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THE ECONOMICS OF THE NATURAL GAS CONTROVERSY

A STAFF STUDY

PREPARED FOR THE USE OF THE

SUBCOMMITTEE ON ENERGY

OF THE

JOINT ECONOMIC COMMITTEE
CONGRESS OF THE UNITED STATES

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LETTERS OF TRANSMITTAL

September 15, 1977

To the Members of the
Joint Economic Committee

Transmitted herewith for the use of the Joint Economic Committee and other Members of Congress is a staff study done for the Subcommittee on Energy entitled "The Economics of the Natural Gas Controversy." The study is intended to provide useful background data and analysis to facilitate consideration of the many complex issues concerning natural gas now before the Congress. It is my hope that Members will find it helpful.

The views expressed in this document are those of the author and do not necessarily correspond to the views of Members of the Committee.

Richard Bolling,
Chairman, Joint Economic Committee

September 14, 1977

Honorable Richard Bolling
Chairman, Joint Economic Committee
Congress of the United States
Washington, D. C. 20510

Dear Mr. Chairman:

I am pleased to transmit herewith a staff study prepared for the Subcommittee on Energy entitled "The Economics of the Natural Gas Controversy."

This document assembles important information relating to decisions on the continuation of natural gas price ceilings and other major issues. It contends that the price elasticity of gas supply is quite low. This is due to the prevailing view that U.S. gas resources have been substantially depleted and that only limited amounts remain to be tapped even at higher prices. It indicates also that limitations on gas prices will affect primarily the values of mineral rights and other scarcity values embedded in the gas industry's cost structure and not the returns to risktaking itself in the development and production of gas.

The study also indicates that while the price elasticity of natural gas demand is low in the short run it rises to higher levels over several years. Thus, a legally mandated schedule of gradual future price increases would put consumers on notice to consider higher future gas prices in choosing new energy-using equipment without burdening the economy with large, inflationary price increases in the early years during which little conservation can be effected without privation and disruption.

Furthermore, the study shows that the immediate and unqualified deregulation of natural gas prices could cost the economy as much as $21 billion in 1978; $30 billion in 1979; and $35 billion by 1980. This would be about $25 billion more in 1980 than would be paid under a continuation of current FPC regulation. By comparison, energy price increases from 1973 to 1975 added some $58 billion annually to total energy costs. It is widely agreed that this earlier energy price rise contributed heavily to the alarming inflation and the deep recession of that period.

Finally, this staff study deals with a number of important technical issues that must be addressed in any reform of natural gas regulations such as (1) the level at which a new national gas price ceiling should be set; (2) the definition of "new" natural gas; the need to limit price adjustments for gas already flowing under existing contracts; (4) the manner in which higher new gas prices are to be incorporated into gas utility rates; (5) protection of intrastate gas consumers, and so on.

The Subcommittee is extremely grateful to the Congressional Research Service of the Library of Congress for making Lawrence Kumins, the author of this document, available temporarily to the Joint Economic Committee staff. Naturally, the views contained in the study are those of the author and not necessarily those of the Members of the Subcommittee or of the Congressional Research Service.

Edward M. Kennedy
Chairman, Subcommittee on Energy

September 13, 1977

Honorable Edward M. Kennedy
Chairman, Subcommittee on Energy
Congress of the United States
Washington, D. C. 20510

Dear Senator Kennedy:

Transmitted herewith is a staff study entitled "The Economics of the Natural Gas Controversy." It attempts to marshall and analyze the background data necessary for well informed decisions on natural gas issues now before the Congress.

The study was prepared by Lawrence Kumins, whose services were made available for several months to the Committee staff by the Environmental and Natural Resources Policy Division of the Congressional Research Service, Library of Congress. Substantial assistance in this work was provided by William A. Cox of the Committee staff. Manuscript preparation was handled by Beverly Park.

John R. Stark
Executive Director
Joint Economic Committee

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CONCLUSIONS

This paper has been prepared to provide information and discussion on the economies of the natural gas pricing issue. It describes the historical experience under Federal Power Commission price controls, potential future supplies of gas, and methods for curbing demand. The potential macroeconomic effects of natural gas price increases are dealt with along with measures by which the natural gas pricing dilemma can be resolved.

Some of the more important points made in the study are:

o The early years of Federal Power Commission (FPC) regulation probably resulted in prices higher than would have been the case without regulation. However, the 1960s saw real prices decline as a result of controls.

o Savings on the order of $6.7 to $12.0 billion annually accrued to both inter and intrastate gas users during the 1960s as a result of controls.

o New reserve additions dropped sharply after 1967, and production declines followed in 1973. Drilling activity, especially for gas wells, has risen sharply since 1973.

o The existing regulatory structure will result in substantial rises in gas prices in the foreseeable future. Under prevailing tariff rulings, consumers eventually will pay $10 billion per year more than they are paying now for today's supply of gas.

o The lower 48 States and readily accessible offshore areas already have been extensively exploited. Recent estimates see much lower potential reserves discovered compared to just a few years ago. Estimates of possible production levels have been consistently reduced, even at high projected prices.

o Production economics are such that higher prices beget higher costs. Potential excess profits in the producing sector are, to a significant extent, captured by the equipment and labor supply sectors and mineral rights owners.

o Expectations of increasing gas prices create a situation in which gas left in the ground is perceived as a better investment than cash in the bank. An incentive to withhold production is thereby created. There is circumstantial evidence that producers recently have been responding to this incentive and withholding production.

o At today's prices, only wells with very high costs and low potential production will not be produced. No substantial finds will be rendered uneconomic by maintaining price constraints within today's price range.

o The profitability of new energy production in the United States remains higher and more secure than in virtually any other part of the world.

o An unambiguous statement that gas price increases will be limited to moderate rates below the returns on other investments is essential to end the incentive to withhold production. Such a clarification of price policy must be a primary objective of

Congress as it considers legislation reforming natural gas regulation.

o The demand for gas is not very price sensitive, implying that price is a relatively poor conservation tool, especially in the short run.

o In the face of rigid constraints on domestic supply and the very limited availability of natural gas imports, gas prices in the absence of controls could go to extremely high levels. High prices for domestic production can be justified, however, only to the extent that they serve U.S. national purposes such as reduced import dependency.

o After the 1973 oil embargo, energy prices rose by $58 billion over a two-year period, causing perhaps one-half of the inflation of 1974 and 1975.

o The immediate deregulation of gas prices would cause similar, although smaller, inflationary effects. Under deregulation, the Nation's gas bill would be about $25 billion per year higher than under extension of the regulatory status quo.

o Because of clauses in many existing natural gas contracts for large volumes of gas stipulate price renegotiation in the event of deregulation, this action would increase prices on old as well as new gas, unless measures are specifically mandated to proscribe this. Old gas prices would then gravitate toward the upper price level.

o There are numerous ways in which the potential inflationary impact can be both minimized and spread out over time. The most important options are:

(i) A ceiling price which would prevent scarcity pricing of gas;

(ii) A tight definition describing what gas is eligible for the higher price. This will place the incentive strictly on the discovery of truly new gas in locations other than in currently known producing fields;

(iii) Strong measures to ensure that producers continue to deliver old gas at old gas prices;

(iv) Measures to protect intrastate gas users from higher energy prices;

(v) Unification of the national gas market and abolition of the inter-intrastate dichotomy, is desperately needed in order to achieve a resemblance of proper allocation.

I. THE CURRENT SITUATION AND HOW IT DEVELOPED

Passed in 1938, the Natural Gas Act 1/ granted the Federal Power Commission (FPC) power to regulate interstate sales of natural gas for resale. As initially interpreted by the FPC, this meant control of the charges of interstate pipelines selling gas to distribution companies. Only the pipelines' tariffs for transporting gas were regulated; wellhead prices paid to gas producers were excluded, in this early interpretation, by Section 1 (b), which states "The provisions of this act . . . shall not apply . . . to the production or gathering of natural gas".

Mainline direct sales to end users of interstate pipelines also were excluded and remain outside FPC purview today. Most local distribution of natural gas is an intrastate activity and falls under the jurisdiction of State public utility commissions.

A piece of New Deal legislation, the Natural Gas Act had as its goal to ensure that consumers paid "fair" prices for gas sold by a natural monopoly (the pipeline industry), which was just beginning to develop at the time of its passage. At that time wellhead prices were extremely low because of the Depression and the fact that the interstate pipeline system, which was the main customer, was in its infancy. In many producing areas, monopsonistic situations existed, where single pipeline buyers were able to dictate field prices.

The FPC operated under this interpretation of the Natural Gas Act until 1954, when the Supreme Court ruled in the Phillips 2/ case that the FPC indeed had regulatory responsibility for production and gathering. The case arose out of a dispute between Phillips Petroleum, the Wisconsin Public Service Commission (PSC) and the Detroit Corporation Counsel, stemming from a 1945 contract between Phillips and the Michigan-Wisconsin Pipeline. Renegotiation in 1949 raised the wellhead price from 5 cents to 8-1/2 cents per thousand cubic feet (mcf). The contract's inflation adjustment clause was changed so that the price paid to Phillips was tied to the price received by Michigan-Wisconsin from distribution companies at the city gate. In response to complaints by Detroit and the Wisconsin PSC, the FPC scheduled hearings inquiring into the rate's reasonableness. The agenda was then changed, however, to consider only the question of the FPC's jurisdiction. 3/ When the Commission refused to take jurisdiction, the Wisconsin PSC brought suit in the D.C. Court of Appeals, which reversed the FPC in May 1953. The Supreme Court upheld the finding that Phillips was indeed a natural gas company within the Act's intent and that its sales in interstate commerce were subject to FPC jurisdiction.

Thereafter, the FPC began to regulate wellhead prices on a producer-by-producer basis. However, congressional action to lift this court-imposed mandate was anticipated. In 1956, Congress passed the Harris-Fulbright Act to do this, but the Act was vetoed by President Eisenhower, who, although agreeing with its principles, felt compelled to veto because of "arrogant lobbying" for its passage and allegations of producer vote buying. 4/ While other attempts were made to remove producer regulation, none reached the floor of either House of Congress again until 1975.

Prices Under FPC Regulation

The FPC began to apply to wellhead gas pricing the same regulatory procedures used in electric utility and gas pipeline ratemaking. In practice, however, only 11 full-scale producer rate cases were heard during the 1954-1960 period. All except one (which never was concluded) showed producers' revenues to be less than costs, implying either that oil was cross-subsidizing gas production or that the cost data for gas were exaggerated. In any event, gas production continued to expand. Within the pricing guidelines established by these proceedings, the FPC accepted about 11,000 rate schedules from 3,372 producers between 1954 and 1960. 5/ About 33,000 supplements to these schedules had been filed by 1960, and a substantial backlog of cases existed in which rates had been suspended pending hearings.

Due to the hearing backlog, and because of the futility of setting rates which were often above contract prices, the Commission abandoned rate making for individual producers and turned to dealing with broader, geologicially homogeneous producing areas. Not only was this change intended to consolidate backlogged rate cases, but it would determine fair gas prices based on financial requirements of broad industry segments rather than on individual firms' costs of service. In 1961 the FPC held the Permian Basin Area Rate Hearing, the first of

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this nature. This proceeding was culminated in 1965 with a ruling which set 16.5 cents per mcf. 6/ as the appropriate area rate. A lower price was set for old gas contracted for sale in the interstate market before 1961, establishing a multitiered pricing system based on the vintage of the well. Other area rates were subsequently set, and during the latter 1960s and early 1970s, rates for gas from new wells in the various areas were increased.

Problems stemming from a complex set of different rates for the various producing areas and vintages led the FPC in 1974 to attempt simplification by abandoning the area rate concept in favor of a single nationwide rate. This rate was first set at 42 cents per mcf. for new gas discovered after January 1, 1973. The new gas rate was adjusted to 52 cents per mcf. in 1975, plus an inflation adjustment of one cent per mcf. per year.

On July 27, 1976, the FPC issued Opinion 770, which set a new and radically higher national rate of $1.42 per mcf. for new gas developed after January 1, 1975. The 1973-1974 rate was increased from 52 cents to 93 cents per mcf. (as modified by Opinion 770A in November 1976), and older gas from expiring contracts was allowed to be continued in interstate commerce at 52 cents. All rates are subject to adjustments for Btu content, State severance tax reimbursement and gathering allowances.

Table 1 shows average gas prices paid to producers under the various ratemaking approaches in current and constant dollars. One observes that the period of individual

Table 1. New Gas Contract Prices
1953-1969

Year	New Interstate Contract Price (cents per Mcf.)	New Contract Price in 1958 Dollars
1953	13.3	15.1
1954	11.7	13.1
1955	14.4	15.8
1956	14.8	15.7
1957	16.9	17.3
1958	18.6	18.6
1959	18.4	18.1
1960	18.2	17.6
1961	17.9	17.1
1962	17.5	16.5
1963	17.0	15.9
1964	16.2	14.9
1965	17.4	15.7
1966	17.4	15.3
1967	18.6	15.8
1968	19.0	15.5
1969	19.7	15.4

Source: Patricia E. Starratt and Robert M. Spann, "Alternative Strategies for Dealing with the Natural Gas Shortage in the United States," in Edward W. Erickson and Leonard Waverman, eds. The Energy Question: An International Failure of Policy (Toronto and Buffalo: University of Toronto Press, 1974), Vol. 2, "North America," p. 31.

producer regulation was generally characterized by rising wellhead prices. By 1961, as the area rate approach began to replace producer regulation, prices -- especially in constant dollars -- began to decline. This decline continued throughout the 1960s. In order to put the decline of real gas prices into the proper context, it is useful to note that unregulated oil prices also tended to decline in constant dollars. This occurred despite government efforts to support oil prices through import quotas and State prorationing.

Evaluating Regulatory Performance, 1954-1972

It is hard to evaluate whether or not the Supreme Court did the correct thing in requiring the FPC to regulate wellhead gas prices. It also is hard to assess whether the FPC responded with the correct regulatory approaches. Critics assert that utility-type regulation was inappropriate for the gas-producing industry, because the gas field operators were highly competitive. Gas production (in contrast with gas distribution) is not a utility-type activity. Those favoring regulation have held, as did the Supreme Court, that such controls were necessary to assure fair prices to consumers, because of alleged market power on the part of gas producers and also because of the presumed bargaining weakness of the pipelines due to their more or less automatic entitlement to pass through their gas procurement costs to customers. In any event, one can assess the extent to which the price set by the FPC deviated from competitive levels by dividing the pre-1970 period into two parts:

(1) During regulation's initial six years, it would appear that the FPC did not hold prices appreciably below market levels. In its early years, indeed, the Commission's role in field markets may have diminished the monopsonistic power exercised by pipelines in some producing areas, resulting in higher prices than would have occurred otherwise.

(2) Some time between 1962 and 1968, the demand for gas (which developed in step with the pipeline system) probably reached a level sufficiently greater than supply for gas prices, had they been unregulated, to have converged to Btu equivalence with oil. This would have meant that industrial users -- the first to switch among substitute fuels -- would have bid the price up to their oil-fuel equivalent.

During each of these years, industrial sales averaged 35 cents per mcf., of which about 20 cents were for transport and distribution. Wellhead prices averaged less than 15 cents per mcf. (i.e., per million Btus). Industrial bulk fuel users could purchase distillate fuel oil at 15 cents per gallon or roughly $1 per million Btus. Residual fuel averaged about 70 cents per million Btus. Given these oil fuel prices, the potential existed during this period for <u>burner-tip</u> gas prices to rise from 35 cents to between 70 cents and $1. Wellhead prices, therefore, could have risen from an average of 15 cents to between 50 and 80 cents, except where contracts between producers and pipelines prohibited increases.

It is hard to know how contracts signed in the 1940s and 1950s would have been honored in the absence of regulation, as excess supplies of gas disappeared. No doubt many would have been broken or renegotiated. This price boost of 35 cents to 65 cents per mcf., if applied to all flowing gas during the 1960s. could have cost consumers between $6.7 and $12.0 billion yearly during the latter 1960s. These sums represent savings which accrued to both intrastate and interstate gas users, inasmuch as interstate prices tended to influence intrastate prices during this period.

Whether or not regulation was useful before 1973, the rise of OPEC placed the matter in an entirely new light. Whether the domestic gas industry is competitive or not is no longer relevant, because all uncontrolled energy prices are under the dominant influence of the OPEC cartel. Until energy supplies are forthcoming in sufficient quantity from non-OPEC sources, competitive prices will not exist. The question is simply whether the U.S. Government or a combination of foreign governments should set prices for domestic energy.

Trends In Production and Reserves

The natural gas industry grew rapidly in the 1950s and 1960s. Miles of pipeline and main have doubled since the Phillips decision; revenues increased from $3.5 billion in 1954 to $13.0 billion in 1972; and sales rose from 6.7 trillion cubic feet (tcf.) annually to a 1972 high of 17.1 tcf.

Against this backdrop of a seemingly healthy and expanding industry, however, the reported gas reserves underpinning this growth were beginning to shrink. Proven natural gas reserves in the "lower 48" States peaked in 1967. In 1968, production exceeded new discoveries for the first time. Reserve additions in the "lower 48" have never equalled annual consumption again even though production continued to rise until 1973. As Table 2 indicates, reported reserve additions were relatively high from 1954 to 1967, even though constant-dollar prices declined during the latter half of that period. Beginning in 1968, reserve additions dropped off at a remarkable rate, except for the 1970 discovery of the Alaskan North Slope fields. Production from the declining reserve base peaked in 1973 and has declined significantly since that time, although prices have risen by several hundred percent. The contrast between current perceptions of supply possibilities and those of the 1960s, despite the very large intervening price increase, makes it clear that estimates of the Nation's resource base have outweighed price effects in these assessments. A remarkable insensitivity to price is assumed in most current gas supply forecasts. Reasons for this pessimism are discussed more fully in Chapter II.

As shown in Table 2 (Chapter I), however, this drop off in resources is traceable in substantial part to large downward revisions of previously proven reserves, which give rise to suspicions about producer withholding. The section on allegations of withholding appearing in this chapter below contains further data on this subject.

Table 2. Natural Gas Production Compared to Discoveries, Revisions, and Extensions of Proven Gas Reserves, 1950-1975 (tcf.)

Year	Discoveries, Revisions, Extensions	Net Production
1950	12.0	6.9
1951	16.0	7.9
1952	14.3	8.6
1953	20.3	9.2
1954	9.5	9.4
1955	21.9	10.1
1956	24.7	10.8
1957	20.0	11.4
1958	18.9	11.4
1959	20.6	12.4
1960	13.9	13.0
1961	17.2	13.4
1962	19.5	13.6
1963	18.2	14.5
1964	20.3	15.3
1965	21.3	16.3
1966	20.2	17.5
1967	21.8	18.4
1968	13.7	19.4
1969	8.4	20.7
1970	37.2*	22.0
1971	9.8	22.1
1972	9.6	22.5
1973	6.8	22.6
1974	8.7	21.3
1975	10.5	19.7

* Includes Alaska

Source: AGA Gas Facts, Table 4

Experience Since 1973

Both actual and potential demand have continued to grow steadily despite an increasing production shortfall. A form of rationing has come into play through the inability of distribution systems and pipelines to add customers and later through formal curtailments of supplies to existing users. Table 3 shows the growth of actual curtailments of "firm" (i.e., contractually uninterruptible) service by interstate pipelines due to inadequate gas production. This method of allocating gas among would-be users clearly involves many inequities and should be replaced, if scarcity persists, with a more rational set of priorities. This matter is dealt with in greater detail in Chapter III.

With this increasingly painful shortfall, together with OPEC's 1973 oil price revolution, both interstate and intrastate gas prices began to rise. The large increases in FPC nationwide ceilings for interstate gas after 1973 have been chronicled above. In 1974, higher prices became noticeable in the average or "blend" prices paid by interstate pipelines. When the FPC raised rates in 1976 to $1.42 per mcf. plus adjustments, average prices paid by interstate pipelines rose at an accelerated rate.

Shortly after assuming office, President Carter proposed legislation -- the Emergency Natural Gas Act of 1977 -- which addressed the unexpectedly severe gas curtailments of the winter of 1976-1977. This Act, which was passed virtually unamended, contained two major provisions permitting: (i) Federal

Table 3. Net Curtailments of Contractually Firm Interstate Gas Deliveries, 1972-1977

Period	Billion Cubic Feet
9/72 - 8/73	1,031
4/73 - 3/74	1,191
9/73 - 8/74	1,362
4/74 - 3/75	2,013
9/74 - 8/75	2,418
9/75 - 8/76	2,976
4/76 - 3/77	3,338
9/76 - 8/77	3,771

Source: Federal Power Commission

allocation of gas among interstate pipelines until April 30, 1977, and (ii) purchases by interstate pipelines and industrial users from both producers and intrastate pipelines at prices which "the President determines to be appropriate." Under this law, the FPC authorized emergency sales of less than 0.1 tcf. Prices averaged $2.25 per mcf., except for one sale in excess of $3 per mcf.

Although no complete data on intrastate gas prices are available for periods before 1975, Table 4 shows the average prices paid by electric utilities in the gas-producing states. While these prices include some interstate gas as well as relatively small transport charges, they should be indicative of average intrastate wholesale prices. Their rise in the post-embargo era clearly implies an upward trend in intrastate prices for already flowing (old) gas.

To a large extent, however, intrastate gas markets have been protected from nationwide demand by regulation of interstate prices. Producing States -- notably Texas and Louisiana -- have found large supplies trapped for their use within their borders by prices there higher than in interstate commerce. These prices nonetheless are below those which would prevail in an unregulated national market. Thus, instate prices have been suppressed for a decade or more by the influence of price regulation in the interstate market. This is an often unnoticed, indirect benefit of FPC regulation to intrastate consumers. While such protection still exists, the impact of the 1976 booSt in FPC ceilings on prices in the main producing States is becoming observable. Table 5 shows the weighted averages of how

Table 4. Gas Prices Paid by Electric Utilities In Texas, Louisiana, Oklahoma & Kansas, Year End

Year	Price (¢/Mcf.)
1972	27
1973	34
1974	54
1975	83
1976	100

Source: FPC, Form 423

Table 5. Recent Intrastate Wellhead Gas Prices
(dollars per Mcf.)

	New Contracts			Renegotiated or Amended Contracts		
	High	Weighted Average	Low	High	Weighted Average	Low
1975 Average	2.07	1.29	.43	2.13	1.42	.26
January	2.00	1.12	.49	2.17	1.44	.21
February	1.95	1.20	.43	2.07	1.49	.76
March	2.07	1.04	.56	2.08	.76	.25
April	2.04	1.54	.20	1.91	1.67	.25
May	2.04	1.42	.44	2.08	1.46	.19
June	2.12	1.20	.47	2.32	1.58	.20
July	2.08	1.48	.31	2.35	1.52	.26
August	2.20	1.36	.30	2.17	1.06	.44
September	2.14	1.42	.40	2.12	1.53	.25
October	2.03	1.05	.38	2.11	1.51	.13
November	1.94	1.36	.46	2.04	1.74	.37
December	2.16	1.34	.75	2.09	1.32	.38
1976 Average	2.08	1.61	.49	2.19	1.64	.49
January	2.00	1.55	.14	2.21	1.84	.25
February	2.13	1.62	.15	2.21	1.70	.26
March	1.90	1.52	.71	2.21	1.62	.45
April	2.16	1.73	.51	2.09	1.22	.18
May	2.01	1.39	.15	2.34	1.83	.16
June	2.04	1.67	.29	2.18	1.71	.49
July	2.17	1.27	.49	2.21	1.15	.20
August	2.03	1.55	.40	2.29	1.69	.80
September	1.97	1.72	.93	2.28	1.95	.97
October	2.12	1.79	.47	2.16	1.58	.48
November	2.09	1.65	1.16	1.99	1.63	.50
December	2.33	1.85	.46	2.17	1.76	1.14
1977 Average						
January	2.35	1.81	.19	2.31	1.85	.82
February	1.98	1.66	.42	2.31	1.76	.45
March	2.39	1.91	.44	2.35	1.71	.34

Source: FPC, Bureau of Natural Gas, "Intrastate Gas Prices of FPC Jurisdictional Natural Gas Companies Selling More than One Million Mcf. Per Year in Interstate Commerce," FPC Form 45, 1975-1976.

prices in new and renegotiated intrastate contracts have increased since the FPC began collecting data.

Trends in Drilling

Table 6 delineates the trend in drilling activity during the past quarter century. A highlight is the upsurge in gas wells drilled since 1974. Moreover, 1976 was a record year for gas well completions.

One can speculate on the reasons why the number of gas wells increased so rapidly between 1972 and 1976. Two reasons could be (i) high profitability of developmental drilling in old fields to convert "old" gas to "new" gas under the FPC's definitions, and (ii) high profitability of new gas sales to the intrastate market at the relatively high new contract prices which prevailed during this period.

The first theory gains credibility from the fact that, while drilling effort increased sharply between 1972 and 1976, the number of dry holes did not increase proportionately. This would imply that producers drilling new wells did so in areas where there was a much higher probability of finding gas -- i.e., in old fields. Table 6 shows that drilling activity conformed to this pattern.

Data on the sources of reserve additions also support the theory that much recent drilling has taken place in and around old fields. Table 7 indicates that most new

TABLE 6. DRILLING ACTIVITY IN THE UNITED STATES

Year	Total Well Completions					Total Ft. Drilled (Mil.Ft.)
	Oil	Gas	Dry	Service	Total	
1957	28,612	4,626	20,893	1,409	55,024	233.1
1958	24,578	4,803	19,043	1,615	50,039	198.2
1959	25,800	5,029	19,265	1,670	51,764	209.2
1960	21,186	5,258	17,574	2,733	46,751	190.7
1961	21,101	5,664	17,106	3,091	46,962	192.1
1962	21,249	5,848	16.682	2,400	46,179	198.6
1963	20,288	4,751	16,347	2,267	43,653	184.4
1964	20,620	4,855	17,488	2,273	45,236	189.9
1965	18.761	4,724	16,025	1,922	41,432	181.5
1966	16,780	4,377	15,227	1,497	37,881	166.0
1967	15,329	3,659	13,246	1,584	33,818	144.7
1968	14,331	3,456	12,812	2,315	32,914	149.3
1969	14,368	4,083	13,736	1,866	34,053	160.9
1970	13,020	3,840	11,260	1,347	29,467	142.4
1971	11,858	3,830	10,163	1,449	27,300	128.3
1972	11,306	4,928	11,057	1,464	28,755	138.4
1973	9,902	6,385	10,305	1,010	27,602	138.9
1974	12,784	7,240	11,674	1,195	32,893	153.8
1975	16,408	7,580	13,247	1,862	39,097	178.5
1976	16,996	9,045	13,690	1,690	41,421	185.2

Source: Independent Petroleum Association of America.

TABLE 7

ANNUAL ESTIMATES OF PROVED NATURAL GAS RESERVES IN THE UNITED STATES, 1965 THROUGH 1976
TOTAL ALL TYPES

(Millions of Cubic Feet - 14.73 psia, at 60° F.)

	Changes in Reserves during Year								
Year	Revisions	Extensions	New Field Discoveries	New Reservoir Discoveries in Old Fields	Total of Discoveries, Revisions and Extensions	Net Change in Underground Storage	Production[b]	Proved Reserves at End of Year	Net Change From Previous Year
1965	14,775,570 a		6,543,709 a		21,319,279	150,483	16,252,293	286,468,923	5,217,469
1966	4,937,962	9,224,745	2,947,329	3,110,396	20,220,432	134,523	17,491,073	289,332,805	2,863,882
1967	6,570,578	9,538,584	3,170,520	2,524,651	21,804,333	151,403	18,380,838	292,907,703	3,574,898
1968	3,016,146	7,758,821	1,376,429	1,545,612	13,697,008	118,568 d	19,373,427 d	287,349,852	(5,557,851)
1969	(1,238,261)	5,800,489	1,769,557	2,043,219	8,375,004	107,169	20,723,190	275,108,835	(12,241,017)
1970	(99,721)	6,158,168	27,770,223	3,367,689	37,196,359	402,018	21,960,804	290,746,408	15,637,573
1971	(1,227,400)	6,374,706	1,317,574	3,360,541	9,825,421	310,301	22,076,512	278,805,618	(11,940,790)
1972	(1,077,791)	6,153,683	1,462,539	3,096,132	9,634,563	156,563	22,511,898	266,084,846	(12,720,772)
1973	(3,474,756)	6,177,286	2,152,151	1,970,368	6,825,049	(354,282) c	22,605,406	249,950,207	(16,134,639)
1974	(1,333,285)	5,847,251	2,013,745	2,151,473	8,679,184	(178,424) c	21,318,470	237,132,497	(12,817,710)
1975	383,449	6,027,433	2,423,382	1,649,424	10,483,688	302,561 c	19,718,570	228,200,176	(8,932,321)
1976	(1,197,119)	5,337,707	1,421,013	1,993,867	7,555,468	(187,550)	19,542,020	216,026,074	(12,174,102)

a - Separation of revisions from extensions of new field discoveries from new reservoir discoveries in old fields not available prior to 1966.
b - Preliminary net production.
c - See footnote e, Table I.
d - This value has been changed to correct a numerical error made in Volume 23.
( ) Denotes negative volume.

Source: American Petroleum Institute. Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1976.

reserves have normally come from revisions and extensions of old fields.

The large price increases for both interstate and intrastate gas, nonetheless, undoubtedly have raised the incentive to find truly new gas reserves as well as to convert old gas to new. The future productivity of these drilling efforts, however, remains to be seen. As Chapter II will show, serious doubts have been raised about the volumes of gas remaining to be discovered within United States territory.

Allegations of Withholding

There have been numerous allegations involving specific situations in which proven reserves of gas on the Outer Continental Shelf purportedly have been withheld from sale in hopes of higher prices in the future. These allegations involve a refusal to produce out of existing and known reserves dedicated to interstate commerce, not merely under-reporting or failing to report new reserves, which is often considered withholding as well.

Under-reporting or not reporting reserves is the hardest charge to substantiate definitively. Substantiation of the existence of sizable hidden reserves would require examination of vast amounts of geological data and the expertise to evaluate it. Moreover, substantial geophysical testing would be called for to check the data's validity. The FPC has attempted to validate the reserve base, but its study is the subject of some controversy. The FPC

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examined only a sample of new and old fields. It found reserves in the sampled fields nearly equal to those that had been reported. However, critics express concern about the sample's validity, and contend that new fields, where the most under-reporting is claimed to have occurred, were insufficiently investigated.

One of the more important sources of suspicion regarding withholding is the downward revision of old fields' reserves. These reserves are largely dedicated to the interstate market. Table 8 contains data on selected fields and producing areas. Dates of discovery show that most of these fields are old and must have well-known geology. Typically, old fields have low production rates as well, yet large declines in reserves were recorded during short periods of the past decade. It should be noted that the revisions are net figures that take account of reserves added as well as downward revisions. The downward revisions in pre-existing reserves, therefore, are substantially larger than the net figures show. Thus, for example, a decline of 2tcf. in Texas District 3 shown in Table 8 appears to indicate an extraordinary drop in the reserve data.

In any event, as Chapter II will indicate, it is clear that incentives to withhold production of interstate gas have been quite strong since the early 1970s. It is very difficult to believe that producers have not responded to this incentive, at least in the many cases where no legal obligation prevented their doing so.

Table 8. American Gas Association Estimates of Ultimate Recovery of Natural Gas, Billion Cubic Feet (BCF), Selected Years of Reservoir Discoveries and Estimates

	Years			Estimates (BCF)	
A. Non-Associated	Discovery	From	Through	From	To
Texas					
District 1	1953	1970	1974	390.4	206.0
District 2	1963	1967	1970	430.2	187.1
District 3	1935	1970	1973	5,809.5	3,828.3
District 4	1940	1970	1975	1,504.4	854.5
District 7B	1929	1966	1967	74.0	7.4
District 7C	1965	1969	1971	694.1	365.8
District 9	1950	1968	1969	2,442.7	2,204.7
Louisiana					
North	1927	1966	1967	647.1	.4
South	1959	1969	1973	5,391.4	593.3
B. Associated-Dissolved					
Texas					
District 3	1929	1966	1974	543.7	82.0
District 4	1939	1970	1975	1,714.4	1,147.6
District 5	1933	1969	1970	192.0	142.0
District 6	1930	1967	1974	1,958.1	1,414.5
District 8	1949	1966	1968	1,509.1	76.5
Louisiana					
South	1937	1969	1975	2,939.3	1,925.3

Source: Tabulations prepared by Joseph Lerner from Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas . . ., American Petroleum Institute & American Gas Association, various editions.

Future Gas Prices Under Existing Regulations

Interstate prices, now averaging nearly 60 cents per mcf., will converge in time on the $1.42 rate, plus adjustments, applicable for new gas. How long this convergence will take is hard to estimate. Between January 1973 and August 1976, average interstate prices rose by 133 percent from 24 cents per mcf. to 56 cents per mcf. During the 1-1/2 years when the 42 to 52-cent price ceiling prevailed, producers had found ways to increase average prices, including adjustments, up to the then current new gas ceilings. With constant readjustments of old gas prices, which the FPC has provided, substantial price rises already are programmed into the system.

It would appear, therefore, that average interstate gas prices will converge toward $1.50 per mcf. within several years even without any changes in present regulatory procedures and without any new increases in the FPC's national ceilings. Such price rises will cost gas users over $10 billion per year for today's volume of gas deliveries.

1/ 15 U.S.C. 717.

2/ 347 U.S.C. 672, Phillips Petroleum Co. v. Wisconsin (1954).

3/ Clark A. Hawkins, The Field Price Regulation of Natural Gas. p. 23.

4/ Robert B. Helms, Natural Gas Regulation: An Evaluation of F.P.C. Price Controls. p. 19.

5/ Hawkins, op. cit., pp. 77-78.

6/ An mcf. (1000 cubic feet) of gas contains an average of about 1,030,000 Btus.

II. A REALISTIC VIEW OF POTENTIAL NATURAL GAS SUPPLIES

The rate at which natural gas reserve additions can become available in the future is critically dependent on the size of the undiscovered but economically recoverable natural gas resource base. The prevailing opinion in the past has been that there is a vast amount of undiscovered natural gas remaining to be developed in the lower 48 States and the adjacent offshore waters. It has also been taken for granted that this large untapped resource could be developed readily by increasing the industry's exploration incentive. The belief in a vast undiscovered resource base has been based largely on estimates published over the years by both the United States Geological Survey (USGS) and by the Potential Gas Committee (PGC), an industry-sponsored group. In 1974, the USGS estimated that the lower 48 States' undiscovered natural gas resource base fell within a range of 725 to 1,450 trillion cubic feet(tcf.) with a 90 percent probability. Adding estimates for Alaska, the range increased to between 990 to 2000 tcf. The PGC estimate for undiscovered gas in the lower 48 States is 568 tcf.

The accuracy of these estimates is being called into question increasingly, however, not only by some of the major oil companies' geologists but by the National Academy of Sciences and the USGS itself. Just one year after issuing the above forecasts of potential reserves, the USGS revised its estimates radically downward, to 286 to 529 tcf. for the lower 48 States and 29 to 132 tcf. for Alaska, raising the total estimated U.S. reserve base to the 322 to 655 tcf. range. 7/ These estimates are 60 to 70 percent smaller than the previous ones, despite the very large price increases that had taken place in the meantime. They reflect the pessimism with which the Nation's reserve base has come to be viewed in recent years. One must bear in mind, of course, that all such figures are extremely speculative.

Estimates of Production Possibilities

With proven nationwide reserves now at 220 tcf., including Alaska's 26 tcf. of presently inaccessible gas, prospects for major increases in output during the remainder of this decade do not appear good. At present production rates, in fact, the upper limit of the total resource base estimates for the "lower 48" (including still undiscovered resources) will support only 26 more years of production, assuming that all of these reserves indeed can be found. Alaskan reserves could extend this horizon by up to 6-1/2 years. The lower limit of the estimated resource base would sustain current production for only 15 years. In fact, these reserves will not be exhausted within such a short time, but if the resource-base estimates are valid, they augur substantial output declines in coming years.

What production levels can realistically be expected from the lower 48 States? The recent FPC study, 8/ provides some interesting insights. Figure 1 shows its estimates of production capabilities under various assumptions about reserve additions. Assumed reserve additions of 14.7 tcf. per year equal the 1960-1975 average for the 48 States, while 9.5 tcf. per year is the corresponding figure for 1968-75.

Figure 1

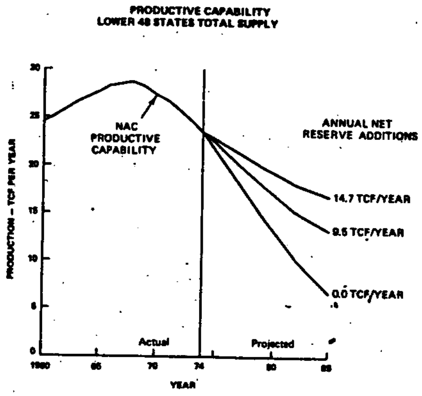
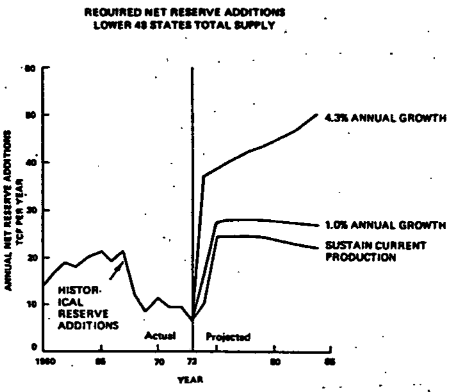


Figure 2



Source: F.P.C., <u>A Realistic View of U.S. Natural Gas Supply</u>.

Figure 2 shows the reserve additions needed to support various production growth rates. The 1960-1973 growth rate was 4.3 percent per year, one that would require implausibly large volumes of new reserves to be sustained in the future. Figures 1 and 2 show graphically the need for increased reserve additions if present production levels are to be maintained. They also demonstrate that sharp production declines can be expected in the near future if larger reserve additions are not attained.

Since 1970, numerous forecasts of future consumption and production levels have been made, some predicting output rates in excess of 50 tcf. per year within this century. Table 9 contains a summary of many of these forecasts in chronological order. Looking down the column for 1985, the trend over time toward diminishing expected production and consumption rates is clear.

The econometric supply projections, appear to result in forecasts that are quite out of line with current thinking. Typical of these efforts is the MacAvoy-Pindyck 9/ paper, published in 1975. Their findings are shown in Table 10, which is reproduced from that study. Viewed in 1977, these forecasts of 33 tcf. of gas production in 1980 at new gas prices of $1.00 per mcf. are not in accord with current perceptions of reality. This divergence implies that the parameters of production possibilities in the gas industry have changed fundamentally since the 1950 to 1970 period, probably due to the recent realization that the U.S. resource base already has been substantially exploited.

Unless recently revised perceptions are faulty, therefore, U.S. output of natural gas will continue to decline somewhat even at

TABLE 9.

FORECASTS OF U.S. NATURAL GAS CONSUMPTION
(trillion of B.t.u.'s)

Source	1970	1975	1980	1985	1990	2000
SRI 1970		23,848	29,871			
WEM, 1970			27,239		35,005	41,693
EBAS, 1970	21,900	26,000	30,400	35,000		
RFF 1971			27,329		35,005	47,097
BOM, 1971						(2)35,914 (2)57,482
NPC, 1971	23,338	22,420	22,480	22,180		
FRC, 1971	(1)26,143	(1) 33,906	(1)38,516	(1)43,625	(1)50,115	
RRFF, 1971		23,800	27,500			
PIRF, 1971		26,800	30,600	34,400		
CMB, 1972				27,161		
CMB, 1972						
DOI, 1972		25,220	26,980	28,390		33,980
FPC, 1973		25,009	24,331	25,680	28,870	33,908
FORD, 1974			(3)28,000			(3) 32,000
AEC, 1974			(4)29,600			(4) 30,500
CEQ, 1974						(5) 20,000
LLL, 1974			(6)27,550	(6)29,900		
FEA, 1974			(7)23,140	(7)24,775		
H & J 1975			26,800	28,022	28,612	28,639
ERDA, 1975			(8)24,000			(8) 15,400
FPC, 1975			25,490	26,110	26,006	
CRS, 1975				19,000		
NEO, 1976				22,300		
LEVY, 1976				17,900		
NEO, 1977 (Draft)				16,600		

(1) The forecasts are estimated of energy requirements as defined by the Future Requirements Committee.
(2) Excluded from graphs of natural gas forecasts given on following p.5
(3) Projection offered as scenario possibilities and not predictions; based on imports cut to half present levels, and imports at 3,000,000 barrels per day for 1985-2000.
(4) Assumes continuation of past relationship between energy consumption and GNP and further increase in the importance of electricity as a secondary energy source.
(5) Target projection associated with a program of energy conservation and environmental protection.
(6) Medium scenario projection
(7) Base case projection assuming current policies will prevail without energy conservation; $11/bdl imported oil.
(8) No new initiatives scenario case.

KEY TO TABLE 9

SRI-1970: Requirements for Southern Louisiana Natural Gas through 1980, Federal Power Commission Area Rate Proceedings. Exhibit in FPC Docket No. AR69-1, Standford Research Institute, April 1970.

EW-1970: 21st Annual Electrical Industry Forecast, Electrical World, September 15, 1970.

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KEY TO TABLE 9 (con't)

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LEVY-1977: An Assessment of U.S. Energy Policy, September, 1976.

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TABLE 10 - MacAVOY/PINDYCK ECONOMETRIC SIMULATIONS OF PHASED DEREGULATION OF NATURAL GAS

ECONOMETRIC SIMULATIONS OF PHASED DEREGULATION OF NATURAL GAS

Year	New Discoveries (Tcf)	Total Additions to Reserves (Tcf)	Total Reserves (Tcf)	Supply of Production (Tcf)	Demands for Production (Tcf)	Excess Demand for Production (Tcf)	New Contract Field Price (¢/Mcf)	Average Wholesale Price (¢/Mcf)
1972	4.7	8.8	233.4	23.3	23.5	.2	31.7	39.9
1973	9.9	17.0	227.8	23.6	24.3	.7	34.7	41.4
1974	10.0	18.4	222.9	24.3	26.3	2.0	39.7	44.3
1975	16.3	24.8	222.3	26.4	28.7	2.3	64.7	52.7
1976	21.4	30.5	226.1	27.6	30.4	2.8	71.7	59.6
1977	25.4	35.3	233.9	28.6	31.9	3.3	78.8	68.3
1978	30.0	41.1	245.8	30.2	32.9	2.7	85.9	73.7
1979	31.5	43.9	258.6	32.1	33.7	1.6	93.1	81.1
1980	33.0	45.6	271.2	34.1	34.2	0.1	100.3	88.3

Source: Table 8, <u>Price Controls and The Natural Gas Shortage</u>, American Enterprise Institute.

today's higher prices. This would be equally true at the price levels proposed by the Carter Administration and approved recently by the House of Representatives, or those resulting from lifting price controls. In fact, production is expected to decline -- or at best to remain at present levels -- at virtually any price level.

Energy Prices and Production Economics

To understand the role of prices in determining future energy supply and the effects of sharp price changes on the industry, one must be familiar with the economics of mineral production. To judge by the current public debate, there is a need for education on these subjects. The following discussion will outline the economics of production, assuming initially that cost-price relationships are constant. Then it will consider the effect of a sharp increase in prices such as that which occurred in 1973. Finally, it will deal with the effect on production of an expectation of large future price increases.

Production Economics With Constant Prices and Input Costs

Production of any mineral requires a sequence of decisions to proceed with successive exploration and development steps, each of which involves increased financial commitment. First, a geologically attractive property must be selected. Geophysical work must be done, and mineral rights must be leased. Typically, exploratory drilling will then commence. This investment is more or less risky depending on whether the property is in or adjacent to an area with known hydrocarbon deposits, or a truly wildcat effort distant from any other previous discoveries of oil or gas. Clearly the readiness to engage in exploratory drilling, particularly wildcatting, depends on the prospect that a find will be profitable to develop based on the price-cost relationships prevailing in the industry.

After an oil or gas deposit is located, the decision whether or not to proceed with development drilling and full-scale production depends primarily on the cost of the development drilling versus the volume of output expected over the lifetime of the well, taking cognizance of the distribution of output revenues over time. If the cost of development plus required profit margin is lower than or equal to the present value of revenues from the sale of output, then development of the deposit is attractive. The final decision to develop a find does <u>not</u> depend on the cost of initial exploration and wildcat drilling, because these costs are irretrievably "sunk" at the time of this decision.

Recovery rates from different wells can vary greatly. Thus, for instance, an offshore well that is expensive to drill does not necessarily mean high-cost oil or gas, because prolific offshore wells may produce at lower costs per barrel or mcf. than shallow onshore wells that are cheap to drill but have low output rates. Because of their high productivity, some expensive wells in the North Sea and in Alaska, for example, are expected to produce oil at wellhead costs of $2 per barrel or less.

At any given price, some finds will be attractive to produce while others are barely economic and some will be unprofitable to develop and will be left in the ground. At low prices the incentive to explore is low, and the profit requirement will mean that only relatively large deposits are produced. At prices in today's range, however, only wells with a very high ratio of cost to recoverable reserve (i.e., deposits with very high unit costs) will not be produced. At any price level, however, the prospective productivity of high-cost offshore wells must be substantially greater than that of onshore wells to justify development, and the expected recoverable reserves of a deep deposit must exceed those of one nearer to the surface to justify the disproportionately higher cost of deeper drilling. In the case of natural gas, moreover, the costs of delivering the gas to the nearest pipeline or gathering system also have a bearing on how much expense can be incurred to bring it to the surface.

The estimated profitability of potential output, taking account of drilling costs, well productivity, gathering, and other costs, determines the value of the mineral rights that the prospective producer must acquire before starting to drill. To the extent that these costs are accurately known, any profits in excess of normal returns to an entrepreneur's labor and capital will tend to be largely preempted by the landowner. Often, of course, the entrepreneur and the landowner are the same person (or organization).

The Effects of Sharp Price Changes

Oil and gas drilling in the United States declined throughout the 1960s because the output prices of these fuels declined relative to the costs of drilling, squeezing the profit out of more and more prospective finds. The threat of imported oil at much lower prices was held at bay only by government restrictions on imports. Relatively few new drilling rigs were built; employment in domestic oil and gas fields declined; and the value of oil and gas drilling rights languished.

In early 1973, world oil prices rose to and exceeded U.S. levels. In October, the Arab oil embargo was declared, and, by December both Arab and non-Arab OPEC countries raised oil prices by some 250 percent. Prices for the output of new domestic oil wells and for natural gas in intrastate commerce were permitted to rise on the coattails of the cartel, while the controlled prices for already flowing oil and interstate gas were raised substantially during the following year. Certain additional categories of oil were released from controls and permitted to gravitate toward the world level.

This revolutionary increase in prices precipitated a boom in drilling by vastly increasing the profitability of finding oil or gas. Oil and gas production costs also rose rapidly, however, as producers bid eagerly for limited mineral rights and supplies of experienced labor and equipment, such as drilling rigs and pipe. Because windfall profits were neither suppressed nor effectively taxed away, the process of bidding for inputs tended to absorb them. Much of the excess profit remaining after payment of the variable costs of production were bid into the value of mineral rights. Pre-existing owners of mineral rights and other oilfield inputs enjoyed sudden, large gains. Among the major owners of mineral rights is the Federal Government with its jurisdiction over public lands and the Outer Continental Shelf.

This process of inflation did not stop with the oil (and gas) itself. Employees and suppliers of inputs not employed directly in drilling operations also commanded a share of the windfalls. It has been estimated that the variable costs of all domestic operations of ten major oil companies rose by 25 to 35 percent in one year from 1973 to 1974, not including the higher cost of crude oil purchased from others and the rise in oilfield investments. 10/ In other words, the costs of equipment and supplies purchased from others and labor costs in all phases of the business rose by proportions in this range. Nor was the OPEC-induced inflation confined to the oil and gas industry. It spilled over to coal, uranium and electric power production, affecting all firms providing inputs to these industries as well. The rising costs for drilling in the United States stemming from cartelization of world oil prices outstripped yesteryear's regulated prices of interstate natural gas for most producing fields.

Now four years after the energy price revolution, drilling activity continues to rise. Capacity to produce drill pipe, bits and rigs, as well as the supply of experienced oilfield personnel, is expanding, and the industry's cost structure has reached something approaching a new equilibrium. Moreover, certain elements in this cost structure -- particularly the values of mineral rights -- are flexible in the downward as well as upward direction. If the expected profitability of production should fall, due either to rises in other costs or to limitations on expected output prices (e.g., through imposition of a price ceiling on natural gas), it is not the incentive for future productive effort but rather the value of mineral rights which will absorb much of the decline. Such an adjustment in the values of mineral rights (basically a rent payment) will have minimal effect on incentive to develop and produce from most properties. Only in the case of properties that were <u>barely</u> profitable before the change in price-cost relationships occurred could a decision to produce from them be reversed. In these few cases, profitability would be supressed, and such properties probably would be withdrawn from exploitation.

The large lease bonuses collected by the Federal Government indicate the high potential profitability of producing oil and gas at today's prices even in virgin territories in deep water. To the extent that the values of these mineral rights remains substantial, any limitation or even a rollback of oil or gas prices would have the effect mainly of limiting the increase in those values and not of limiting exploration and production on government lands.

Another important influence of the value of mineral rights, of course, is the Government's policy regarding the rate at which drilling rights on public lands are leased. An increase in the rate of leasing, other things equal, would tend to reduce the prices of all oil and gas rights. Simultaneously, however, it would tend to create scarcity and rising prices for other oilfield inputs. Such a policy would reduce long-term Treasury revenues from public lands and boost scarcity rents to private oilfield suppliers. The inconsistency between the Government's interest in maximizing revenues from mineral leases and the Nation's interest in enhancing domestic energy output is a matter that must be resolved.

<u>Effects on Production of Expected Price Increases</u>

If large increases in the future prices of oil or gas are anticipated, which continues to be the case, a producer with access to potential reserves must decide whether to produce for sale at current prices or to postpone production until prices rise. The decision will be based largely on the rate of return which may be earned by holding the reserves as an investment compared with that of alternatives in which the revenues from selling them can be invested. If the rate of energy price increase is higher than the return on alternative investments -- e.g., the prevailing rate of interest -- a producer will do better by holding his reserves. In this situation, energy in the ground is a better investment than money in the bank. This certainly has been the case in recent years with natural gas destined for the interstate market (which includes all gas on offshore Federal leases) and to some extent to other gas and oil.

Consider a producer who could have delivered natural gas for interstate commerce in 1970. A typical new gas price for that year was about 20 cents per mcf. If the producer delayed selling those reserves until 1976, when the national rate of $1.42 became effective, his gas had increased in value by 470 percent, or nearly 40 percent per year. Had the gas been sold in 1970, the producer would have been extremely unlikely to find an alternative investment with such a rate of return.

A strong incentive has existed to withhold gas for this reason. Anticipation of deregulation or rapid increases in national price ceilings continues to encourage such behavior. These expectations will hamper gas production so long as there is no clear-cut policy that gas price increases will be limited to moderate amounts. An unambiguous statement or legislative mandate establishing such a policy would greatly diminish the withholding incentive. Annual price adjustments to offset inflation or for other reasons will not make withholding attractive so long as the appreciation of gas in the ground is no faster than the rate of return on alternative investments. Such a clarification of pricing policy must be a primary objective of Congress as it addresses natural gas regulatory legislation.

Policy Implications of the Supply Situation

Resource considerations should have a central role in shaping national gas policy. If the reserve base is indeed relatively small, and if only limited reserve additions can be anticipated, policies that limit consumption are in order. On the other hand, if perverse producer behavior under current and past FPC regulatory practice has led to reserve and production withholding, and if the past 10 years of reserve additions are substantially understated, perhaps current production levels can be maintained or even enlarged during the next 25 years.

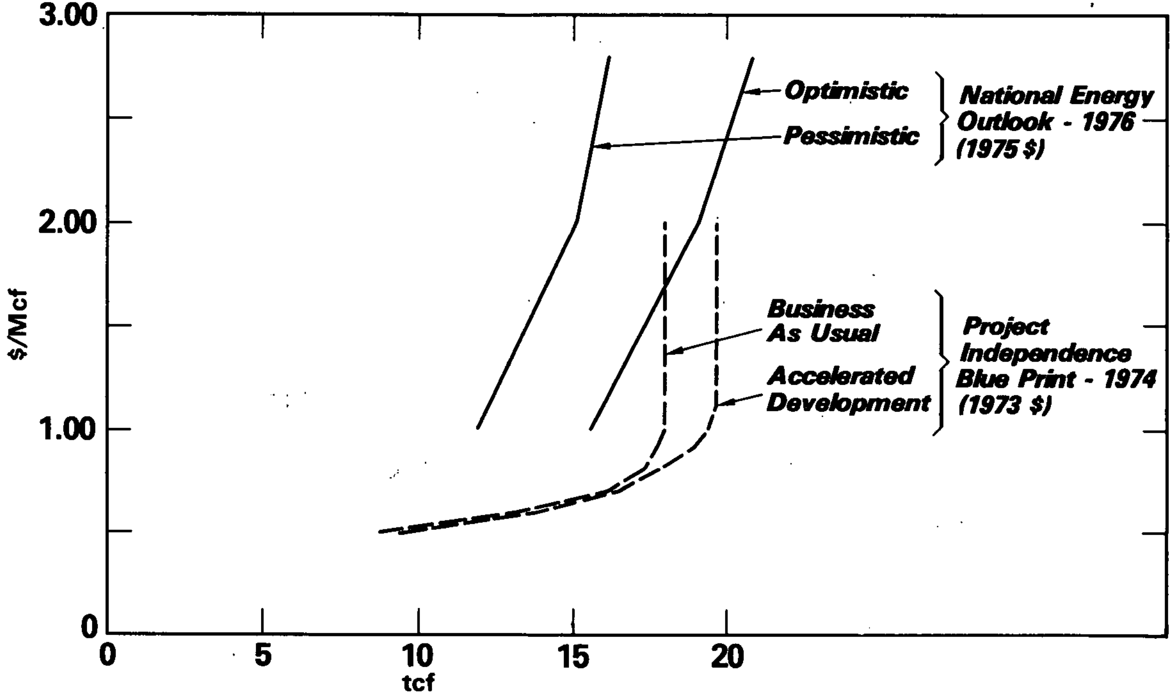
It is our judgment that increases in production above the present rate of less than 20 tcf. per year are unlikely, even under optimistic assumptions. The obvious implication of such a conclusion is that gas consumption should be discouraged generally, boiler fuel uses should be terminated, and the released supplies should be allocated to high-priority users. There are two basic approaches to limiting consumption and allocating supplies. These are (i) administrative measures controlling end uses and (ii) market-determined allocation using the price mechansim. Both of these will be discussed in later chapters. It would not appear advisable to rely exclusively on either. Instead, a combination is needed, as explained below.

In the face of rigid constraints on domestic supply and the very limited availability of natural gas imports, prices in the absence of controls could go to extremely high levels. High prices for domestic production can be justified, however, only to the extent that they serve U.S. national purposes such as reduced import dependency. The extent to which price levels beyond today's will increase production is questionable. The existing system of utility-type regulation for interstate gas, however, never was designed to cope with a situation of monopoly pricing in the energy market, such as that imposed by OPEC, and it must be replaced with a system that takes cognizance of the new circumstances.

Chart 1 illustrates why high, cartel-induced energy prices cannot be expected to bring forth substantial amounts of new gas supply. The chart is based on two Federal Energy Administration (FEA) analyses of supply. The first -- from the 1974 Project Independence Blueprint (PIB) -- shows clearly how inelastic 1985 supply is to prices above the $1.00 per mcf. (measured in 1973 dollars) level. A second analysis -- contailed in the 1976 National Energy Outlook (NEO) -- shows a supply curve of similar shape. However, the NEO curve has moved upward due in part to inflation (NEO is measured in more inflated 1975 dollars), and in part to the fact that gas is simply becoming harder to find. The

Chart 1

Long Term Effect of Price on Natural Gas Production in 1985 - Non Associated Gas



result is clear: the same amount of gas at higher prices.

NEO shows not only lower price sensitivity than PIB in the $1.00 to $2.00 range, but greater elasticity above $2.00. Nevertheless, there seems to be a well defined point with both PIB and NEO where the supply response is reduced. It would seem that the relevant point today would be somewhere in the $1.75 to $2.25 per mcf. range. However, even with NEO, elasticities are clearly less than 1. This means that every 1 percent price increase yields a 1985 supply increment substantially smaller than 1 percent.

The question is raised of how much should be paid -- in terms of higher prices for all gas -- for incremental supplies which are forthcoming in continuously diminishing volumes. If, for example, using the NEO optimistic scenario, 19 tcf. of associated gas can be produced at $2.00 per mcf. in 1985. At $2.50, 20 tcf. would be forthcoming. But the 19 tcf. would cost $38 billion, and the 20 tcf. produced under this scenario would have cost $50 billion. This means that the incremental 1 tcf. of output has a marginal cost of $12 billion, or a rather expensive $12.00 per mcf.

The great rise in oil prices in 1973 pulled the prices of uncontrolled intrastate natural gas up to similar levels. Controls on interstate natural gas prices will not be tenable without their extension to intrastate markets. If gas prices are not effectively controlled, moreover, they will tend to leapfrog the level of controlled oil prices and may rise to levels substantially above the equivalent of world oil prices set by the OPEC cartel. Such leapfrogging, if it occurred, would undermine the system of oil price controls by again driving up input costs and distorting the production incentives between oil and gas. It is strongly advisable, therefore, that natural gas prices be controlled at a level consistent with the regulated prices of oil, as proposed by the President and approved by the House of Representatives.

In the debate on energy prices and taxes, it should be recognized by all that for U.S. companies the profitability of new energy production in the United States remains higher and more secure than in virtually any other part of the world. Although the prices of new output are held slightly below world price levels, the taxes on production income are much lower than in other countries. In the OPEC nations, for instance, the producing companies now receive only a small service fee for lifting the oil. In the North Sea, the governments involved have taken controlling interests in the oil ventures. Thus, the incentives to find oil and gas in the United States remain among the strongest in the world, because it is only here that a person can produce and sell a barrel of oil or an mcf. of gas and keep most of the proceeds.

7/ U.S. Geological Survey, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, Circular 725. It should be noted that the total low and high values were not obtained by arithmetic summation but rather by statistical methods.

8/ A Realistic View of U.S. Natural Gas Supply, Federal Power Commission, Staff Report, December 1974.

9/ MacAvoy, Paul W., and Robert S. Pindyck, Price Controls and the Natural Gas Shortage, American Enterprise Institute, 1975.

10/ "Oil Profits, Prices, and Capital Requirements," Paper No. 1 of Volume 2 of a compendium, Achieving the Goals of the Employment Act of 1946 -- Thirtieth Anniversary Review, Joint Economic Committee, September, 1975.

III. CURBING THE DEMAND FOR GAS

Price Elasticities

At prices equal to or less than oil fuel equivalents, the potential demand for gas is extremely large and hard to measure, because actual consumption has been depressed by scarcity. Estimating the demand, therefore, elasticities for gas is a complex problem which is nevertheless central to determining the efficacy of price as a conservation tool. Numerous attempts have been made over the years to estimate both short and longer-term price elasticities. Lester Taylor 11/ has compiled a useful historical summary of thought in this area. For the most part these estimates suggest relatively high elasticities for the long run (i.e., with absolute value greater than 1). This implies that price would be a relatively effective conservation tool only after several years had passed. In general, Table 11 shows that a one-percent price increase results in the long run in more than a one-percent demand reduction. These elasticities assume fixed prices for oil and other substitute fuels. If these prices rise also, the elasticity of gas demand would be smaller.

The most current and extensive work on demand elasticity is being done by the Federal Energy Administration (FEA), and that work is worthy of some description. Based on a dynamic model which focuses on year-to-year shifts, it traces the transition in consumption patterns as gas prices rise relatively slowly toward equivalency with oil. Changes in the stock of gas-burning equipment are accounted for as a function of time, as are the inter-fuel substitutions

Table 11. Price Elasticities of Natural Gas Demand
Summary of Econometric Estimates

Type of Demand	Price Elasticity Short-Run	Long-Run
RESIDENTIAL		
Verhulst (1950)	-	-3.00
Felton (1965)	-	-1.72
Houthakker & Taylor (1970)	0	0
Anderson (1973)	-	-1.73
Randall, Ives & Ryan (1974)	-	-1.12
FEA (1976)	-0.16	-1.26
COMMERCIAL		
Felton (1965)	---	-1.45
FEA (1976)	-0.38	large
RESIDENTIAL-COMMERCIAL		
Balestra (1967)	small	-0.70
Berndt & Watkins (1975)	-0.20	-0.90
INDUSTRIAL		
Vermetten & Plantinga (1953)	-	-2.11
Felton (1965)	-	-1.50
Anderson (1971)	-	-1.98
MacAvoy & Noll (1973)	-	-1.78
FEA (1976)	-0.17	-0.58
COMMERCIAL-INDUSTRIAL		
Randall, Ives & Ryan (1974)	-	-3.85
TOTAL RETAIL SALES	-	-1.91

Source: Lester Taylor, "The Demand for Energy, A Survey of Price & Income Elasticities."

facilitated by equipment changes. The model takes account of the fact that gas users' reaction times are a function of the procurement cycle for new equipment using different fuels and for energy-saving devices and more efficient facilities. FEA's exercise considers these dynamics, and Table 12 displays the resulting elasticities over time.

The main drawback of immediate large price increases is apparent from Table 11 and Table 12. It can be seen from most elasticity estimates that price-induced conservation is relatively ineffective in the short run. As time progresses and users can switch to other fuels or carry out conservation efforts, price effects on demand become more pronounced. Immediate price increases (as with deregulation would have to be paid during the early years, when few energy savings result, as well as in later years when conservation benefits are a more substantial offset to costs.

There seems to be a fundamental conflict between the current FEA estimates and the earlier studies summarized by Taylor, inasmuch as FEA sees low elasticities (absolute values less than 1), and especially low elasticities for industry. This can be explained in part by recognizing that, at burner-tip prices below those of oil fuels (a situation which has existed in the past and will continue to exist for several years), gas savings come only from conservation through more efficient use, installation of energy-saving devices, and such measures, but not from fuel switching.

Table 12. Price Elasticities of Natural Gas Demand by Consuming Sector, 1977 to 1985

Year	Commercial	Residential	Industrial	Total
1977	- .403	- .332	- .213	- .268
1978	- .490	- .388	- .264	- .331
1979	- .559	- .428	- .297	- .358
1980	- .614	- .458	- .318	- .382
1981	- .659	- .481	- .333	- .399
1982	- .696	- .499	- .343	- .411
1983	- .726	- .514	- .350	- .420
1984	- .751	- .526	- .356	- .426
1985	- .773	- .535	- .360	- .431

Source: Federal Energy Administration

Conservation Through Regulation

A certain amount of conservation occurs through the curtailment plan presently implemented by the FPC. This plan, which really was designed for small, transitory supply shortfalls, essentially curtails large volume users first and involves smaller users as shortfalls become more serious. Its underlying logic is that larger users can switch to other fuels more easily than smaller consumers during shortage periods. In fact, however, priorities are based on volume of usage rather than on ability to use alternative fuels. "Quality" of use also is ignored here, because users with no ready substitutes for gas usually are curtailed just as severely as boiler fuel users. Over time, curtailments will move down the priority list to smaller users, and supply interruptions will affect more users for longer periods.

The FPC's curtailment plan should be revised to recognize the chronic nature of the shortage. Priorities should be ordered to indicate clearly just who should receive gas and how much each recipient should get. Boiler fuel uses and other "low-quality" consumption could be eliminated and essential uses protected from shortfalls to the extent possible.

Valuable property rights are created by these decisions, however, and some arbitrary and perhaps capricious awards will be made. Milton Russell has summarized the problem involved:

> The value of this right to gas is substantial... This points up important issues that will continue to bedevil gas regulators: What are appropriate

> criteria for priority access to gas, and what are the proper quantity of special relief to be granted and the proper criteria for granting it? To the extent that some gas is allocated to the "deserving," another group of the dispossessed is created. In property distribution terms, whether this distribution will be perceived as equitable or not is an open question. One thing is certain: Continuation of the current policy, or one similar to it, grants to the FPC enormous economic power in allowing or permitting some firms or individuals to obtain a fuel supply substantially below its opportunity cost. 12/

Russell expresses further concern about the effects of mandatory allocation on income distribution. With the creation of property rights, income in the form of fuel priced below other energy users' cost accrues to those having access to price-controlled gas. Envision two competing firms with one manufacturing a product using an allocation of price-controlled gas and the other less fortunate company burning oil. The firm receiving gas clearly has a production cost advantage vis-a-vis its oil-using competitor, and this will show up in higher profits for the firm awarded gas. In effect, income has been transferred between these firms, or between any other individuals similarly situated in the gas allocation scheme. Russell suggests that these rights to gas be made marketable, so that an optimal allocation of this fuel might be achieved as gas entitlement holders auction off their rights. In this way, gas users who can and want to switch to other fuels or can conserve would be rewarded by the profits from selling gas allocations. Those needing gas enough to pay the higher price could obtain it.

Something of this nature happened during last winter's emergency. Empowered by the Emergency Natural Gas Act of 1977, the FPC approved a temporary sale of intrastate gas which previously had been used by an electric utility at $3.05 per mcf. This price was designed to reimburse the utility for its cost of using residual fuel plus storage costs and compensation for generation efficiency lost.

Similar transactions can be envisioned where the monies are used to pay for coal conversion or energy saving investments. Thus, prices of gas sold by previous end users could be deregulated while prices to field producers remain under limits, offering a cash incentive to firms to convert to other fuels.

This type of transaction illustrates the feasibility of regulatory measures aimed at improving allocation. Regulatory procedures encouraging transactions of this type on an even broader basis should be explored further or perhaps legislatively mandated.

Taxes on Natural Gas

An excise tax, levied at the wellhead or on burner-tip consumption, also could be used to achieve efficient allocation of gas for which producer prices remain controlled at below market-clearing levels. This would do two things:

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o it would tax away the property rights of industrial fuel users endowed with gas and eliminate the relative disadvantage of firms which do not have access to low-cost gas.

o it would foster efficient allocation of gas among consumers through the market mechanism, if the tax were to make gas prices to industrial consumers equivalent to those of light oil fuels. In this way, users would in effect be paying the marginal cost of (imported) light oil fuels.

Taxes could be designed on a State or regional basis to price gas at a level equivalent with oil fuels, thus eliminating regional price inequities. Alternatively, the burner-tip price could be escalated to a point somewhat in excess of the oil equivalent, encouraging users to whom gas is not essential to switch to other fuels. Such taxes should be imposed only gradually over several years, however, to avoid undue burdens on consumers and disruption of the economy.

Other Problems of the Curtailment Policies

The Federal Power Commission implements curtailments of interstate pipeline sales to local gas distribution systems. For the most part, curtailments to actual end users are allocated by these local distributors. The FPC's curtailment priorities do not necessarily determine the pattern of rationing by local utilities.

Another problem not addressed by present curtailment policy is the regional maldistribution of the shortages: certain parts of the country are curtailed more seriously than others, because pipelines serving them have not obtained adequate reserves. While this problem was addressed on a temporary and limited basis by the Emergency Natural Gas Act of 1977, there is a need to turn curtailments -- as long as they are necessary -- into a meaningful conservation tool. The FPC has been unable to do this effectively, and it would appear that a legislative remedy is in order.

11/ Taylor, Lester, The Demand for Energy: A Survey of Price and Income Elasticities, April 1976. Table 4.

12/ Milton, Russell, "Natural Gas Curtailments: Administrative Rationing or Market Allocation?" New Dimensions in Public Utility, Harry Trebing, Editor.

IV. MACROECONOMIC EFFECTS OF ENERGY PRICE INCREASES

The Energy Shocks of 1974-1975

During 1974 and 1975, the prices of oil fuels, unregulated natural gas and coal rose sharply and were a principal cause of that period's extraordinary inflation. Spending for energy in the United States increased by over $50 billion, despite reduced consumption. This sum was composed of the following elements:

o Crude oil prices were controlled in 1971 by the Cost of Living Council (CLC). By 1973, ceilings were at $4.25 per barrel. "New" oil was decontrolled in August 1973, whereupon its price began to rise and continued to increase. With the $2 tariff imposed by President Ford, which was in effect through most of 1975, uncontrolled domestic crude sold for $13 per barrel. An average of three million barrels per day (mbd) of new oil was produced during this period. Thus, at an annual rate, the total bill for deregulation of new oil plus the tariff was about $9.6 billion. 13/

o Just before its merger into the Federal Energy Administration (FEA), the CLC increased "old" oil prices by $1 per barrel, from $4.25 to $5.25. About 5.5 mbd of old oil were involved. The increase in cost from this action is estimated roughly at an annual rate of $2 billion.

o During 1974 and 1975, wholesale prices of refined oil products increased by almost 4 cents per gallon more than a passthrough of these crude oil price hikes would have dictated. These increases in refinery margins were due to higher operating costs, higher profits and the fact that price controls on refined products were not entirely effective. With about 230 billion gallons per year refined in the U.S. during this period, $9.2 billion annually were paid in higher wholesale oil fuel prices.

o Foreign oil increased from a pre-embargo price of $3 or so per barrel, to an average level of $15, including tariffs by the second quarter of 1975. Roughly 6.5 mbd of crude and foreign refined products embodying this expensive crude were imported. The total increase in cost was some $28.5 billion at an annual rate by the end of 1975.

o Oil has a clear-cut role in influencing price levels for other energy sources. Rising oil prices have drawn unregulated natural gas prices upward. About 9 trillion cubic feet (or billion mcf.) were involved in unregulated intrastate sales. Prices had, on average, increased from about 55 cents per mcf. to an estimated $1. Thus, a rough estimate of the contribution of intrastate gas to the energy cost inflation would be about $4.1 billion at an annual rate.

o Coal also is influenced by oil prices. According to Federal Power Commission statistics covering about 60 percent of domestic coal consumption, coal prices climbed from an average of $9 per ton at the end of 1973, to $18.50 by late 1975. Extrapolating this to roughly 450 million tons of coal consumed annually as boiler fuel, we find the aggregate cost increase to be about $4.3 billion.

In a rough way, these estimates delineate the aggregate cost impact of energy price increases during the two years after the

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embargo. Recapitulating these components, we find that they sum to $57.7 billion as follows:

Domestic uncontrolled crude	$ 9.6 bil.
Old oil increase	2.0 "
Refiner margins	9.2 "
Imported oil	28.5 "
Unregulated natural gas	4.1 "
Coal	4.3 "
	$57.7 bil.

Between the end of 1973 and the end of 1975, the GNP deflator rose by 18.3 percent, real GNP itself declined 1.9 percent, and unemployment rose from 4.8 percent to 8.3 percent (down from 8.9 percent in May 1975). This 18.3 percent inflationary increase in GNP amounted to some $290 billion annually between the end of 1971 and the end of 1975. Energy comprised $58 of the $290 billion. Thus, energy price increases accounted directly for nearly one-fifth of the 1974-75 inflation. The direct plus the secondary (or ripple) effects of the price increases, aggravated by the draconian monetary policy of that period, accounted for perhaps one-half of the inflation and the decline in GNP during these two years. 13/ It comprises an illustration of what energy price shock can do to the economy.

Energy shock's recessionary effects arose in several ways. As prices rose, purchasing power was drained out of the country to pay for oil imports. Higher domestic oil prices yielded increased profits and savings for oil companies, which were not promptly reinvested. Consumers reacted to the higher prices by buying slightly less energy, but their energy expenditures rose sharply. At the same time, other prices also were going up. Thus, less real purchasing power remained to spend on other things, so that real consumption declined.

An extremely tight monetary policy during 1974 and 1975 decreased the supply of money. With real money balances declining in the face of increased demand for money to pay the higher energy and other prices, further contractionary forces were set to work. Interest rates rose, and a liquidity shortage cut off new investment.

Potential Gas Price Shocks

There are two sources from which substantial gas price increases can be anticipated. One is already programmed, stemming from past regulatory decisions, and the second is implied by legislative proposals now under serious consideration, which would raise price ceilings on "new" gas again or eliminate them altogether. This section tallies up the potential costs of gas price increases under alternative future pricing regimes. Among them are certain potential loopholes that may permit large amounts of already flowing gas to qualify for new gas prices unless they are excluded by law or administrative ruling.

The Present Rate Structure

As we saw in Chapter I, as old gas averaging 50 cents per mcf. is replaced by new gas at $1.42 per mcf. plus adjustments, interstate users will be paying over $10 billion per year more for today's volume of consumption. Barring legislated change in regulatory procedures, a new still higher price may be set for gas brought into production in 1977 and 1978, although hearings for a new national rate are just getting under way. It is assured, therefore, that interstate consumers will pay substantially more than they are paying now, even without legislative changes, and increasingly higher biennial rates for future vintages will raise average prices continually.

Estimating Deregulation Costs

There have been numerous proposals for deregulation or changes in the guidelines for regulation of new natural gas prices. The key variables in computing deregulation costs are:

(1) The definition of new gas, which determines the volume of gas subject to price increases;

(2) The ceiling or market-clearing level to which prices would rise;

(3) Whether intrastate gas is included under any ceiling that is imposed;

(4) What provisions are made to require delivery of old gas at previously contracted prices.

The outright deregulation scenario assumes that the Department of Energy is relieved of all responsibilities to regulate wellhead prices. Under this scenario, forces are set in motion which cause both interstate and intrastate gas prices to rise. The following cost elements must be considered:

Intrastate Gas. Interstate pipelines, hard pressed for new supplies, would bid for gas heretofore confined to intrastate markets. Given limited supplies and the relative price flexibility under intrastate gas contracts, prices would rise quickly. New and renegotiated intrastate prices now average about $1.85 per mcf. Without constraints on interstate prices, buyers competing in a sellers' market would drive wellhead prices up to the level at which gas delivered to industrial users -- the consumers most likely to switch to other fuels -- sells at a moderate premium over light oil fuels. Thus virtually all intrastate supplies easily could rise to the $3 range within a short period. With present consumption at 8 tcf., the total cost to intrastate consumers of such a price rise would be about $9.2 billion. The full effects of this increase could be felt within perhaps two years, as existing intrastate contracts are broken and renegotiated and as prices are escalated under a variety of provisions facilitating such adjustments.

Intrastate gas consumers have long been unintended beneficiaries of Federal interstate regulation, both through lower prices than otherwise would have prevailed and through the benefit of ample gas supplies. They would be among the largest losers from a policy of deregulation. Consumers in these markets, previously protected from outside demand, would quickly recognize how a completely unregulated market for natural gas affects them.

"Rolling Over" Interstate Contracts. Under present FPC practice, as older contracts between producers and interstate pipelines expire, this gas continues to flow in interstate commerce at 52 cents per mfc.

With deregulation, this price limitation would be terminated and the prices for these supplies also could rise to the $3 scarcity level.

Table 13 shows the volumes of gas under contracts to be rolled over each year through 1981. The cumulative flowing gas has been estimated based on a 7 percent decline rate for the amounts eligible to roll over in each year. Dollar costs for potential price escalation affecting this gas shown in Table 14 below, are projected based on the amount of gas rolled over by 1978 and 1979 and on an assumed price rise from 52 cents to $3 per mcf. Calculations reflect three assumptions: (1) that this old gas would be produced at 52 cents under regulation; (2) that the additional $2.48 per mcf. would add nothing to the volume of production in this category; and (3) that roll-overs would add to gas costs only during 1978 and 1979 because, by 1980, all of this gas would be liberated by other means from whatever contracts had bound its price. Producers would accomplish this by redrilling fields or shutting in this old gas and replacing it with new.

<u>New Interstate Gas</u>. As production from old wells in given fields declines, new wells are drilled, tapping both known and new reserves. About 80 percent of the new reserves are from extensions of old fields through additional development drilling. Table 7 showed both the limited size of new field discoveries and the relatively large reserve additions from extensions and revisions of existing fields.

Gas discovered as an extension of old fields, however, is different from new field discoveries in that the latter require much riskier, "wildcat" drilling. Nevertheless,

Table 13. Roll-Over of Old Interstate and Flowing Volumes
(billion cubic feet)

Year	First Rolled-Over In Current Year	Cumulative Flowing Gas
1974	381	
1975	175	529
1976	120	612
1977	285	854
1978	282	1077
1979	347	1348
1980	383	1637
1981	261	1783

Source: Estimated from Appendix A of FPC Opinion 699H using a percent decline rate.

under present regulations and also with decontrol, no price distinction is made between new gas that is hard to find and gas which is much less risky and expensive to produce.

It is in part for this reason that some new gas has been dedicated to the interstate market even under FPC regulation. We estimate that one tcf. per year of new gas production would be available to the interstate market at the present national ceiling of $1.42 plus adjustments. Given the limitations of the resource base discussed in Chapter II, very little additional gas can be expected to appear in response to price increases above these levels in real dollar terms. Thus we can consider any escalation of new gas prices as a pure scarcity payment. The amount of this payment would rise at about $1.5 billion per year from the date of deregulation.

Renegotiated Interstate Contracts. A recent study by the General Accounting Office (GAO) established that many existing interstate contracts have pricing clauses that facilitate price escalation in the event of deregulation. The FPC has acquiesced in this practice in violation of its own rules which prohibit the activation of escalators not specifically mandated by Commission-approved tariff rulings. 14/ The amounts of old gas and prices to which they might be adjusted could be limited, however, by statute or by FPC administrative measures. Under deregulation, which would relieve the FPC of its responsibilities, it is likely that several types of escalators would come into play:

- o renegotiation clauses that allow for price changes on some specific date;

- o redetermination clauses, which are similar in effect to renegotiation clauses and provide for adjustments to a "fair market price" or some negotiated price that may be higher than the pre-existing FPC ceiling;

- o so-called "most-favored-nation" clauses, which allow for increased rates if prices in other contracts in the area rise;

- o deregulation clauses which permit higher prices in the event regulatory control is removed;

- o area-rate clauses which allow old gas prices to escalate in the future to rates established by FPC for the area covered by the contract.

GAO also notes that only the area-rate clause appears to be permissible under FPC administrative regulations. Furthermore, the GAO reports that:

- o 26 percent of the interstate gas supplies now are sold under contracts having renegotiation or redetermination clauses;

- o 10 percent are under contract with most-favored-nation clauses;

- o 2 percent are under contracts having deregulation clauses;

Thus, more than one-third of all interstate gas supplies are affected by these clauses. Some contracts, however, contain more than one such escalator provision. We estimate that some 3.8 tcf. of existing interstate gas supplies would rise in price during the first year of deregulation, unless the deregulation statute specifically prohibits these increases. With this gas today averaging less than 50 cents per mcf., a projected increase of $2.50 per mcf. would cost gas users $9.5 billion annually. This extra sum would be paid for gas discovered and developed at yesteryear's costs and already committed to interstate commerce. Thus, it would be purely a scarcity premium deregulation.

Redrilling of Old Fields. "New" natural gas has been defined by the FPC as gas from a new well, spudded on or after a specified date. In Opinion 770A, this definition was modified to exclude recompletions of existing wells to tap shallower gas-bearing strata through which the well already passes but from which no output is withdrawn. As the price differential between old and new gas widens, incentives to drill new wells to tap "old" reserves become greater. This is clearly the easiest and cheapest way to obtain new gas, and with the trebeling of regulated new gas prices since 1974 some drilling of this type undoubtedly has been occurring. Statistics on drilling and reserve addition lend credence to this theory. As Table 6 and 7 show, a large number of gas wells has been drilled and completed in recent years with disproportionately small reserve additions. One can infer, among other reasons for the apparent low productivity of drilling, that some of these wells were drilled to obtain "new" gas from old (already proven) reserves. Unless legislation prohibits this tactic explicitly, we believe that 1 tcf. per year of gas will be liberated from current price ceilings in this fashion. It will rise from an estimated average of 50 cents per mcf. to a projected level of $3.

Table 14 summarizes the total effect of these various factors which will act together to raise gas costs. Under unqualified deregulation, gas users will be paying an estimated $21 billion in higher prices in 1978 and $30 billion in 1979. We estimate that deregulation will cost $35 billion by 1980. This will be $25 billion more than would be paid under the status quo.

The impact of price increases of this size on the economy can only add to inflation, while disrupting and reducing production and employment. Although smaller in total cost that the 1974-75 energy price rise, and while affecting an economy that is 25 to 30 percent larger in current dollars, these price increases would raise the general price indices by up to 1-1/2 percentage points in 1978 and by a but slightly smaller amount in 1979. Such price increases will come in addition to substantial preprogramed oil price increases and the effect of any excise taxes on oil that are phased in under the National Energy Act now being considered by Congress.

As Table 14 shows, a substantial part of the potential cost of deregulation could result from renegotiation of prices for already flowing gas under existing contracts and redrilling of old gas fields to extract "new" gas from already established reserves. Not only will producers collect scarcity rents on old gas by these methods, but the economy will be subject to unnecessary inflationary drag. Responsible natural gas legislation should address these problems. By limiting these possibilities, the

Table 14. Deregulation Cost Summary

Cost Element	1978 Vol(tcf)	1978 $(bil)	1979 Vol(tcf)	1979 $(bil)
Intrastate Gas	4.0	$4.6	8.0	$9.2
Rolled Over Gas	1.1	2.7	1.3	3.4
Renegotiated Contracts	3.8	9.5	3.8	9.5
New Gas	1.0	1.5	2.0	3.0
Redrilling of old Fields for Definitionally new Gas	1.0	2.5	2.0	5.0
Total	10.9	$20.8	17.1	$30.1

Source: Author's calculations

potential cost could be cut by half or more. These issues will be elaborated somewhat in Chapter V.

Excise Taxes on Natural Gas and Oil

In Chapter 3 the concept of a gas tax was discussed. Such a tax would effectively bring controlled gas prices up to market-clearing levels. Depending on the size of the differential to be taxed away, the tax could generate very large revenues as well as raise prices to gas consumers markedly. Two potential problems exist with this approach:

(i) large revenue collections require fiscal measures to recycle the monies quickly back into the economy so that purchasing power is not reduced, and contractionary forces are not set in motion.

(ii) large price increases in a primary commodity such as gas will effect the general price level. As gas price increases work their way up through the stages of production to finished goals, these inflationary effects become enlarged. It is important, therefore, to phase in a tax of this nature gradually in order to spread its impact over time.

Extreme care should be taken in levying any gas price equalization tax so that inflationary forces are kept in check. Compensatory monetary and fiscal measures, to offset any contractionary forces, should be worked out in advance and planned for sequential implementation.

The National Energy Plan's proposed gas use tax is conceptually similar to what has been discussed. Under the House-passed bill (H.R. 8444), industrial gas use would be taxed up to the price of distillate fuel oil, including the proposed crude oil equalization tax. Incremental pricing, described in Chapter V, would also act to raise industrial gas prices. Depending on how much new gas comes on line and how much of the crude oil levy would be passed on to distillate prices, the gas use tax could be very small. But in any case, even if the use tax is relatively large, it is phased in relatively slowly through several tiers of user types, and does not become fully effective until 1985. While the use tax may have significant microeconomic impact on affected firms, its direct impact on the general price level will be distributed over a number of years.

The National Energy Act

The National Energy Act proposed by President Carter, contains the following four primary elements for gas:

(i) A new national ceiling price set at Btu equivalency with the refiner acquisition cost of domestically produced crude oil (excluding Alaskan output). This would start at $1.75 per mcf. equivalent in 1978 and rise proportionately with the EPCA composite. The composite price can be expected to rise at 10 percent per year with the inclusion of third tier ("new, new") crude oil.

(ii) The ceiling would include intrastate gas.

(iii) Rolled over old gas contracts would be permitted to rise to $1.45 per mcf.

(iv) Provision is made for the granting of unregulated prices to expensive gas production from Devonian shale, deep wells, and beneath deep water. We estimate that nearly 3 tcf. per year of this production will occur by 1985.

The $1.75 per mcf. initial new gas price will rise in real terms, assuming that it keeps pace with the 10 percent per annum nominal increase in the EPCA composite price for oil. Assuming that inflation averages 5 percent yearly over the time frame until 1985, the $1.75 price will grow at 5 percent yearly in real terms.

Production will be enhanced by granting the unregulated price of $3.00 per mcf. for high cost gas. We estimate that 0.5 tcf. of this gas will begin to flow in 1980, and flowing volume will grow to 3.0 tcf. in 1985. It will replace old gas now flowing at $0.45 per mcf., which will be depleted.

Table 15 shows the cost of each of these elements during the next seven years. Table 15 should be compared with the figures in Table 14. Under the open-ended deregulation scenario, the full cost is $35 billion per year in terms of prices above present levels (in 1977 dollars) by 1980 and each year thereafter. These costs are substantially above those of the Carter proposal for approximately the same amount of gas.

13/ 3 mbd x 365 days per year x ($13.00 - $4.25) = $9.6 billion per year.

14/ The Data Resources Review, November 1975. See "OPEC's Impact." Data Resources estimates that one-half to two-thirds of 1975's inflation was due to higher energy prices.

15/ General Accounting Office, Selected Contract Sales Information Related to the Deregulation of Natural Gas.

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TABLE 15. ADMINISTRATION'S GAS PROPOSAL -
COSTS ABOVE PRESENT (billions of 1977 dollars)

Year	New Interstate Gas		Price	New Intrastate Gas		Rolled Over Old Interstate Contracts		High Cost Gas at $3.00		Total Cost
	tcf	cost	$ per mcf	tcf	cost	tcf	cost	tcf	cost	
1978	.5	.2	1.75	.5	---	1.1	1.0	---	---	1.2
1979	1.0	.4	1.84	1.0	.1	1.3	1.2	---	---	1.7
1980	1.5	.7	1.93	1.5	.3	1.6	1.5	0.5	1.3	3.8
1981	2.0	1.2	2.03	2.0	.6	1.8	1.6	1.0	2.6	6.0
1982	2.5	1.7	2.13	2.5	1.0	1.9	1.7	1.5	3.9	8.3
1983	3.0	2.4	2.24	3.0	1.5	2.0	1.8	2.0	5.1	10.8
1984	3.5	3.2	2.35	3.5	2.1	2.1	1.9	2.5	6.4	13.6
1985	4.0	4.1	2.47	4.0	2.9	2.2	2.0	3.0	7.7	16.7

V. MEASURES TO RESOLVE THE CURRENT PROBLEMS

How can the problems of short gas supplies and mining prices be mitigated? A number of measures may be adopted to limit price impacts on individuals and the economy while maintaining production and achieving a proper allocation of this premium fuel, which is likely to be in persistently short supply.

Unifying Gas Markets

A first step required to move toward these goals is unification of the divided natural gas market. Division of the current market into many submarkets by State lines makes proper allocation impossible. Shortages exist in nonproducing States, while electric utilities in producing states use nearly 2 tcf. per year under boilers at prices around $1 per mcf. As a starting point, it seems obvious that the interstate-intrastate dichotomy must be ended and this barrier to proper allocation removed.

The Need for a Wellhead Price Ceiling

There is no competitive market for oil and gas in the world today. There is no world without price controls. Either the U.S. Government sets certain maximum gas prices or we shall pay prices set indirectly by OPEC. The choice is whether the American producer should be permitted to ride on OPEC's coattails, while the U.S. economy suffers from a new energy price shock and U.S. consumers pay cartel prices for gas from their own national patrimony (even from Federal lands), or whether producers and/or consumers will face prices administered by our Government. Because of the recent large price rises and the limited response of supply to higher prices, the supply payoff to still higher prices is questionable.

Choosing the appropriate ceiling price is not easy. Chart 1 gave an idea of recent thinking at the Federal Energy Administration (FEA) on what it should be. No doubt other gas experts have other views. Implicit in the Administration's proposal of a ceiling price at $1.75 per mcf. (which would escalate with the controlled price of crude) is that price increases beyond this level are not cost-effective in bringing forth more production. This thinking is supported by FEA's estimates of the supply response, as Chapter 2 discusses.

A number of other gas ceiling price concepts have been discussed. Usually these limits are associated with Btu equivalency with oil fuels of some type. They must be considered in view of the fact that wellhead prices of domestic crude oil are under control and will remain so if the President's proposal is accepted. Gas prices could be related to crude oil in some fashion or to the prices of refined oil products.

- o Lower-tier crude -- Prices of lower-tier or "old" oil are controlled at the wellhead at about $5.20 per barrel. This translates into a Btu-equivalent of 90 cents per mcf. for natural gas. It might be appropriate to have parity between old oil and old gas on producer equity grounds. This is close to the intra-interstate old gas blend price today.

- Upper-tier crude -- Prices of upper-tier or "new" oil are controlled at about $11.60 per barrel. This translates into a Btu-equivalent of $2 per mcf. Again, on equity grounds, it might be desirable to have parity between producer prices for new oil and new gas.

- Stripper-well oil -- Uncontrolled since 1976, this crude now sells for about $13.50 per barrel or the equivalent of $2.35 per mcf. A ceiling on new gas prices at this level would prevent scarcity pricing above oil equivalency, while still providing the price equivalent of unregulated oil.

- The EPCA composite -- Under the Energy Policy and Conservation Act (EPCA), domestic controlled oil now sells for a weighted average wellhead price of about $8 per barrel, or the equivalent of $1.40 per mcf.

- The average price of domestic oil -- Due to the exemption from control of stripper-well oil, this blend price is slightly above the EPCA composite and translates to about $1.45 per mcf.

- Refiner acquisition cost of U.S. crude -- This price, which includes some transportation costs, is currently about $9.20 per barrel, roughly the equivalent of $1.60 per mcf. With the permitted adjustments of the EPCA composite, this should rise to about $10.15 per barrel during 1978, which is the equivalent per Btu of the $1.75 per mcf. proposed by the President in the National Energy Act. Used as a politically acceptable figure by the

Administration, it provides a compromise price for conventional gas supplies.

- Refiner acquisition cost of all crude oil -- The average refinery price of all domestic and foreign crudes refined in the U.S. is about $11.70 per barrel, the equivalent of gas at $2 per mcf. This would price gas on parity with the blended price of all crude oil used in the nation, eliminating the relative disadvantage of those unable to obtain gas.

Refined oil fuel prices that could serve as guidelines in setting a ceiling for natural gas prices are:

- Residual Fuel Oil -- In the view of some observers, residual fuel oil is the alternative fuel for marginal users of natural gas. At roughly $13.50 per barrel for residual oil with a one-percent sulphur content (and an energy content of about 6-1/4 million Btus per barrel), the equivalent natural gas price would be $2.15 per mcf. delivered to the industrial users. A transportation (pipelining) charge of at least 50 cents per mcf. must be deducted to derive the implied wellhead gas price of almost $1.65 per mcf. This is a useful reference price because some large gas users -- especially boiler fuel users -- convert to residual when curtailed.

- Middle Distillate -- Light fuel oils are close and readily available substitute fuels for many industrial users whose gas supplies are curtailed. At 40 cents per gallon or $16.80 per barrel delivered to industrial users, this translates into \$2.90 per mcf. for delivered gas and about \$2.40 per mcf. at the wellhead.

- o Propane or LP gas -- These fuels typically are the first choice as gas substitutes, although they are in very limited supply and are subject to FEA allocation. Prices vary widely, but delivered prices to industrial users should average about 30 cents per gallon. This is the equivalent of natural gas delivered at \$3.15 per mcf., or a wellhead price about \$2.65. While this is the marginal cost of alternative fuel for many users, relatively small amounts are available to such users.

Intrastate gas prices are often held to be the "free market" price for gas. The most recent data (covering the first quarter of 1977) show average in-state prices of \$1.85 per mcf. for new and renegotiated contracts. This figure may have been bid up somewhat by last winter's extremely high gas demand. On the other hand, intrastate prices have been held down by the fact that intrastate supplies are protected from out-of-state demand through Federal price controls.

All of the oil-equivalent prices (except those related to oil at the wellhead) will rise if the crude oil equalization tax is enacted in a form similar to what the President has recommended and the House of Representatives has passed.

This list suggests the range of prices which could serve as a basis for a new natural gas price ceiling. Each of them would equalize gas prices per Btu with crude oil or refined oil prices. Such an equalization would yield a more efficient allocation of demand and of production resources, and would prevent interstate pipelines from bidding prices far above Btu-equivalent levels.

Defining New Gas

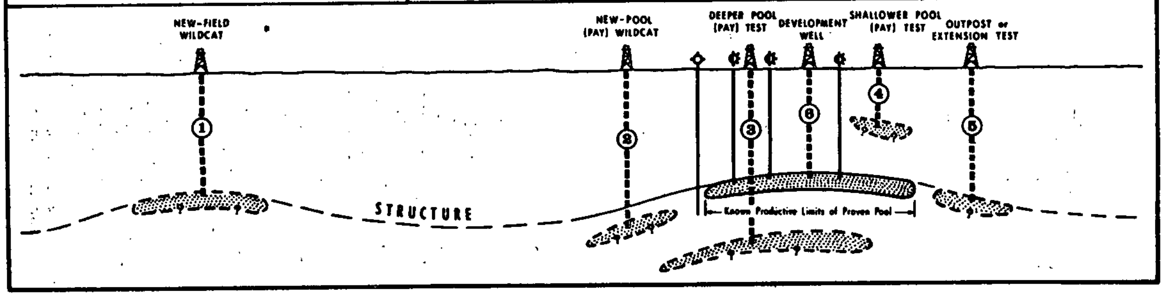
The most important variable in computing the cost of various proposals to raise gas prices is the language that determines how much gas will qualify for the higher rates. If very little gas is eligible, the aggregate impact can be small, even with a very high new gas price. Conversely, if relatively large amounts of old gas are allowed to rise in price over a short period, consumer costs and economic disruption can be large.

The potential for price adjustments on large quantities of gas derives from two sources: contracts which permit escalation of flowing gas prices in the event of deregulation or other new gas price increases, and loose definitions of new gas. A loose definition would the qualify already known reserves as new gas. Sponsors of such language would, however, claim that only "new" gas would be eligible for higher prices. There are great differences of opinion as to what should and should not qualify as new gas. What is thought of as new gas by producers is considered to be old gas by many consumer groups.

Figure 3 shows six general classes of drilling activity. For many partisans of the gas industry, new gas is that from any new well in any formation because drilling any well involves expenditure of new capital. For others, newly discovered gas is that from

FIGURE 3. CLASSIFICATION OF GAS WELLS

<table>
<tr><th colspan="4" rowspan="2">OBJECTIVE OF DRILLING</th><th rowspan="2">INITIAL CLASSIFICATION ϕ
WHEN DRILLING IS STARTED</th><th colspan="4">FINAL CLASSIFICATION
AFTER COMPLETION OR ABANDONMENT</th></tr>
<tr><th colspan="2">SUCCESSFUL ● ☼ ☼</th><th colspan="2">UNSUCCESSFUL ◇</th></tr>
<tr><td colspan="4">Drilling for a new field on a structure or in an environment never before productive</td><td>1. NEW-FIELD WILDCAT</td><td colspan="2">NEW-FIELD DISCOVERY WILDCAT</td><td colspan="2">DRY NEW-FIELD WILDCAT</td></tr>
<tr><td rowspan="3">Drilling for a new pool on a structure or in a geological environment already productive</td><td rowspan="3">NEW POOL TESTS</td><td colspan="2">Drilling outside limits of a proved area of pool</td><td>2. NEW-POOL (PAY) WILDCAT</td><td rowspan="3">NEW-POOL DISCOVERY WELLS (Sometimes extension wells)</td><td>NEW-POOL DISCOVERY WILDCAT (Sometimes an extension well)</td><td rowspan="3">DRY NEW-POOL TESTS</td><td>DRY NEW-POOL WILDCAT</td></tr>
<tr><td rowspan="2">Drilling inside limits of proved area of pool</td><td>For a new pool below deepest proven pool</td><td>3. DEEPER POOL (PAY) TEST</td><td>DEEPER POOL DISCOVERY WELL</td><td>DRY DEEPER POOL TEST</td></tr>
<tr><td>For a new pool above deepest proven pool</td><td>4. SHALLOWER POOL (PAY) TEST</td><td>SHALLOWER POOL DISCOVERY WELL</td><td>DRY SHALLOWER POOL TEST</td></tr>
<tr><td colspan="4">Drilling for long extension of a partly developed pool</td><td>5. OUTPOST or EXTENSION TEST</td><td colspan="2">EXTENSION WELL (Sometimes a new-pool discovery well)</td><td colspan="2">DRY OUTPOST OR DRY EXTENSION TEST</td></tr>
<tr><td colspan="4">Drilling to exploit or develop a hydrocarbon accumulation discovered by previous drilling</td><td>6. DEVELOPMENT WELL</td><td colspan="2">DEVELOPMENT WELL</td><td colspan="2">DRY DEVELOPMENT WELL</td></tr>
</table>



Source: American Association of Petroleum Geologists Bulletin, August 1974 a newly discovered pool, even if the pool is in an old, already known field. Similarly, a new extension of an existing pool might be considered to yield new gas. The most strict definition of new gas, however, is that from a new pool in a new field. This is the most important type of discovery and, during recent years, the most rare. Table 6 indicates that only a small fraction of annual reserve additions come from truly new fields. Most reserve additions have come from development drilling or extensions of old fields and from new pools found in old fields.

Narrowing the new gas definition to exclude reserves added via extension and development drilling reduces the amount of new gas by perhaps 60 percent from what it would be if all reserve additions qualified. This helps to focus drilling activity on finding new pools. It also reserves high wellhead prices for gas for which the risk and thus the costs, are greatest. Moreover, it would lighten the burden of higher gas prices on consumers and the economy.

While the limiting of higher prices to new pool discoveries helps focus drilling efforts on truly new gas, a definition aimed at encouraging exploration for and development of completely new, geographically distant fields addresses the supply problem even more incisively. Because drilling above, below and around known producing areas carries a higher probability of success and lower probability of a dry hole than drilling in entirely new fields, the risks and costs are lower, and prices therefore need not be so high to provide the needed incentive. Full exploitation of already known producing areas should be profitable at or near present prices. It makes sense, however, to provide much higher prices for gas from new field wildcat wells, because without higher prices many new fields might not be discovered.

The Administration's New Gas Definition

In the proposed National Energy Act, the Administration has suggested a new gas definition embodying the essence of incentive pricing for truly new gas. Only gas from new wells 2-1/2 miles or more from the nearest old well or 1000 feet deeper would be eligible for the incentive rate. This provision encourages producers to direct exploratory efforts outside the perimeters of existing fields, as well as deep underneath known hydrocarbon deposits. By the same token, less risky lower-cost activity in known fields would not be overcompensated by eligibility for the incentive price.

The New Oil Definition

In distinguishing new from old crude oil the FEA has adopted a definition based on property lines. Under this definition, production from a new property (where there has never before been production) is rewarded with an incentive price. Such a concept creates incentives to lease mineral rights and explore in previously unexplored locations, thus fostering the search for truly new resources.

Price Adjustments Under Existing Contracts

The study by the General Accounting Office cited above indicates that the potential scope of gas price increases is considerably expanded by the fact that gas producers have long anticipated sharply higher prices and have written both inter- and intrastate contracts with this in mind. Most intrastate gas and about one-third of the interstate gas flows under contracts with adjustable pricing provisions that permit escalation of old gas prices as those for new gas go up. These clauses would permit escalations in the prices of much already flowing gas to occur a year or two after new prices rise.

The Emergency National Gas Act of 1977 contains language which attempts to prevent this. Section 9 of the Act prohibits exercise of escalation or termination clauses which otherwise would be brought into force by the higher prices paid under this legislation.

Because an estimated 12 tcf. per year are sold under interstate and intrastate contracts containing flexible pricing clauses, inclusion of language specifically prohibiting the operation of escalation clauses in any bill raising new gas prices is an important step in holding down old gas prices. Such language would be especially important to protect intrastate markets.

Incremental Pricing

A proposal often discussed for limiting the effects of higher gas prices on homeowners is so-called "incremental pricing" to industrial users. Under this plan, the higher costs of new gas would be allocated to industrial users only. Proponents of this scheme claim that it has three benefits:

-- it protects residential users from price rises for some time;

-- it tends to prevent pipelines from buying gas at prices substantially above the oil equivalent, because such gas would not remain competitive at higher prices as the new gas becomes a major fraction of industrial supplies;

-- intrastate consumers also are protected from prices significantly above the oil equivalent, because interstate pipelines will not drive intrastate prices markedly above these levels.

In reality, these advantages are not as clear cut as the proposal's supporters hold. Gas utilities sell about 7 tcf. per year to industrial users. Thus, substantial volumes of new gas priced above the oil equivalent could be blended in without pricing the gas out of the market. Average gas prices could rise considerably above oil before fuel switching would be economically warranted. In periods of physical scarcity, moreover, competition among pipelines, if unrestrained, could boost the price of new gas supplies beyond the level of oil.

If pipeline systems, for instance, add 3 tcf. of new gas over a two or three year period, even at prices of $5 per mcf., this gas will be blended with the remaining 4 tcf. of old gas at 50 cents per mcf. for industrial consumers. The composite wellhead price would be $2.40. Pipelines will have paid prices much higher than oil equivalency for the new supplies but no industrial user will pay anything near the true incremental price. Such a system, therefore, would not necessarily impose restraint on gas pipeline's bidding for supplies in the initial years of the new regulations. Consequently, intrastate consumers will not be very well protected by incremental pricing if there are no ceilings on instate prices and no restraints on interstate pipeline purchases.

Protecting Intrastate Gas Consumers

As intrastate prices have risen, calls for some sort of protection have come from consumers in most of the producing states. The New Mexico Legislature, in fact, has imposed a ceiling on instate gas prices, setting it at the FPC's latest national rate. Recent proposals before Congress seem to recognize the need to protect consumers of intrastate gas, either by applying a nationwide ceiling both to intra- and interstate markets or by freezing old intrastate gas prices in one manner or another.

The application of nationwide ceilings would appear to be in order. This not only would provide equal protection for all consumers from cartel-dominated prices but also would relieve the misallocation of supplies which has arisen from buyers in an uncontrolled submarket bidding gas away from the controlled interstate market. The proposal to protect intrastate gas users by imposing a ceiling on old intrastate gas prices has been dealt with above.

Tax Changes

There are several tax proposals which are currently under discussion which address the potential windfalls which would result if large amounts of gas suddenly are decontrolled.

A Wellhead Gas Tax

A tax similar in nature to the crude oil equalization tax, has been proposed to capture gas price increases above some base level. This tax would take away the cartel-based profit between the market-clearing price and some stipulated lower level. The base level, which producers would receive, would be adjusted for inflation, and the tax would rise with oil price increases. This system would tax away potential windfalls while simultaneously imposing marginal cost energy pricing to consumers. Little conservation could be expected during the short run, however, in view of low demand elasticities. To avoid economic disruption and inadmissible consequences in terms of inflation, such consumer price increases and excise taxes would have to be introduced gradually and the taxes fully and promptly rebated.

Ending Special Income Tax Treatment for Producers

Under current tax law, gas producers get special advantages which enable them to reduce greatly -- and in many instances to avoid income taxes. Intangible geophysical outlays and dry hole costs, which can be written off during the year incurred, comprise an estimated 71 percent of the industry's investment. The expensing of such large amounts of investment lowers producers' effective tax liability well below the nominal 48 percent corporate rate. This amounts to a subsidy for gas and oil production. If gas prices are to rise for various reasons to a very high, cartelized level, then serious consideration should be given to the design of a tax structure without subsidies.

Special Taxes on Undesirable Gas Uses

Substantial quantities of gas are used in ways that could be satisfied with lower-grade, more readily available fuel. This is true of gas used for boiler fuel by electric utilities and for industrial process heat. The Administration's industrial use tax would discourage this type of consumption via blanket taxation, which would bring the delivered price of gas up to the equivalent of distillate fuel oil (including the crude oil equalization tax). A measure that could reinforce the thrust of this step would be additional taxation of selected undesirable consumption.

Particular attention should be given to exempting from taxation those gas uses for which no substitute is feasible. Processes in which gas is the only fuel or feedstock physically usable should not be taxed -- or should not be taxed as heavily -- because conservation in such cases is possible almost only through reduced output. On the other hand, gas used under boilers can be replaced with oil and in many cases with coal without a significant permanent loss of output.

On the negative side, militating against end use gas taxation as a conservation tool are the low estimated demand elasticities, such as those shown in Tables 11 and 12. If only marginal cuts in consumption can be expected even from large price increases, selective taxation may not be as effective as might be hoped.

Equity Considerations

As natural gas prices rise from their present nationwide average of 90 cents per mcf., it is clear that producer revenues will increase markedly, especially those of the 25 largest firms, which produce 80 percent of the nation's gas. To the extent that these revenues become profits and are not consumed by higher costs, wealth will be redistributed from consumers to producers. Consumers who buy goods and services will ultimately bear the burden of higher gas prices, as the industrial and commercial sectors pass along these fuel costs.

Monies will be redistributed to the gas supply sectors, including those that produce inputs for gas exploration and development. Since these firms and individuals are located largely in the South and Southwest, regional income redistribution can be expected as monies from non-producing States flow to firms and individuals located in the southwestern producing areas. Funds will be geographically redistributed from the "snowbelt" States to the "sunbelt" States.

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