation because successful bidders cannot affect the award price.[3/]

1/ This is the case where fixed costs associated with fuel use are negligible ex ante.

2/ Vickrey, W. "Counterspeculation, Auctions and Competitive Sealed Tenders", Journal of Finance 16, 1967.

3/ This is strictly true only if we take target demands as fixed; otherwise, manipulation of volume demands will affect award price.

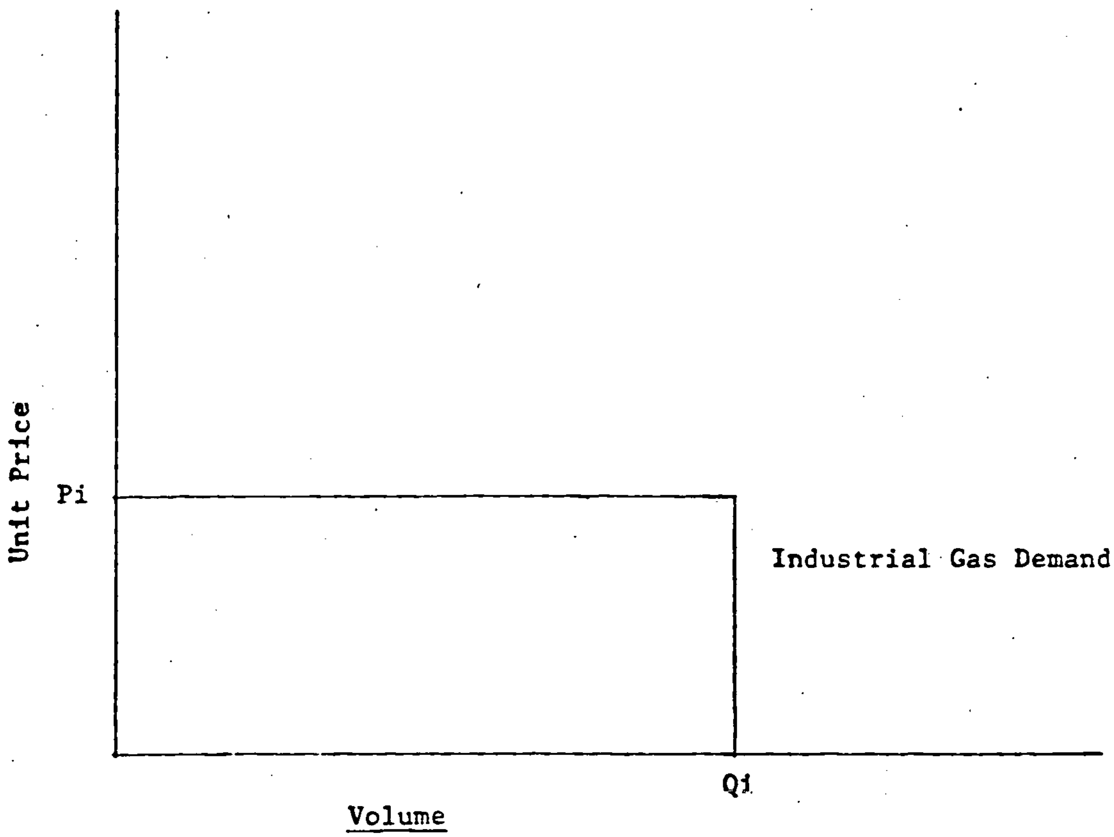


FIGURE 5.1: Industrial Gas Demand

The competitive auction may be shown to result in an efficient allocation revenue as the standard sealed bid auction when bidders are risk neutral.[1/] Smith has verified these theoretical results in experimental work.[2/] Under our demand assumption, industrial gas customers are risk neutral with respect to gas delivered at the demand price, so the competitive auction yields the same revenues as the standard sealed bid auction. Competitive auctions currently find use in certain Treasury bill sales, new equity issues in the French stockmarket (Bourse), and occasional sales of commercial paper.

The competitive auction could be implemented through the incremental pricing provisions of the NGPA. Alternative fuel cost would be defined as the bid, under competitive auction, of each low priority customer. Since the competitive auction is incentive compatible, industrial customers will bid true alternative fuel costs, including all coping and conversion costs; therefore, the use of competitive auction bids as the alternative fuel cost is consistent with the incremental pricing provisions of the NGPA. The frequency of bidding is limited by the interval between pipeline allocation decisions. Table 5.1 shows that dispatch decisions are made on a daily, monthly, or seasonal basis in the major interstate pipelines. In the absence of risk aversion, frequent bidding is desirable if the relative valuation of gas among industrial customers changes at short intervals. If risk aversion is important, then bidding should take the following form: separate bids for each month are submitted simultaneously prior to the relevant season, and gas allocations are determined for the entire season (month-by-month) in advance.

1/ Harris, M. and A. Raviv, "Allocation Mechanisms and the Decision of Auctions." Carnegie-Mellon GSIA Working Paper #5-78-79.

2/ Smith, Vernon, "Experimental Studies of Discrimination is Competition in Sealed-Bid Auctions." Journal of Business 40, 1967.

Table 5.1

CURTAILMENT PLANS OF THE 29 LARGEST INTERSTATE PIPELINE COMPANIES

PIPELINE COMPANY	CURTAILMENT PLAN	DATA BASE BREAKDOWN	ALLOCATION DECISIONS
Alabama-Tenn.	end-use	seasonal	seasonal
Algonquin	end-use	monthly	daily
Ark-La	end-use		
Cities Service	end-use	monthly	daily
Colo. Interstate	end-use	annual	daily
Columbia	end-use	seasonal	seasonal
Consolidated	end-use	seasonal	monthly
E. Tennessee	end-use	seasonal	seasonal
Eastern Shore	non-end-use		daily
El Paso	end-use		daily
Equitable	end-use		
Florida	non-end-use		daily
Michigan-Wisconsin	end-use	annual	
Midwestern	end-use	seasonal	monthly
Mississippi	non-end-use		daily
Nat's Fuel Gas Supply	end-use	annual	
Natural Gas PL, AM	pro-rata	annual	monthly
Northern	end-use		daily
Northwest	pro-rata		
Panhandle Eastern	end-use	monthly	
Southern	end-use		
Tennessee Gas	end-use	monthly	
Tennessee Nat. Gas	end-use	seasonal	
Texas Eastern	end-use	monthly	daily
Texas Gas Trans.	end-use	seasonal	
Transco	pro-rata	seasonal	
Transwestern	end-use	monthly	daily
Trunkline	end-use	seasonal	
United	end-use	monthly	daily

SOURCE: Prepared by ICF Incorporated from FERC Commission staff reports and telephone interviews

Bidding would be conducted on a pipeline-wide basis since this is consistent with the incremental pricing mechanism, and follows current dispatching juridiction. Ultimately, pipeline dispatching decisions should be merged for curtailment purposes to ensure that the value of gas to the marginal customer in each pipeline is equated.[1/] Where inter-connection facilities do not exist, the pipeline bid schedules provide exactly the information required to determine whether the benefits from connection exceed the capital and operating costs.

As noted above, efficiency gains achievable by efficient within-pipeline curtailment are on the order of one-half of potential gains. Moving gas between pipelines may be unrealistic in view of serious legal and political obstacles, including a longstanding Commission policy not to reward shortage pipelines, with gas from flush pipelines.

The mechanism for processing bids is straightforward: (1) The pipeline collects sealed bids from incrementally priced customers, (2) subtracts marginal transmission cost, depending on customer location, (3) arrays bids in order of descending price (bid plus marginal transmission cost), (5) uses this schedule to determine curtailment priorities over the relevant period, and (6) bills customers at the price of the highest unsuccessful bidder. Where risk aversion is important, these schedules, and the expected supply, may be publically released.[2/]

Bids represent offers to buy on a take-or-pay basis. Depending on pipeline dispatching flexibility, a white market could be established

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1/ This is the condition for efficiency. If marginal values differ, the opportunities exist for transferring gas from low to high value customers.

2/ Note that incentive-compatibility does not depend on privacy. However, collusion must be guarded against where small numbers are involved. In this case, bidders could be informed privately of their individual place in the pipeline curtailment queue without knowledge of rival bids.

where customers would buy and sell the rights to all or part of their position on the curtailment schedule. The pipeline dispatch office would serve as a broker for offers to buy and sell. Another variation is to set aside a limited volume of gas to be allocated on a spot auction basis, subject to delivery constraints.

The competitive auction is seen to elicit accurate bids, produce efficient curtailment, and yield the same expected revenues as the standard sealed bid auction. Moreover, since all customers are billed at a single price, and the award algorithm is trivial, the simple competitive auction is administratively attractive relative to other efficient mechanisms which may yield more revenues. When the demand assumption is relaxed, optimality results are less easily achieved. If demand elasticity is less than infinite, then the intuitive solution is to allow customers to bid more than one point on their demand schedule (i.e., a step function approximation to the demand curve). Under the conventional concavity assumptions on the production function, factor demands are negatively sloped and multiple bids are computationally identical to an increase in the number of bidders.[1/] If the demand curve is not monotonic, then the award mechanism becomes a more difficult integer programming problem.

Once multiple bids are allowed, the optimality property of the competitive auction is lost. Bidders can use multiple bids to, in effect, collude with themselves, lowering marginal bids to effect the award price on inframarginal bids. It can be shown that the potential gain from misrepresentation decreases with the number of bidders, and that multiple bid competitive

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1/ The derivative of the factor demand for gas with respect to the price of gas is: $\frac{1}{P} \frac{F}{G}$ where P=output price, F(·)= production function, and G=gas input. If the production is concave, then F/ G is negative.

auctions will closely approximate efficiency except where the number of total bids is very small.

Summary

We have shown, under simplified assumptions of industrial demand, that the simple competitve auction can be used to set accurate alternative fuel prices, as required by the incremental pricing provisions of the NGPA, as well as to provide efficiency in pipeline curtailment planning. Administrative costs appear to be low, and curtailment on the basis of competitive bid seems to be at least as legally defensible as existing procedures based on gas consumed by enduser category in 1972. We estimate that as much as half of the $1 billion annual curtailment loss could be eliminated by pipeline-wide competitive auctions, excluding net transportation costs. The state of Wisconsin has already implemented an experimnetal gas auction which, although differing from the competitive auction proposal, will provide useful information in the design of a national auction.

APPENDIX I

ECONOMETRIC MODEL OF THE INTERSTATE GAS MARKET

The model used to forecast the market-clearing price of gas and curtailments in the interstate market is described in this appendix.

Binding price controls in the interstate market have resulted in a disequilibrium between supply and demand for about ten years. Conventional equilibrium economic models are clearly inappropriate for this market. The problem is a special case of the switching regression model where we know the points in time at which the observations lie along the supply curve alone, and we have a measure of excess demand (curtailments). The model can be written as a log-linear supply curve:

$$(1)\quad \ln Q_t^s = \alpha_o + \alpha_1 \ln P_t^r + \alpha_2 \ln P_t^a + \alpha_3 \ln P_t^c + \varepsilon_t^s$$

$$\text{for } t = 1957, \ldots, 1978$$

and a log-linear demand curve:

$$(2)\quad \ln Q_t^d = \beta_o + \beta_1 \ln P_t^r + \beta_2 \ln P_t^d + \varepsilon_t^d$$

$$\text{subject to } Q_t^d = Q_t^s \qquad \text{for } t = 1957, \ldots, 1969$$

where Q^s = supply
P^r = average price of interstate gas
P^a = price of intrastate gas
P^c = average domestic price of crude oil
Q^d = demand
P^d = average price of distillate fuel oil
$\varepsilon^d, \varepsilon^s$ = normal, i.i.d. residuals
t = time subscript

Supply is expected to increase with the interstate price of gas and the price of domestic crude, in the latter case because much of the gas discovered is found in the process of oil exploration associated with crude reserves. The supply of gas in the interstate market should be inversely related to the price of gas in the intrastate market.

This model departs from others[1/] by using average gas prices in the supply equation. Typically, the change in supply is related to the marginal price of (new) natural gas dedicated to interstate commerce.

(3) $A_{t-1} = R_t - (1-\gamma)\ R_{t-1} - \alpha\ P^m_t$

where: A = reserve additions
R = reserves
P^m = marginal price of (new) natural gas.
γ = ratio of production to reserves

Equation (3) implies:

(4) $R_t = \delta \sum_{i=o}^{\infty} (1-\gamma)^i\ P^m_{t-i}$

and

(5) $Q_t = \gamma R_t = \gamma\delta \sum_{i=o}^{\infty}(1-\gamma)^i\ P^m_{t-i} = \gamma\delta\ \bar{P}^m_t\ (\gamma)$

where: $\bar{P}^m_t\ (\gamma)$ = geometric mean of $\{P^m_{t-i}\ 1\ i=0,1,2...\}$ with parameter γ.

The relationship between reserve additions and the marginal price of gas in equation (3) implies a relationship between quantity and the (geometric) mean of new natural gas in past years. It is easily shown that the average interstate price of gas is also a (geometric) mean of new natural gas prices:

(6) $P^r_t = (1+\beta)\ \bar{P}^m_t\ (\frac{\gamma+\beta}{1+\beta})$

where: β = annual rate of increase of marginal gas price (P^m)
$\bar{P}^m_t\ (\frac{\gamma+\beta}{1+\beta})$ = geometric mean of $\{P^m_{t-i}\ 1\ i=1,2,...\}$ with parameter $(\frac{\gamma+\beta}{1+\beta})$

For β small we have:

(7) $Q_t \doteq \frac{\gamma\delta}{1+\beta}\ P^r_t$

1/ P. MacAvoy and R. Pindyck. The Economics of the Natural Gas Shortage (1960-1980). 1975.

which shows that the current quantity of gas production will be related to the prevailing average price of interstate gas.

The demand equation depends on the <u>average</u> interstate price of gas because pipelines "roll-in" new gas supplies; in other words, distributors are charged the <u>average</u> wellhead price of gas plus transportation charges. Since gas is a close substitute for residual and distillate fuel oil, we expect the demand for interstate gas to increase with these product prices. Refined petroleum products are produced from a mixture of regulated domestic and foreigh oil and customers pay the composite (average) price. Customers therefore compare the average price of gas with the average price of refined petroleum products.

The supply and demand equations could be estimated by two or three stage least squares for the equilibrium (1957-1969) sample and the supply equation could be estimated by ordinary least squares for the disequilibrium (1970-1978) sample. However, no simple procedure for restricting the coefficients of the supply equation to be equal in both samples was discovered.

A second approach is to take advantage of our knowledge of excess demand to write the demand equation as:

$$(8) \quad \ln Q_t^{d*} = \ln(Q_t^s + E_t) = \beta_o + \beta_1 \ln P_t^r + \beta_2 \ln P_t^d + \Sigma_t^d$$

where: Q_t^{d*} = effective demand or "requirements"

E_t = excess demand (0 for 1957-1969)

Equations (1) and (8) are now in the classic equilibrium form and can be estimated by limited or full information maximum likelihood methods. However, our data on deliveries (Q^s) begins in 1963 while other price data is available back to 1957. We lose six observations out of 22 if Q^s appears directly in the model.

A third approach is to subtract equation (1) from equation (8) and estimate excess demand:

$$(9) \quad C_t \equiv \ln\left(1+\frac{E_t}{Q_t^s}\right) = (\beta_o - \gamma_o) + (\beta_1 - \gamma_1)\ln P^r + \beta_2 \ln P^d$$

$$- \gamma_2 \ln P^a - \gamma_3 \ln P^c + (\varepsilon^d - \varepsilon^s)$$

The advantage of the excess demand form of the model is that we know the value of excess demand is zero in all years prior to 1970 so that the full sample may be used. The dependent variable, C_t, is truncated at zero so that the residual does not have mean zero. We tried correcting for this bias using an approach which subtracts out the mean of the error term in successive iterations and corrects for heteroscedasticity.1/ The truncation correction procedure was not found to change the estimated coefficients by more than a few percent and was, accordingly, not used for the estimates reported.

Ordinary least squares estimation of equation (9) yielded estimates with the anticipated signs although the coefficient of P^r appeared to be biased towards zero. We postulated a simultaneity bias arising from the affect of curtailments (C_t) on FERC ratemaking policies (P_t^m). To test this we estimated the following lagged adjustment model of FERC ratemaking:

$$(10) \quad \ln\left(\frac{P^m}{P_{-1}^m}\right) = \lambda \ln\left(\frac{P^*}{P_{-1}^m}\right) + mC_t + \rho(P^* \cdot f^i) + \varepsilon_t^m$$

where: P^* = unregulated price of gas measured by the price of gas imports
f^i = fraction of gas supplies imported
λ = rate of adjustment

FERC's adjustment of the upper tier new gas price towards the unregulated world market level occurs at a rate of λ, and is influenced by the presence

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1/ This approach is suggested in G. Chamberlain. "Lecture Notes for Economics 2240a, 1977." Harvard University.

Table A2.2 displays the calculated values of P^{r*} for the three oil price scenarios.

of curtailments and the percentage of interstate gas imported. The interactive term $(P^{*} \cdot f^{i})$ assumption that the quantity and the price of imports should jointly affect the increase in the ceiling price set by FERC. Ordinary least squares estimation of equation (10) shows that the presence of curtailments does increase the rate at which the Commission adjusted interstate prices. Therefore, the estimated coefficient of $\ln P^{r}$ in equation (9) is likely to be affected by simultaneity bias coming from the price-setting equation (10).

An instrumental variables approach to the estimation of equation (9) was used to eliminate simultaneity bias. From equation (6):

$$(11) \quad \ln P^{r} \doteq \eta_1 \ln P^{m} + \eta_2 \ln P^{m}_{-1} + \eta_3 \ln P^{m}_{-2} + \eta_4 \ln P^{r}_{-2}$$

and from (10) and (11):

$$(12) \quad \ln P^{r} \doteq (\eta_2 + (1-\lambda)\ ) \ln P^{m} + \eta_1 \lambda \ln P^{*} + \eta_1 m C + \eta_1 \rho\ (P^{*} \cdot f^{i})^{-1} + \eta_3 \ln P^{m}_{-2} + \eta_4 \ln P^{r}_{-2}$$

From equation (12) the predetermined variables $(P^{m}_{-1}, P^{m}_{-2}, P^{r}_{-2})$ were used as instruments for P^{r} (i.e., correlated with P^{r} but uncorrelated with C).

The instrumental variables estimation of equation (9) is shown in Table A2.1. Equation (9) was used to forecast the level of curtailments in the interstate market and to solve for the market-clearing price. Setting $C_t=0$ and solving for P^{r} in equation (9):

$$(13) \quad \ln P^{r*} = -\frac{(\beta_0 - \alpha_0)}{(\beta_1 - \alpha_1)} - \frac{\beta_2}{\beta_1 - \alpha_1} \ln P^{d} - \frac{\alpha_2}{(\beta_2 - \alpha_1)} \ln P^{a} - \frac{\alpha_3}{(\beta_2 - \alpha_1)} \ln P^{c}$$

where: P^{r*} = estimated market-clearing price of gas

Differentiating (13) gives the rate of increase in the market-clearing price of interstate gas:

$$(14) \quad \dot{P}^{rx} = -\frac{\beta_2}{(\beta_1 - \alpha_1)} \dot{P}^{d} - \frac{\alpha_2}{(\beta_1 - \alpha_1)} \dot{P}^{a} - \frac{\alpha_2}{(\beta_1 - \alpha_1)} \dot{P}^{c}$$

where: $\dot{P}^{r*}$ = rate of increase of the market-clearing price
$\dot{P}^{d}$ = rate of increase of distillate price
$\dot{P}^{a}$ = rate of increase of intrastate gas price
$\dot{P}^{c}$ = rate of increase of average price of domestic crude.

INSTRUMENTAL ESTIMATES

DEPENDENT VARIABLE: LCURT2

INSTRUMENTAL VAIABLES...

C LDO LPIO LDMCRUDO LPIOQ1 LMP1 LMP2 LP2

SUM OF SQUARED RESIDUALS =	.152379E-01
STANDARD ERROR OF THE REGRESSION =	.308605E-01
MEAN OF DEPENDENT VARIABLE =	.592796E-01
STANDARD DEVIATION =	.104702
NUMBER OF OBSERVATIONS =	21.
SUM OF RESIDUALS =	.238419E-06
DURBIN-WATSON STATISTIC (ADJ. FOR O. GAPS) =	1.4146

RIGHT-HAND VARIABLE	ESTIMATED COEFFCIENT	STANDARD ERROR	T STATISTIC
C	-.651486	.390539	-1.66817
LPO	-.321430	.167324	-1.92101
LDO	.750283	.249508	3.00705
LPIO	.342652	.108830	3.14849
LDMCRUDO	-.645337	.302269	-2.13498

ESTIMATE OF VARIANCE-COVARIANCE MATRIX OF ESTIMATED COEFFICIENTS

	C	LPO	LDO	LPIO	LDMCRUDO
C	.152521	.616989E-01	-.858906E-01	-.358433E-01	.112945
LPO	.616989E-01	.279972E-01	-.286764E-01	-.170369E-01	.444210E-01
LDO	-.858906E-01	-.286764E-01	.622541E-01	.143720E-01	-.639682E-01
LPIO	-.358433E-01	-.170369E-01	.143720E-01	.118441E-01	-.284855E-01
LDMCRUDO	.112945	.444210E-01	-.639682E-01	-.284855E-01	.913664E-01
	1	2	3	4	5

TABLE A2.1 EXCESS DEMAND EQUATION

Key

LCURT2	= ln (excess demand)
C	= constant term
LPO	= ln (price of interstate gas)
LDO	= ln (price of distillate fuel oil)
LPIO	= ln (unregulated gas price, measured by the price of gas imports)
LDMCRUDO	= ln (price of domestic crude)
LMP1	= ln (new contract gas price) logged one period
LMP2	= LMP1 logged one period
LP2	= LPO logged two periods
LPIOQ1	= interaction term. product of LPIO and percentage of gas imported

TABLE A2.2 ESTIMATED RATE OF INCREASE OF THE MARKET-CLEARING PRICE

	Low Case	Middle Case	High Case	Price Level January, 1980 ($/MMBTU)
$\dot{P}^a$	.038	.038	.038	2.60
$\dot{P}^d$	0	.038	.076	6.55
$\dot{P}^c$	0	.038	.076	3.41
$\dot{P}^{r*}$	.041	.053	.065	1.74

Increasing oil prices have two effects: (1) to increase the demand for natural gas as a substitute fuel, and (2) to increase oil exploration and, indirectly, the supply of gas from associated reserves. The market-clearing price of gas rises with increasing oil prices because the estimated demand effect is larger than the supply effect.

The market-clearing price for January, 1980 was calculated from equation (13) using the observed price levels of distillate, domestic crude oil, and the NGPA ceiling for intrastate gas[1/] (Table A2.2). The market-clearing price was forecast through 1985 under three oil price scenarios using the estimated rates of increase shown in Table A2.2.

The average price of interstate gas is a weighted average of the price of old and new contract gas. From equations (3) and (5), the quantity of gas produced in each period can be separated into production from old and new reserves:

$$(15) \quad Q = [(1-\gamma)Q_{-1}] + [\gamma A]$$

1/ The price of gas imports was used to measure the unregulated price of gas prevailing in the intrastate market. The price of gas imports in October, 1978, just prior to the enactment of the NGPA, was escalated at the ceiling price rate to estimate the intrastate gas price under the NGPA. Data on the average and new contract price of intrastate gas is unfortunately unavailable in aggregate form.

$$(16)\quad P^r = \frac{(1-\gamma)Q_{-1} \quad P^r_{-1} + \gamma A \quad P^m}{Q}$$

which can be rewritten as:

$$(17)\quad P^r = (\frac{1-\gamma}{1+\Theta})P^r_{-1} + (\frac{\Theta+\gamma}{1+\Theta})P^m$$

where is the annual rate of increase in production. Since the price of new gas, P^m, is known during the NGPA control period (1978-85), the average interstate price of gas can be forecast from equation (17) under different parameter assumptions for γ and Θ.

The average price projections in Table 4.2 are estimated from equation (17) allowing the reserve to production ratio to vary from 7 to 12. The rate of production increase, Θ, varies across oil price scenarios because the price of domestic crude affects production according to equation (1): the difference in Θ between the low and middle scenarios is .025, and between the low and high scenarios is .05.

Table A2.3

Parameter Values for Average Price Projections

γ		Θ		
Low	High	Low Case	Middle Case	High Case
.07	.12	0	.025	.05

APPENDIX II

Economic Cost of Curtailment

Appendix II Economic Cost of Curtailments

This appendix provides the analysis to support the curtailment cost estimates cited in Section 4.3. The efficiency losses arising from the misallocation of gas under FERC curtailment plans are estimated.

Pipeline Curtailment

Table A2.1 shows deliveries and curtailments in the 1977/78 heating season. Curtailments in the interstate market amounted to 1,360 Bcf out of a total demand[1/] of 10,020 Bcf. The aggregate allocation of curtailments was 570 Bcf to commercial and industrial customers with "firm" contracts, and 790 Bcf to industrial and utility customers under interruptible contract. While interruptible customers were curtailed more severely than firm, 44 versus 7 percent, they nevertheless received deliveries of 990 Bcf. The value of this gas is reasonably estimated by the price of residual fuel oil since interruptible customers are principally large boiler users with low cost alternative fuel use and storage capability. The value of gas to firm customers curtailed varies from resid to more expensive alternative fuels such as distillate. The highest value occurs in cases where alternative fuel is unobtainable. The delivery of gas to low value interruptible customers when higher value firm customers are curtailed represents an efficiency loss.

1/ Demand is given by high priority usage, excluding hook-up bans, plus firm and interruptible contracts with low priority customers. In practice, all low priority contracts are now interruptible.

TABLE A2.1

DELIVERIES AND HEATING SEASON CURTAILMENTS

1977/78

CATEGORY	DELIVERIES (Bcf)	CURTAIL-MENT (Bcf)	REQUIRED (Bcf)	CURTAIL-MENT %
Residential	3510	50	3510	0%
Commercial	1590	50	1640	3.0%
Industrial	2440	590	3030	19.5%
Utility	1000	700	1700	41.2%
Other	130	20	150	13.3%
TOTAL	8660	1360	10,020	13.6%
Firm	7670	570	8,240	6.9%
Interruptible	990	790	1,780	44.4%

Source: EIA. "Natural Gas Deliveries..." Dec. 1978.

The size of the efficiency loss can be estimated directly from data on alternative fuel use shown in Table A2.2. Here is may be seen that 335 Bcf-equivalent of expensive alternative fuels (i.e., butane, distillate, propane, electricity and no alternative fuel) were consumed during the heating season by curtailed customers. If some of the 990 Bcf delivered to interruptibles, valuing gas at resid, is moved to curtailed firms with high alternative fuel costs, a net gain in efficiency results. The efficiency gain is equal to the difference in the cost of alternative fuels between customers exchanging gas less marginal transport costs.[2/] Transport costs are initially neglected in these estimates, and considered at the end.

The price differential between alternative fuels is calculated in Table A2.3 from July 1979 data. Average wholesale prices are quoted with the exception of electricity where the average industrial rate is shown. Electricity is the most expensive alternative fuel, followed by distillate, propane, low sulfur and high sulfur resid. To calculate price differentials between fuels we assume that interruptible gas is valued half at high, and half at low sulfur resid.[3/]

Table A2.4 shows the results of the efficiency loss analysis using the price and quantity data on alternative fuel use. The analysis is particularly sensitive to the assumed valuation placed on gas by curtailed industrial customers without available alternative fuels.

2/ Technically, the real resource cost of alternate fuels delivered should be used in the analysis of efficiency gains from gas reallocation. Oil regulation distorts refined product prices, but since only the price differential is needed for this analysis we may hope that regulatory bias is negligible.

3/ Upper and lower bounds could be calculated by alternately assuming 100% low sulfur and 100% high sulfur resid usage.

TABLE A2.2

Alternate Fuel Use--1977-78
(Bcf equivalent)

	Non-heating Season	Heating Season	Total Year
No alternate fuel	5	16	21
Electricity	N.A.	17	17[a]
Propane	23	45	68
Distillate	178	241	419
#4	N.A.	16	16[a]
SUBTOTAL	206	335	541
Resid	948	705	1653
Coal	224	195	419
Other	N.A.	83	83[a]
Supplemental Gas Purchases	N.A.	8	8[a]
TOTAL	1378	1326	2704

[a]These figures do not include non-heating season alternate fuel use (if any).

Source: EIA "Natural Gas Deliveries . . . ," Dec. 1978.

TABLE A2.3

PRICES OF ALTERNATE FUELS--1979
($/MMBtu in 1979 $)[1]

Fuel	Price	Price Differential Over Average Resid
Electricity	$8.62	$5.52
Propane	3.37	.27
Distillate	4.74	1.64
Low Sulfur Resid	3.42	-
High Sulfur Resid	2.79	-
Average Resid	$3.10	$ 0

[1]Wholesale prices, August 1979.

TABLE A2.4

NATIONAL ESTIMATE OF ECONOMIC LOSS
DUE TO CURTAILMENT PLANS 1977-78
(millions of 1979 $)[1]

Alternate Fuel	Heating Season			Non-Heating Season			Total
	Curtailed (Bcf)	Price Differ. ($/Mcf)	Loss ($)	Curtailed (Bcf)	Price Differ. ($/Mcf)	Loss ($)	Loss ($)
Electricity	17	5.52	94	NA	5.52	-	94
Propane	45	.27	12	23	.27	6	18
Distillate	257	1.64	421	178	1.64	292	713
SUBTOTAL	319		527	201		298	825
No Alt. Fuel	16			5			
Low[2]		6.00	96		6.00	30	126
High		25.00	400		25.00	125	525
TOTAL	355		623-927	206		328-423	951-1350

[1]Efficiency losses calculated assuming costless reallocation of gas from deliveries to interruptible customers to curtailed customers with alternate fuels valued at or above distillate.

[2]Estimated range of value of gas to customers curtailed without alternate fuel (price differential above average resid price)

We would not expect the value to much exceed the cost of electricity when the curtailment is anticipated, because work rescheduling and other contingent plans may be arranged. Only where the curtailment is sudden and unexpected would the value of gas incorporate a scarcity premium on the order of our upperbound estimate of $25/Mcf. Using upper and lower bound estimates of the value of gas to customers without alternative sources, the curtailment efficiency loss is shown to range $800 to $1600 million per year.

These estimates do not consider the marginal cost of moving gas between end users to achieve efficiency. A first cut analysis of the transport costs involved is made by estimating the proportion of the potential efficiency gain which could be achieved by reallocation within: (1) local distribution companies only, (2) pipelines only, and (3) between pipelines. Table A2.5 shows the results of such analysis for two eastern pipelines: Transcontinental and Tennessee Gas.[4/] This analysis shows that approximately 25 percent of the potential benefit from efficient curtailment can be achieved by reallocations within local distribution companies which incur no incremental transport costs. Another 25 percent of the potential efficiency gain can be obtained by reallocating gas between distribution companies along individual pipelines. As noted previously, gas transport in the upstream direction, a displacement sale, saves transport charges which would otherwise be incurred in moving gas further down the pipeline. On the other hand, transfers in the downstream direction may cost as much as 50¢/Mcf (Texas to Massachusetts), or more if pipeline capacity is constrained. How costly reallocation within

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4/ These estimates were made, using pipeline curtailment data, by Paul Leiby, research assistant, with staff from ICF, Inc.

TABLE A2.5

ECONOMIC LOSS DUE TO CURTAILMENT
ON TRANSCO AND TENNESSEE PIPELINES
(millions of 1979 $)

Scope of Reallocation	Heating Season 1977/78		Non-Heating 1977/78		Total	
Within Dist. Co's.[1]						
Transco	$3.8	26%	$5.3	19%	$9.1	22%
Tennessee Gas	4.7	32	7.7	28	12.4	29
Within Pipelines[2]						
Transco	8.9	61%	15.4	56	24.3	56%
Tennessee Gas	11.1	72	17.8	64	28.9	68
Between Pipelines[3]						
	$14.7	100%	$27.6	100%	$42.2	100%

[1]Includes 9 largest distribution companies on the Transco pipeline and 11 largest distribution companies on the Tennessee pipeline. Efficiency losses are calculated by reallocating gas delivered to interruptible customers to curtailed customers with alternate fuels valued at or above distillate (no. 2) fuel oil.

[2]Efficiency losses calculated assuming costless transport of gas along individual pipelines.

[3]Efficiency losses calculated assuming costless transport of gas between Transco and Tennessee pipelines.

pipelines will be depends on the net direction of gas reallocation (i.e., upstream versus downstream). The cost of moving gas between pipelines is hardest to estimate. Fully half of the benefits of efficient curtailment come from the transfer of gas from well-supplied to shortage pipelines. The legal restraints are significant and the extent of pipeline interconnection is difficult to determine. Based on these considerations, a net efficiency gain of one-half the amount of the potential benefits, shown in Table A2.4, is a reasonable estimate.

APPENDIX III

Natural Gas Industry Data Sources

Natural Gas Industry Data Sources[1/]

The following table indicates written sources of natural gas industry data. Each column corresponds to a data type. Each row corresponds to a particular degree of aggregation of data, by geographic unit and time period. The numbers in the table refer to the following sources:

1. FPC/FERC Form 2 Filings (available at FERC Office of Public Information).

2. FPC/FERC Form 16 Filings (available at FERC OPI).

3. FPC, Sales by Producers of Natural Gas to Interstate Pipeline Companies (annual, published for public, available at Baker Library).

4. FPC, Statistics of Interstate Natural Gas Pipeline Companies, (annual, published for public, available at Baker Library).

5. H. Zinder and Assoc., Summary of Rate Schedules of Natural Gas Pipelines, (bi-annual, available at FERC library).

6. American Gas Assoc., Gas Facts (annual, available at Baker Library).

7. American Gas Assoc., Gas Industry Operations (quarterly, available at Baker Library).

8. Brown's Directory of North American Gas Companies (annual, available at FERC Library).

9. FPC, later DOE/EIA, Natural Gas Deliveries and Curtailments to End Use Customers (annual, published for public, available in DOE Library.
   * indicates data available in 1977 and later editions only).

10. FERC, Office of Pipeline and Producer Regulation Systems Analysis Branch, Natural Gas Deliveries, Curtailment and Alternate Fuel Offsets of Curtailment, April 1974 through March 1977 Actual and April 1977 through March 1978 Projected, DOE/FERC-0018 (published for public, available at DOE Library).

11. FEA Form G-101, FPC Form 69, and EIA Form 50 Filings. (See FERC Library).

1/ Compiled by Paul Leiby, Reasearch Assistant.

Degree of Data Aggregation	Gas Sales	Gas Price	Curtail-ment	Alt. Fuel Use Under Curtailment	Vol. of stored gas	Type of Stor-age	Rates
A. Annually							
for all U.S.	6,7	6,7	9*	9*,.10	6		
by Region	7	7	9*				5
by State	6	6	8*, 9*	10	6	6,8★	
by Individual Pipeline Co.	1,4	1,4	2,8★		1,4	1,8★	5
by Individual Distrib. Co.	8	8	2	11	8	8	8
by Enduse Customer Type†	1,4,6,7,8	4,6,8	9*				8
by Enduse Service Type††	1,2,8	8	2,9*	10			5
B. Seasonally							
for all U.S.	6,7	6,7					
by Region	7	7					5
by State							
by Individual Pipeline Co.							5
by Individual Distrib. Co.	1						
by Enduse Customer Type	7	7					
by Enduse Service Type							5
C. Monthly							
for all U.S.	6	6	9*	9*,10			
by Region			9*				
by State			9*	10			
by Individual Pipeline Co.	1		2		1	1	
by Individual Distrib. Co.			2	11			
by Enduse Customer Type			9*				
by Enduse Service Type			2,9*	10			

* Covers only heating season (November-March).

★ For 1977 and later editions only.

† Enduse Customer Types are Residential, Commercial, and Industrial.

†† Enduse Service Types are Firm and Interruptible.