

STATE REGULATORY OPTIONS FOR DEALING
WITH NATURAL GAS WELLHEAD PRICE DEREGULATION

Kevin A. Kelly
Associate Director

J. Stephen Henderson
Senior Institute Economist

Jean-Michel Guldmann
Senior Faculty Associate

Robert E. Burns
Senior Research Associate

Jeffrey Shih
Institute Researcher in
Engineering

Pran K. Paul
Research Associate
in Engineering

Timothy Pryor
Graduate Research Associate

Kyubang Lee
Graduate Research Associate

Yea-Mow Chen
Graduate Research Associate

Martin N. Cristo
Graduate Research Associate

Peter A. Nagler
Graduate Research Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

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EXECUTIVE SUMMARY

This study was undertaken at the request of the NRRI Board of Directors to identify options available to state regulators of natural gas distribution utilities for dealing with federal deregulation of gas wellhead prices. Selecting among options requires an understanding of the causes of the current distortions in the U.S. natural gas market.

The Natural Gas Policy Act (NGPA) was passed by the Congress to deal with the gas shortages and curtailments of the mid-1970s. This act, which merged the then existing intrastate and interstate gas markets, calls for phased, partial deregulation of natural gas wellhead prices. It is phased because deregulation is implemented in stages over the period 1978-87, with the largest deregulation step occurring in 1985. It is partial because not all gas is deregulated in 1987; total deregulation occurs when the last regulated gas well is fully depleted. The NGPA, a compromise between advocates of continued wellhead price regulation and advocates of immediate, total deregulation, has succeeded well in eliminating gas shortages.

Under the NGPA, some twenty-odd categories of gas are established with wellhead ceiling prices that increase monthly according to a formula set out in the legislation. The intent was to have gas prices rise during the 1978-85 period up to the 1985 price of oil, as forecast in 1978. In 1979 and 1980, the world price of oil soared far higher than lawmakers had foreseen. This created a fear that the legislated increases in ceiling prices were inadequate; that is, when the first major deregulatory step is to be taken in 1985, gas prices would "fly-up" in one giant step to the world oil equivalent price. Recent weakness in world oil prices has alleviated but not eliminated this fear.

Another result of soaring oil prices in 1979 and 1980 was that the market-clearing price of gas increased. The NGPA price ceilings, however, prevented prices from rising to the market-clearing level. Consequently, pipelines used various nonprice means to increase the value of their bids--specifically, attractive contract clauses. These included price escalator clauses that allow the price to rise indefinitely after deregulation, most favored nation clauses that guarantee to the producer the best price in his area after deregulation, and take-or-pay clauses that guarantee to the producer the right to sell some quantity of gas in the future, whether before or after deregulation, at the contract price regardless of the quantity customers demand.

Take-or-pay clauses have caused particular controversy, perhaps because they have already affected consumer bills, while the other clauses will not be important to consumers until 1985 or later. The take-or-pay clause, like the other clauses, increases the value of the

contract. In effect, it offers the producer an option to sell gas, and options have a dollar value that can be calculated. Take-or-pay clauses are an entirely legal way for pipelines to offer a value above the NGPA ceiling price in bidding for gas. Options always represent a gamble however. Take-or-pay clauses may not have generated much controversy had not the pipelines lost their gamble: in the early 1980s the economy weakened, gas demand slackened, and oil prices declined. Pipelines were required to cut back on gas purchases; and, rather than incur losses, in some cases they cut back on older, low priced gas in order to honor some producers' options to sell large quantities of new, high priced gas.

Moreover, two factors seem to prevent a remedy for this situation. First, the NGPA states that the Federal Energy Regulatory Commission (FERC) must find any contract price negotiated under the NGPA to be just and reasonable, provided it does not exceed the ceiling price and no misrepresentation was made in the negotiation. Second, the pipeline's FERC-approved tariff for sales to distribution companies contains minimum bill provisions and purchased gas adjustment clauses that seemingly obligate the companies to accept minimum quantities at federally approved prices.

Gas prices have been rising sharply in the early 1980s for several reasons. One, of course, is the monthly increase in NGPA ceiling prices. Also, over the years the mix of gas has shifted from predominantly older, low cost gas, which is gradually depleted, to newer, high cost gas. A third reason, as mentioned, is that contract clauses, particularly take-or-pay clauses, have resulted in an uneconomic ordering of gas supplies, with high cost gas sometimes taken ahead of low cost gas.

In addition to the misordering of gas supplies, several other distortions exist in the U.S. natural gas market and prevent the market--both during and after phased deregulation--from behaving as an ideal free market. Distortions are due to contract clauses that tie gas prices to oil prices, clauses that link gas prices to various inflation indices, rolled-in pricing that allows some gas to be purchased at a price higher than the price it will bring at retail, and various minimum bill and demand charge provisions in pipeline-distributor contracts that partially shield pipelines from the consequences of uneconomic practices.

A regulated monopoly often can live with market distortions, but in the early 1980s the monopoly position of gas distribution utilities was severely eroded in the sense that they faced stiff competition from oil companies for a large share of the boiler fuel market. This threat to distribution utilities creates a problem for state regulators: how to treat the utility's fixed costs of capacity installed to serve the lost boiler fuel load that would be lost.

As a result of these difficulties--rapidly rising gas prices and fear of a 1985 price fly-up, the present and possible future distorting effects of some clauses in producer-pipeline contracts, distortions in the gas market, and the threat of industrial boiler load loss--almost 50 legislative bills were introduced in the U.S. Congress in the first six months of 1983 to repair or replace the NGPA. All of these legislative proposals can be classified as either dealing with (1) wellhead prices, (2) contract clauses, or (3) the position of pipelines in the market. Some bills deal with more than one type of proposal. Each proposal involves a trade-off between increasing market efficiency and protecting the financial interests of some group.

Legislative proposals dealing with wellhead prices fall into one of three categories: extend wellhead price controls further into the future, perhaps indefinitely; stay with the NGPA concept of partial decontrol, perhaps shifting the timing of the decontrol phases; decontrol all wellhead prices, either immediately or over a short implementation period. Of these pricing options, the one that lets the gas market operate with the least distortion is total decontrol; it is most efficient, while extending controls is least efficient in market terms. Price controls with low ceiling prices and with a healthy economy are likely to result in a new round of gas shortages and curtailments in the mid-to-late 1980s. But, under immediate, total decontrol, consumers would pay additional billions of dollars annually to producers for the same commodity. Critics of decontrol argue that this is unfair to consumers and unnecessary, especially for gas from older wells drilled by producers who expected price controls.

Immediate, total wellhead price decontrol may not be sufficient to remove all distortions from the gas market. Other legislative proposals have been introduced to deal with distortions arising from clauses in producer-pipeline contracts or from the market position of the pipelines. Indeed, many bills leave the NGPA essentially intact and focus on one or both of these latter reforms. The most frequent proposal relating to contract clauses is to reduce contractually required gas purchases to some percentage, often 50%, of the volume covered by the contract. No doubt such a reduction increases the efficiency of the gas market by reducing the pipelines' incentives to take gas they cannot sell or to take gas in an uneconomic order. But, producers contend that this action is unfair because they lose the value of options to sell gas as agreed to in the contracts.

Legislative proposals dealing with the position of pipelines in the market are intended to create a true marketplace with many buyers and many sellers. The strongest of these proposals, which would probably result in the most efficient market, is to declare pipelines to be common carriers, authorized to transport gas from producers to buyers at a regulated fee but prohibited from owning any gas themselves. Advocates of this proposal believe that too often only one pipeline is available as a buyer to a producer and as a seller to a

distribution company. A somewhat weaker proposal is to allow pipelines to continue to operate as public utilities, owning much of the gas carried, but to require them in addition to carry gas under contract between a producer and a buyer--so-called contract carriage. The weakest proposals of this type are those requiring contract carriage only for gas that becomes available because of legislatively reduced take-or-pay requirements. While the common carriage proposal is likely to be the most efficient, pipelines contend that it is unfair to them in that much of the value of their business is related to their right to buy gas and that the arbitrary removal of this right is unfair.

The most economically efficient course, which would rid the U.S. gas market of most distortions, appears to be one that asks all three interest groups--producers, pipelines, and gas customers--to give up something of value. But, most public attention has focussed on the proposals dealing with wellhead price controls. An important concern for state regulators is the effect on retail prices of the various federal wellhead price proposals.

The effect of extending price controls depends, of course, on just which prices are regulated. A relevant question concerns the difference in effect between staying with the NGPA and instituting total decontrol.

An examination of three econometric models of the U.S. natural gas market indicates that under medium economic conditions, 1985 city-gate prices would be 0 to 25 percent higher under total decontrol prior to 1985 than under the NGPA, with 12 percent perhaps the most likely result. This is a significant difference in that it results in the transfer of additional billions of dollars annually from ratepayers to gas producers.

But, the difference is small compared to the effect of overall economic conditions. The econometric models were used to analyze the effect on the national average city-gate price of changing from a scenario of low oil price and weak U.S. economy (the low case) to one of high oil price and strong U.S. economy (the high case). Under the NGPA, after accounting for inflation, the 1985 price is about 55 percent higher than the 1980 price in the low case and about 170 percent higher in the high case. Although these forecasts are subject to uncertainty, it is clear that changes in world oil prices and in the state of the U.S. economy will have a far greater impact on gas prices than the choice between the NGPA and total decontrol. To put these figures in some perspective, the actual average annual city-gate price for 1982 was 26 percent above the 1980 price in constant dollars. (The nominal price increase was 48 percent; taking out consumer-price-index inflation, it was 26 percent.) Thus, for the low case prices were about on target if there is to be a 55 percent real price increase by 1985 and so avoid a fly-up in price. For medium economic conditions and for the high case, 1982 prices were below the trend needed to avoid fly-up in 1985.

Under total decontrol prior to 1985, the 1985 city-gate price is about 80 percent above the 1980 level in the low case and 135 percent in the high case. In this forecast, the high case price under total decontrol is less than the NGPA price--at least for the year 1985 when the NGPA produces a temporary price spike. In all the models, prices rise sharply in the year of decontrol, then decline slightly before resuming an upward trend. In all cases, for any one economic scenario, NGPA prices after 1987 are a few percentage points below prices under total decontrol, with the percentage tending to zero as old, controlled gas is depleted.

The NRRI developed a model for studying the effect on retail rates of these various city-gate prices. The model calculates equilibrium values of residential, commercial, and industrial prices and loads for each of ten regional utilities. Among the results is that under medium economic conditions residential gas prices in 1985 are 9 to 14 percent higher across the ten regions under total decontrol prior to 1985 than under the NGPA. Because of price-induced conservation, residential gas bills are only 5 to 9 percent higher. These results contain some regional averaging; customers served by a pipeline with a large proportion of low cost gas in its supply mix could experience larger increases.

Under medium economic conditions, the projected effect of the NGPA in 1985 is to produce industrial load loss of 25 percent or more, relative to 1980 load, for the utilities in four of the ten regions: in the Midwest region (Ohio, Michigan, Indiana, Illinois, Wisconsin, and Minnesota), the industrial load loss is 33 percent; in the Central region (Iowa, Missouri, Kansas, and Nebraska), 25 percent; in the North Central region (Montana, North Dakota, South Dakota, Wyoming, Utah, and Colorado), 46 percent; and in the West region (California, Nevada, Arizona, New Mexico, and Hawaii), 28 percent. Caution is required in interpreting the forecast because economic variables affect the results greatly, because the effects in individual states and utilities can differ greatly from those of the utility studied here, and because of limitations of the data and the need for simplifying assumptions in the model.

The model was also used to study the latitude open to state regulators for saving industrial load by altering traditional cost allocation procedures. Moving from the peak responsibility method of allocating distribution company demand costs to the average-and-excess demand method has only a small effect (about one percent) on the industrial price. But, relieving industrial customers of a large fraction of distribution system costs can result in substantial industrial load recovery. Whether such relief is a wise regulatory policy is another question.

State regulators are concerned about what policy choices are open to them for dealing with natural gas wellhead price deregulation and

its consequences. The range of options depends in part on each regulator's view of his or her own role in shaping utility energy policy. Commissioners who strictly construe the limitations of their authority as set out in state law may consider only those policy options relating to regulatory actions that could be taken by their commission. Others, who see their roles as participants in shaping state or national energy policy, may wish to consider a larger set of policy options, which can be taken up with state or federal legislators. In addition, some commissioners may choose to take a more active role in informing the public about the current natural gas situation, about the likely price changes over the next several years, and about the actions that gas customers themselves can undertake to alleviate the effects of rising gas prices.

A list of commission options is in figure ES-1. Among the options that commissions might find most useful are the following:

- * Use flexible pricing--at least eight states have approved a tariff that allows distribution companies to vary gas rates at will, within floor and ceiling price limits, for some customers with alternate fuel capability.
- * Promote weatherization and conservation programs and low-income heating subsidies--even under moderate economic assumptions large gas price increases are forecast, and existing state and federal programs may be inadequate to provide relief.
- * Alter contract clauses--legislation drafted by the NARUC Committee on Gas and endorsed by the NARUC Executive Committee calls for altering clauses in producer-pipeline contracts that are believed to favor producers unduly.
- * Consider total deregulation--the relatively small effect (relative to the effect of economic conditions) of choosing between total decontrol and the NGPA may not justify continuing NGPA market distortions.
- * Support common or contract carriage--some form of contract carriage may provide useful information on the ability of distribution companies to deal with gas producers.
- * Inform the public--gas customers may have insufficient information about the ability of state regulators to control retail gas rates, about probable future gas rates, and about state and federal programs available for alleviating hardship.

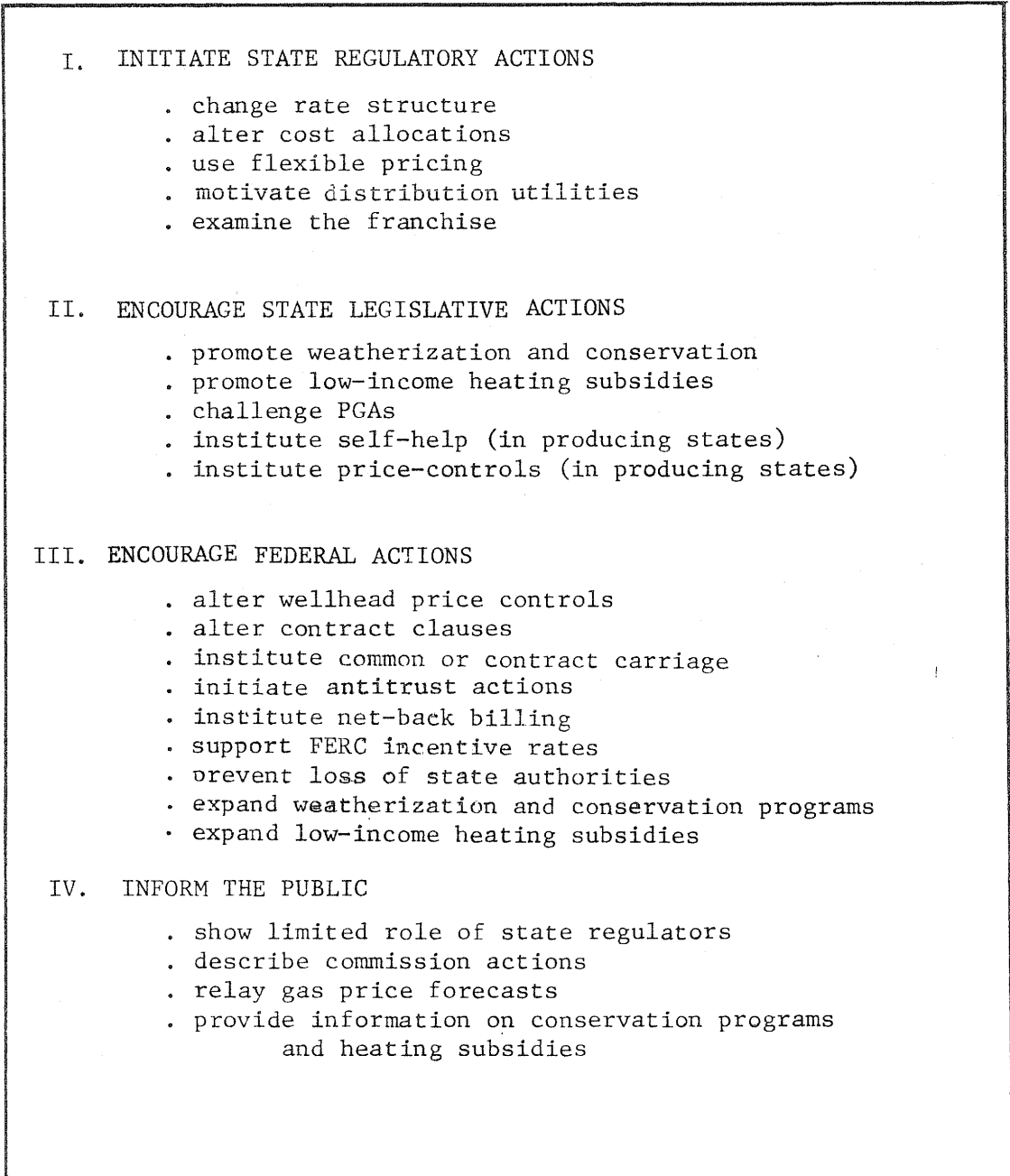


Fig. ES-1 State commission options for dealing with natural gas price deregulation

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Foreword

The bylaws of The National Regulatory Research Institute state that among the purposes of the Institute are:

...to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This report helps meet those purposes, since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with gas utility regulation.

Douglas N. Jones
Director

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CHAPTER 1

INTRODUCTION

The principal objective of this study is to identify the options open to state public utility commissioners for dealing with federal deregulation of natural gas wellhead prices. To assist commissioners in choosing among options, the study contains analyses of existing and possible future difficulties under the current federal law implementing deregulation.

This effort was undertaken at the request of the Board of Directors of The National Regulatory Research Institute (NRRI) at its September 1982 meeting. At this time, natural gas retail rates had been rising rapidly for several years, and it was anticipated that additional dramatic wellhead price increases during the winter of 1982-83 would result in winter heating bills that many residential customers could not pay and in boiler fuel bills that would drive many industrial customers to switch to residual fuel oil. These events did occur, but their severity was limited by mild weather during that winter and by the weakness of the economy--factors that reduced both gas consumption and price increases and that, therefore, tended to reduce bills. In particular, the relatively low price of crude oil on the world market, while exacerbating the problem of industrial fuel switching, acted to hold down gas prices generally, including residential rates. If weather, the U.S. economy, and world oil prices behave differently in the winter of 1983-84, bill increases could be large.

The NRRI Board directed that the study identify actions that state regulators could undertake to protect the interests of retail customers as federal controls over gas producer prices are gradually withdrawn. The policy options available to state commissions are dis-

cussed in chapter 7. Earlier chapters provide information and analyses that may assist state regulators in choosing among these options.

No attempt is made in this study to do a comprehensive analysis of, or even to review, the gas industry generally or its regulation. In particular, federal regulation of production and transmission is treated only insofar as it affects our narrow focus: assisting state regulators to understand and to deal with the impact on retail sales of federal wellhead price deregulation. For a comprehensive analysis of gas industry regulation, see the Natural Gas Regulation Study prepared by the Congressional Research Service and The National Regulatory Research Institute (U.S. Government Printing Office, Washington, D.C.; July 1982).

The main federal legislation that now determines prices in the gas industry is the Natural Gas Policy Act of 1978 (NGPA), which was one of five bills making up the omnibus National Energy Act of that year. Chapter 2 contains a discussion of the intent of the Congress in passing the NGPA and some events that followed its passage and produced controversy. An overview of the principal provisions of this act affecting state regulation is presented. This overview covers the various categories of gas and the schedule for the removal of wellhead price controls for those categories to be decontrolled under the act. It includes a discussion of NGPA limitations on Federal Energy Regulatory Commission (FERC) authority to review negotiated contract prices for gas at the wellhead. Chapter 2 also contains a discussion of the controversial issues that have arisen in the five years since the passage of the NGPA, particularly certain contract clauses in producer-pipeline contracts.

Much of the controversy can be traced to gas market distortions caused by partial regulation; that is, the gas market is now neither

fully regulated from wellhead to burner tip nor fully deregulated. Chapter 3 contains an analysis and explanation of market distortions. It includes both short-term distortions, those that prevent the market from behaving as an efficient, rapidly adjusting, spot market, and long-term distortions, those that prevent the market from reaching its long-term equilibrium.

The controversy over gas price increases, contract clauses, and market distortions has resulted in a variety of proposals for legislative reform of the NGPA. In chapter 4, these various proposals are classified as being related to wellhead prices, being related to contract clauses, or being related to industry structure. Each of the 47 bills before the Congress in June 1983 is discussed as it relates to this classification. Special attention is paid to the Reagan administration bill, the NARUC Executive Committee bill, and the Illinois Commerce Commission bill.

An important question for state regulators is how the various legislative proposals affecting wellhead prices are likely to affect retail gas rates. This question is dealt with in two steps, described in chapters 5 and 6. The first step is to find how city-gate prices are likely to be affected by the various proposals. In chapter 5, city-gate gas price forecasts for ten regions of the United States, developed by three reputable national organizations, are reviewed. Each forecast is based on one of three models with adequate regional and customer class disaggregation, a procedure for balancing supply and demand, and the capability of forecasting the effects of the several principal legislative proposals.

The second step is to move from city-gate prices to retail rates in a way that accurately accounts for the structure of distribution utility costs. A model is presented in chapter 6, which finds residential, commercial, and industrial retail rates for utilities in ten regions of the U.S., given any set of ten utility city-gate prices

from chapter 5. The model is a partial equilibrium model that not only finds retail rates from basic accounting data using accurate cost-of-service allocation procedures, but also automatically adjusts class loads according to the price elasticity of each class, so that the final set of rates and loads meets each utility's revenue requirement. The results derived from the model are also presented in chapter 6. These include the effects of various legislative proposals on retail rates, on customer bills (including the effects of price-induced conservation), and on industrial load loss. The model is also used to examine the degree to which state regulators can affect retail rates by altering cost allocation procedures.

The information and analyses in the first six chapters are intended to provide the background needed for state regulators to make an informed choice among the options, presented in chapter 7, for dealing with natural gas wellhead price deregulation and its consequences. Four sets of options are presented. The first set involves actions that a commission can take under its own authority. These actions include altering rate structures and cost allocations, introducing flexible rates for large volume industrial customers, and providing rewards or penalties for distribution companies according to their ability to find remedies for their difficulties. Another set of options, which can be pursued by either a commission acting formally or a commissioner acting individually, involves encouraging other state authorities--such as the legislature, the governor, or the state energy office--to take actions to deal with rising natural gas rates. Such actions include, for example, augmenting existing weatherization programs and low-income heating subsidies. Similarly, a third set of options involves encouraging federal actions to alleviate state problems under current federal law; important among these actions are possible changes in the NGPA's phased, partial decontrol of wellhead prices. A fourth and last set of options is directed toward the commissioner who chooses to take an active role in informing the public about natural gas pricing issues.

A summary of findings is contained in chapter 8, and a glossary of gas industry terms used in this report is contained in appendix A. Five other appendices provide background and data supporting discussion in individual chapters.

CHAPTER 2

NATURAL GAS DEREGULATION: THE LEGISLATIVE INTENT AND THE ENSUING CONTROVERSIES

The intent of the Congress in enacting the Natural Gas Policy Act of 1978 was to remove the division between the interstate and intrastate gas markets that existed before the enactment of the NGPA and to eliminate the shortages that had developed in the interstate market. The U.S. natural gas market before the enactment of the NGPA was, in effect, two markets. The interstate gas market included all gas carried across a state line by an interstate pipeline and all gas commingled with such interstate gas even if the production and consumption were within a single state. The intrastate market included gas, carried by an intrastate pipeline, that was purchased and delivered within a single state without crossing state lines. Well-head sales of gas in the interstate market were regulated by a federal agency, the Federal Power Commission (FPC), which in 1977 became the Federal Energy Regulatory Commission (FERC). The intrastate market was either deregulated or regulated by state agencies.

Because prices in the interstate gas market were held down before the NGPA by the Federal Power Commission, gas producers tended to dedicate their new reserves in the intrastate market where the gas could command a higher price. By the early 1970s, the demand for interstate gas exceeded the supply. In order to encourage the development of new reserves dedicated to the interstate market, the FPC established a national rate that provided for successively higher prices for new vintages of gas, but these higher prices were still generally lower than those offered in the intrastate market. As a result, shortages occurred in the interstate market. By 1977, interstate pipelines could meet only 75 percent of their contractual

requirements. In order to cope with the crisis in the interstate market, the Congress enacted the Emergency Natural Gas Act of 1977. However, many of the emergency powers granted to the President in the act expired in the spring and summer of 1977. It was therefore necessary to reexamine whether the gas market should be restructured by federal regulation or whether the gas market should be decontrolled. The result of this debate was the enactment of the NGPA. A fuller description of government regulation of the gas industry before the NGPA and of the legislative debate resulting in the NGPA is contained in appendix B.

The current plan for gas wellhead price decontrol is contained in the NGPA. It is the result of a compromise between those interest groups who wanted immediate, total decontrol of all gas and those who wanted continued control of all gas. The compromise that was reached in the NGPA was a phased, partial decontrol of wellhead gas prices. The decontrol is called "phased" in that the NGPA provides for a gradual rise in the ceiling prices of all categories. Decontrol under the NGPA is partial in that not all gas will be deregulated. While the NGPA provides that all new gas will be decontrolled by 1987, some old intrastate gas and all of the old interstate gas will be subject to continued regulation. This is to satisfy both the interest groups who contended that gas wellhead prices must be immediately and totally decontrolled to spur exploration of new gas, and the interest groups who feared that the decontrol of old gas would merely lead to windfall profits for the gas industry. The NGPA has the further effect of restructuring the gas market by eliminating the division between interstate and intrastate gas for gas entering the market after its enactment.

The Congress intended to limit the authority of the Federal Energy Regulatory Commission to review whether the price paid for gas purchased by an interstate pipeline is just and reasonable. It did so

by having the NGPA provide that as long as the price paid by the interstate pipeline did not exceed the applicable lawful price under the NGPA, the amount paid is deemed to be just and reasonable. The Congress also intended that in most cases the interstate pipelines be allowed to pass along to their customers this "just and reasonable" price. However, the Congress did not intend this should occur if the price paid for purchased gas was excessive due to fraud, abuse, or similar grounds, as determined by the FERC.

When the NGPA was enacted, the pipelines faced a severe gas shortage. In order to alleviate the shortages, the pipelines entered into contracts with producers for new gas. The contractual arrangements entered into after the enactment of the NGPA together with the operation of the provisions of the NGPA caused some of the current controversy in the gas industry. The next section of this chapter contains an overview of how the NGPA provides for a phased, partial decontrol of gas wellhead prices, and the following section describes some of the controversies that surround contract provisions and other features of the gas market.

The NGPA: Phased, Partial Decontrol

The provisions of the NGPA that provide for a phased, partial decontrol of gas are widely considered to be quite complex. Even some supporters of the NGPA consider its provisions to be byzantine. There is no agreement about the number of categories of gas specified in the NGPA. However, for the purposes of this overview, the twenty-odd categories of gas have been combined into four major groupings. These major categories are old gas, defined in sections 104, 105, and 106 of the NGPA; new gas, defined in sections 102 and 103; high-cost gas, also known as section 107 gas; and stripper well gas and other gas, defined in sections 108 and 109, respectively. Table 2-1 and the discussion that follows summarize how phased, partial decontrol is to

TABLE 2-1

NATURAL GAS PRICE DEREGULATION UNDER THE NGPA

Natural Gas Prices Presently Deregulated	Natural Gas Prices To Be Deregulated on January 1, 1985 or July 1, 1987	Natural Gas Prices Subject To Continued Regulation
<u>Section 107(c)(1-4)</u> High-Cost Natural Gas from (i) Deep Wells (ii) Devonian Shale (iii) Geopressurized Brine (iv) Coal Seams	<u>Section 102(c)</u> New Natural Gas (Jan. 1, 1985) <u>Section 103</u> New Onshore Production Natural Gas Not Dedicated to Interstate Commerce before April 21, 1977 and from Wells (i) > 5000' (Jan. 1, 1985) (ii) < 5000' (July 1, 1987)	<u>Section 102(d)</u> New Natural Gas from OCS Reservoirs Discovered after July 26, 1976
	<u>Section 105</u> Intrastate Gas Not Subject to an Indefinite Price Escalator Clause and with a Price > \$1.00 per Million Btu on Dec. 31, 1984 (Jan. 1, 1985)	<u>Section 103</u> New Onshore Production Natural Gas Dedicated to Interstate Commerce before April 21, 1977
	<u>Section 106(b)</u> Intrastate Rollover Gas with a Price > \$1.00 per Million Btu on Dec. 31, 1984 (Jan. 1, 1985)	<u>Section 104</u> Old, interstate gas <u>Section 105</u> Intrastate Gas with a Price < \$1.00 per Million Btu on Dec. 31, 1984 or with a Price > \$1.00 per Million Btu on that Date under an Indefinite Price Escalator Clause
		<u>Section 106(a)</u> Interstate Rollover Gas
		<u>Section 106(b)</u> Intrastate Rollover Gas with a Price < \$1.00 per Million Btu on Dec. 31, 1984
		<u>Section 107(c)(5)</u> Incentive Priced High-Cost Natural Gas
		<u>Section 108</u> Stripper Well Gas
		<u>Section 109</u> Other Gas

Source: Authors' reading of the NGPA

be implemented under the NGPA for each of the major groupings of gas. A more detailed discussion of the provisions of the NGPA important to state regulators, including the various categories of gas, is contained in appendix C.

Old Gas

Gas defined in sections 104, 105, and 106 of the NGPA is generally called old gas. Section 104 old gas is gas that was dedicated to interstate commerce before the enactment of the NGPA with rates previously set by the FPC or the FERC. Section 104 old gas is also referred to as old interstate gas. Old interstate gas is generally the lowest priced of all categories of gas under the NGPA. The ceiling price of old interstate gas is increased each month by a factor known as the monthly equivalent of the annual inflation adjustment factor, which, for old interstate gas, is set so as to reflect the rate of inflation. As shown in table 2-1, the wellhead price for old interstate gas will never be deregulated under the NGPA.

Another category of old gas, defined by section 105 of the NGPA, is that sold under an existing, or any successor to an existing, intrastate contract that was entered into before November 9, 1978, the date of enactment of the NGPA. Old intrastate gas tends to have a higher price than old interstate gas. As shown in table 2-1, a portion of old intrastate gas will be deregulated on January 1, 1985. The old intrastate gas subject to continued regulation after this date is that which will have a price less than or equal to \$1.00 per million Btu on December 31, 1984, or that will have both a price greater than \$1.00 per million Btu on that date and an indefinite price escalator clause in the old intrastate gas contract. Otherwise, old intrastate gas with a price greater than \$1.00 per million Btu on December 31, 1984 will be deregulated on January 1, 1985. Most of the old intrastate gas is expected to have a price greater than \$1.00 per

million Btu on December 31, 1984, and, in the absence of these escalator clauses, will be deregulated on January 1, 1985.

The third category of old gas is defined by section 106 of the NGPA. This gas is generally known as rollover contract gas. Rollover contract gas is gas that was covered on November 8, 1978 (the day before the enactment of the NGPA) by an intrastate or interstate contract that later expired according to its own terms. As shown in table 2-1, intrastate rollover contract gas with a price greater than \$1.00 per million Btu on December 31, 1984 will be deregulated on January 1, 1985. Nearly all intrastate rollover gas will have a price greater than \$1.00 per million Btu and will therefore be deregulated on January 1, 1985, while all the old interstate and the interstate rollover contract gas will be subject to continued regulation.

Thus, some interstate pipelines might have a greater quantity of old gas subject to continued regulation than other pipelines after January 1, 1985. Those interstate pipelines might then have a larger cushion of cheap gas, which could be used to bid for new, more expensive gas after 1985. Pipelines having a larger proportion of deregulated old gas might have difficulty competing for new, more expensive supplies.

New Gas

Gas defined in sections 102 and 103 is usually called new gas. Generally speaking, gas from new wells is new gas. New wells, described more fully in appendix C, are generally those drilled after February 19, 1977. In addition, new section 102 gas includes certain gas from outer continental shelf (OCS) leases. The difference between section 102 new gas and section 103 new gas depends on the distance of the new well from the nearest existing well, called a marker well, and the completion location of the new well; this difference is further

discussed in appendix C, and the term, marker well, is defined in appendix A. Generally, it is easier for gas to qualify as section 103 new gas than it is to qualify as section 102 new gas.

The price of new gas is usually much higher than the price of old gas. The ceiling price of new gas is adjusted each month by an annual inflation adjustment factor. However, the section 102 new gas is adjusted also by a growth factor, which presently provides that its ceiling price be adjusted at an annual rate of 4%, in addition to the inflation adjustment.

As shown in table 2-1, most new gas will be deregulated on January 1, 1985. However, section 103 new gas that is produced from wells with a depth of 5,000 feet or less will be deregulated on July 1, 1987. Also, any section 103 new gas that was dedicated to interstate commerce before April 21, 1977 and any new gas produced from outer continental shelf reservoirs discovered after July 26, 1976 will never be deregulated under the NGPA.

High-Cost Gas

High-cost gas is defined in section 107. There are basically two categories of high-cost gas. The first category covers gas that has been deregulated from wellhead price controls. As shown in table 2-1, this includes deep gas, that is, gas from new wells with a production depth of 15,000 feet or more. It also includes gas produced from geopressurized brine, occluded natural gas from coal seams, and gas produced from Devonian shales. Typically, this deregulated high-cost gas is the highest priced of all categories of gas, and because of the guaranteed pass-through provisions of the NGPA, the most controversial.

There is a second category of high-cost gas that has not yet been deregulated. This category of gas is commonly called "section

107(c)(5) gas," or "incentive-priced high-cost gas." This is any gas produced under conditions that the FERC determines present "extraordinary risks or costs." The NGPA requires the FERC to prescribe whatever special price is necessary to provide reasonable incentives for the production of this gas. Thus far, only two types of gas have been designated to be incentive-priced high-cost gas. These are gas from tight formations, often called "tight sands gas," and qualified production enhancement gas. The FERC is considering adding two types of gas to this category: gas produced from deep water¹ and gas produced from depths between 10,000 and 15,000 feet, also known as "intermediate deep gas."² The ceiling price for section 107(c)(5) high-cost gas is set at 200 percent of ceiling price of section 103 new gas. While there is no provision in the NGPA for the deregulation of incentive-priced high-cost gas, most of the gas also qualifies as new gas and therefore will be deregulated in 1985 or 1987.

Gas From Stripper Wells and Other Categories of Gas

Two other, relatively minor categories of gas, are defined in sections 108 and 109 of the NGPA. They are commonly called "stripper well gas" and "other gas," respectively. Stripper well gas includes gas that is produced neither in association with crude oil nor at an average rate greater than 60,000 cubic feet per day over a 90-day period. If the production from a stripper well increases due to a recognized enhanced recovery technique, the gas can still qualify as stripper well gas. As shown in table 2-1, stripper well gas will not be deregulated under the NGPA.

¹45 Fed. Reg. 47863 (1980), FERC Docket No. Rm. 80-36.

²47 Fed. Reg. 638 (1982), FERC Docket No. 82-8.

"Other gas" is gas that does not belong to any of the other categories of gas defined in the NGPA. It includes the Alaskan gas produced from Prudhoe Bay and transported through the Alaskan Natural Gas Transportation System.

The Ensuing Controversies

As noted above, the NGPA provides for the gradual escalation of gas wellhead prices. Since its enactment, an escalation of gas wellhead prices has in fact occurred. But, price increases at the burner tip have not been gradual. During 1982, for example, average retail gas prices nationwide increased 25 percent, with increases more than double that in some regions, and these increases produced storms of protest around the nation.³ While a portion of the increases at the burner tip can be traced back to the inflation adjustment factors in the NGPA, there is disagreement concerning the reason for the rapid increase in gas burner-tip prices. Some analysts cite provisions in the producer-pipeline contracts as being an associated cause of the recent increase in gas prices. Other analysts contend that prices would have risen in any case.

Several of the other controversies that have ensued since the enactment of the NGPA are discussed in this section. The controversies include the debate over the NGPA attempt to achieve oil parity, the American Gas Association's contention on gas contract fly-up, conflicting opinions on pipeline motivation to engage in hard bargaining with producers, and the debate over take-or-pay contract clauses. Most of these issues are related to provisions in producer-pipeline contracts. Statistical information on the use of various such provisions is presented in appendix D.

³See, for example, "Natural Gas: A Winter of Discontent," New York Times, 6 February 1983, p. F1.

Oil Parity and Fuel Switching

As enacted, the NGPA provides for a gradual escalation of gas ceiling prices in order to allow the price of new gas to move gradually up to a rough parity with world oil prices. To phase in partial deregulation, the NGPA pricing schedules were keyed to the \$15 per barrel world oil price prevailing in 1978, with adjustments for inflation. Because the gas pricing scheduled was keyed to the prevailing price of oil in 1978, when oil prices increased at a rate higher than inflation, some analysts feared that there would be an oil-parity fly-up upon decontrol of new gas in 1985. However, in 1982-83 oil prices have dropped, creating a debate about whether fly-up will actually occur.

The price of residual fuel oil, which is the grade of oil that competes with gas for use in large boilers, has gone below the burner-tip price of gas in some areas of the country. As a result, some industrial customers that have alternate fuel capabilities have switched to residual fuel oil. As these industrial customers leave the gas system, the affected pipelines and distribution companies are left with fewer units over which to spread the fixed costs of the system, in some cases causing the remaining customers to face higher rates. Thus, oil parity--whether achieved with or without a 1985 fly-up in gas prices--creates difficulties for the gas industry.

The Gas Contract Fly-Up

Analysts at the American Gas Association (AGA) have argued that the producer-pipeline contractual arrangements as now written will cause a wellhead price fly-up in 1985 that could result in a further escalation of gas burner-tip prices and cause a further loss of load. The argument goes like this. Most of the gas that is now deregulated, or that is subject to deregulation in 1985 or 1987, is sold under contracts containing deregulation provisions, that is, provisions that

take effect upon deregulation. The most common type of deregulation provision is the three-party most favored nation clause, which sets the contract price as the highest price allowed in any other contract in the area, i.e., a contract involving a "third-party." A three-party most favored nation clause is considered dangerous by the AGA because it can be "triggered" by the highest price in a contract between any pipeline and any producer in a specified geographic location. Three-party most favored nation clauses, when triggered, can cause a sudden spread (or contagion) of the highest price throughout an area.

The trigger could be oil parity redetermination clauses. Much of the gas that is presently deregulated or that will be deregulated in 1985 and 1987 is sold under contracts containing oil parity redetermination clauses. Some of these clauses are tied to the price of number 2 fuel oil. Because a few of the contracts with oil parity clauses lack any type of buyer protection clauses such as market-out, regulatory disallowance, or maximum price clauses, the AGA argues that the contract price of gas could fly-up to the price of number 2 fuel oil. Because these contracts are widespread,⁴ they will tend to trigger every gas contract with a most favored nation clause. Only gas sold under contracts either without any deregulation clause or with a buyer protection clause will avoid the fly-up, unless all the oil parity contracts and three-party most favored nation clauses are renegotiated by the producers and the pipelines or somehow abrogated by the federal government. The data on producer-pipeline contractual arrangements presented in appendix D are not inconsistent with this argument.

⁴See Energy Information Administration, U.S. Department of Energy, Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market, An Analysis of the Natural Gas Policy Act and Several Alternatives, Part II, DOE/EIA-0330, prepared by Decision Analysis Corporation (Washington, D.C.: 1982), p. 50. According to this report, contracts with oil parity clauses and no market-out provisions can be found in contracts entered into by the five largest pipelines.

Other analysts contend that the controversy surrounding gas contract fly-up is overblown. Some contend that as the producers and the pipelines find that renegotiating these contract clauses is in their mutual interest, there will be no fly-up, and therefore nothing needs to be done. Other analysts contend that if a producer-pipeline gas contract fails to reflect the market, then the pipeline should "walk away" from the contract. These analysts have suggested that the pipelines can claim either force majeure, an inability to perform, or unforeseeable changed circumstance as a defense of their breach of contract should they find themselves in court.⁵

Conflicting Opinions on Pipeline Motivation to Engage in Hard Bargaining

Another controversy that exists concerns conflicting opinions on whether pipelines have been provided with a sufficient incentive to engage in hard contract bargaining under the NGPA.

Some analysts contend that the effect of guaranteed pass-through, especially as interpreted by the FERC, may have been to obviate any incentive that a pipeline would have had to negotiate hard for contracts with prices well below the NGPA ceiling price and adequate buyer protection provisions.⁶ Guaranteed pass-through differs from the pass-through allowed under the Natural Gas Act of 1938 in that the Natural Gas Act allowed producer price increases to be denied by the

⁵See Arlon Tussing and Connie Barlow, "The Rise and Fall of Regulation in the Gas Industry," Public Utilities Fortnightly, March 4, 1982, pp. 15-23.

⁶See generally Edward Falk, "Indefinite Price Escalation and Minimum Take-or-Pay Clauses: The Villians in the Piece," Public Utilities Fortnightly, October 28, 1982, pp. 56-59; and the Presiding Administrative Law Judge's Initial Decision on the Columbia Gas Transmission Corporation's Purchase Gas Adjustment Filings, Dockets TA81-1-21-001 and TA81-2-21-001 (1982).

Federal Energy Regulatory Commission if the producer (or pipeline) failed to sustain its burden of proving that the proposed increase was "just and reasonable." Under the then current U.S. Supreme Court cases, rates before the NGPA were sustained as being just and reasonable based primarily on cost-of-service based calculations.⁷ Guaranteed pass-through under the NGPA provides for the automatic pass-through of any price for gas if it does not exceed the applicable NGPA ceiling price, if any, unless the FERC determines that the amount paid was excessive due to fraud, abuse, or similar grounds.⁸ Because any price at or below the NGPA ceiling price will in most cases be guaranteed automatic pass-through, the NGPA ceiling price often becomes the actual contract price for gas from new wells, especially if the ceiling price is below the perceived market clearing price of gas.

Also, the tendency for the price of gas from new wells to track the published NGPA ceiling price is reinforced for pipeline systems with affiliated producers by the "affiliated entities limitation" contained in section 601 (b)(1)(E) of the NGPA. The affiliated entities limitation provides that any first sale between any interstate pipeline and its affiliated producer will be deemed just and reasonable if the price does not exceed the applicable NGPA ceiling price and if it does not exceed the price in comparable sales to non-affiliates. The affiliated entities limitation could create an incentive to pay non-affiliated producers the ceiling price provided under the NGPA so that the pipeline can pay its own affiliated producers the same maximum lawful price. This could cause difficulty if the ceiling price rises above the market clearing price.

It is also contended that what little incentive the guaranteed pass-through provisions of the NGPA might have provided interstate

⁷See Permian Basin Area Rate Cases, 390 U.S. 747 (1968); and FPC v. Hope Natural Gas Co. 320 U.S. 591 (1944). See also 47 Fed. Reg. 19157, 19167 (1982).

⁸See the NGPA section 601(b) and (c).

pipelines to engage in tough negotiations with producers was further diminished by a FERC policy statement that has the effect of limiting the "fraud, abuse, or similar grounds" standard to a consideration of whether the amount paid at the first sale was excessive as a result of misrepresentation or concealment. The FERC statement of policy might be viewed as opening the door for pipelines and producers to engage in a pattern of collusive behavior to "jack-up" wellhead prices so that a pipeline's affiliated producer might realize profits; or at the very least, the policy statement may lessen the pipeline's incentive to bargain hard in fulfilling its obligation to obtain gas "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest."⁹

Other analysts contend that the price of gas from new wells tracks the published NGPA ceiling price only because the market clearing price of gas is above the ceiling price. As long as this is so, the producer and the pipeline will find it mutually advantageous to negotiate a contract price for gas at the ceiling price. These same analysts contend that a pipeline's transactions with affiliated producers are simply following the same tendency to track the ceiling price. Finally, some analysts would contend that the source of any lack of incentive on the part of a pipeline to engage in hard bargaining can be found in the entire "cost-plus" system of regulation and not the automatic pass-through provisions of the NGPA.

The Take-or-Pay Provision Controversy

In the early 1980s, demand for gas decreased. The fall in demand is attributable to the recession, increased conservation, and fuel switching by industrial customers; and these effects are, in part,

⁹See *Atlantic Refining Co. v. Public Service Commission of New York*, 360 U.S. 378,388 (1959) for an example of this line of cases.

induced by a rise in the real price of gas. As demand has fallen, pipelines have attempted to cut back on their purchases of gas. However, many pipelines have not cut back first on purchases of the most expensive gas because of take-or-pay clauses in the producer-pipeline contracts. Such a clause requires a pipeline to pay the producer for a specified percentage of the gas under contract regardless of whether the gas is actually taken by the pipeline. As shown in appendix D, many of the contracts for the more expensive categories of new gas have take-or-pay requirements in excess of 80 or 90 percent. Take-or-pay requirements in some contracts for old gas, especially intrastate gas, are typically less. Furthermore, many of the producer-pipeline contracts for new and high-cost gas do not contain market-out clauses or other buyer protection clauses. Some pipelines then find themselves in a situation where they must either take or make prepayments for expensive gas that they cannot sell. In order to minimize their losses in the face of declining demand, pipelines sometimes cut back on purchases of low cost gas with a low take-or-pay requirement instead of the more expensive gas with a high required take. In particular, pipelines serving a producing state that meets some portion of its own gas needs may shut in low cost intrastate gas in order to honor contracts to take more expensive gas from another state. Some analysts contend that producer-pipeline contracts should be altered by either the FERC or the Congress to forbid less expensive gas being shut in while more expensive gas is being purchased. Others contend that the pipelines should breach such contracts.¹⁰

Much of the ensuing controversy about the NGPA can be traced back to the dominant feature of today's natural gas market, which is that the wellhead prices are only partially regulated. The industry is in transition from having wellhead prices fully regulated to having them

¹⁰Tussing and Barlow, op. cit.

mostly deregulated. In this environment, traditional cost-of-service regulation cannot operate, and normal market forces are not allowed to operate either. Both short-term problems and long-term difficulties contribute to a market that is in disarray. The next chapter contains an analysis of the distortions in the natural gas market that have resulted from the provisions of the NGPA, from the contract provisions agreed to by the producers and the pipelines, and from other causes.

CHAPTER 3

DISTORTIONS IN THE NATURAL GAS MARKET

Despite the NGPA plan of phased, partial deregulation, the natural gas market is still highly regulated. As we have seen, the Natural Gas Policy Act establishes wellhead ceiling prices for more than 20 categories of gas. While the Federal Energy Regulatory Commission still has some limited responsibility for the just and reasonable price regulation of old, flowing gas, its main role is the regulation of interstate pipelines as public utilities. And, of course, local gas distributors are regulated by state public utility commissions. This regulation of the industry as well as its organization has been cited by many observers as preventing the natural gas market from operating like a competitive market. In this chapter, the important market distortions, sometimes referred to as market ordering problems, that have been widely reported are discussed. The first section is organized to include those problems that prevent good short-run performance of the gas market or what might be termed operating as an efficient spot market. These issues are currently quite important and often constitute the entirety of what some observers mean by market ordering problems. There are other, long-term issues, however, that state commissions should be aware of, and these have been collected in the second section.

Current Market Problems

The 1982-1983 recession reduced the demand for natural gas. This occurred at a time when the natural gas market was adjusting to recent, far-reaching changes in the way wellhead prices are regulated and to an increase in world oil prices that was unforeseen in 1978 when the NGPA was passed. Unfortunately, at precisely the time when substantial changes in both supply and demand were occurring, the industry was subjected to price regulation that prevented price from

adjusting and alleviating the resulting economic pressures. Prior to 1978 and the NGPA, adjustments in the unregulated intrastate market served to partially offset changing national market conditions. The NGPA eliminated this safety valve and also somewhat reduced FERC discretion in setting just and reasonable rates, both of which have the effect of reducing price flexibility. Any economic pressures from imbalances of supply and demand can be relieved either by changing the regulations or by adjustments in nonprice aspects of natural gas contracts. In any case, most of the current or spot market problems identified by observers of this industry are related to the price rigidity imposed by the NGPA at a time when flexibility would have been a virtue.

Prespecified NGPA Price Trajectories

The NGPA established prespecified paths for increases in the ceiling price of new gas. These price paths were intended to bring the price of new gas up to its market clearing level just prior to deregulation of new gas in 1985, thus smoothing the transition from a price controlled to a deregulated market for new natural gas. The 1985 target price set by the Congress was based upon oil selling for \$15 per barrel. The NGPA, however, sets the gas ceiling price in terms of dollars per mcf and does not allow flexibility when other energy prices, such as oil, change. The NGPA moving ceiling price is adjusted upward each month so as to produce an annual real (i.e., inflation adjusted) increase in the price of section 102 gas of 3.5 percent through April 1981 and 4 percent thereafter.

In the late 1970s, the price of crude oil had increased in real terms much more rapidly than the 3.5 to 4 percent annual real rate of increase permitted for new gas. This produced widespread concern that the deregulation of new gas in 1985 would result in an extreme price increase as new gas prices rose to levels compatible with the prices of alternate fuels.

In the early 1980s, price weakness in world oil markets has produced a decline in real oil prices while the price of new gas continues to move upward at an annual rate of 4 percent in real terms. After falling behind the price of fuel oil throughout the seventies, the regulated price of new gas is moving toward parity with fuel oil. This rise in the regulated price of gas relative to fuel oil prices has generated concern among gas distribution companies that some of their industrial customers may switch to fuel oil, raising the portion of fixed costs to be borne by the remaining customers.

The NGPA method for adjusting the ceiling prices for new gas simply does not respond to changing conditions in the energy market. The use of a general price index to adjust these prices means that the adjustment reflects changes in the general price level of all goods and services, of which energy prices are merely one component. By 1985, the NGPA ceiling price for new gas will only by chance be close to the deregulated market clearing price of gas.

1985 Natural Gas Price Fly-up

Several scenarios for natural gas prices in 1985 include predictions of a fly-up in natural gas prices. Fly-up refers to the rapid rise in natural gas prices expected in 1985 when ceiling prices for new gas are removed. The term, fly-up, also refers to situations in which 1985 natural gas prices are thrust above levels that would occur in a fully deregulated market.

One version of the 1985 natural gas price fly-up predicts a sharp rise in natural gas prices as the price of newly deregulated gas moves into price parity with fuel oil.¹ The NGPA's moving ceiling prices

¹See the Federal Energy Regulatory Commission, Notice of Inquiry, "Impact of the NGPA on Current and Projected Natural Gas Markets," 47 Fed. Reg. 19157-65 (1982).

were intended to smooth the transition from regulated to deregulated pricing. However, the scheduled increases in these ceiling prices are based on inaccurate estimates of 1985 oil prices. Thus, in 1985 natural gas prices could soar upward if the NGPA ceiling price is too low. Recent weakness in world oil prices makes it unclear to what extent the regulated price of new gas will miss its target of price parity with oil in 1985.

A second version of natural gas price fly-up in 1985 is based on the view that the cushion of old gas remaining under control in 1985 will subsidize the purchase of deregulated gas. Thus, the price of new gas in 1985 may be pushed above the level that would occur if all gas were deregulated. This market ordering problem stems from the price controls remaining on old gas after 1985, which tend to distort the pricing and consumption of all gas. A more detailed analysis of this phenomenon is presented later in this chapter when examining the rolled-in pricing of various vintages of gas.

A third type of fly-up refers to a rise in gas prices above the free market level caused by the operation of certain indefinite price escalators in 1985.² This is one of a variety of contract clauses, discussed in chapter 2, pertaining to the determination of gas prices when they are deregulated. Some indefinite price escalator clauses provide for a renegotiation of the price in the future, and others known as redetermination clauses, require a prespecified adjustment of gas contract prices based on the highest prices paid to other producers (i.e., a most favored nation clause) or on the price of number 2 distillate fuel oil. A 1985 jump in the price of some natural gas which is tied by redetermination clauses to the price of fuel oil may trigger a similar rise in the price paid under contracts with most favored nation provisions.

²American Gas Association, "Consumer Impact of Indefinite Gas Price Escalator Clauses Under Alternative Decontrol Plans," Energy Analysis (Washington, D.C.: November 6, 1981), p. 1.

One forecast of gas prices in 1985 estimated that gas wellhead prices would rise by 51 percent in real terms if all escalator clauses remain in effect. Should indefinite price escalator clauses not be allowed to take effect, only a 7 percent rise in 1985 was predicted for natural gas prices in real terms.³

The existing buyer protection clauses may allow pipelines to refuse to purchase gas that is unmarketable (i.e., market-out clauses). Other buyer protection clauses may set a maximum price on gas or permit the contract price to be reduced if the FERC disallows a change in the price. Buyer protection clauses, while not prevalent in contracts covering gas supplies, are an increasingly common feature of new natural gas contracts, however.⁴

The market ordering problems associated with price escalators are largely due to the inflexibility associated with most favored nation and oil parity pricing clauses. An oil parity clause makes sense only if there is a technological stability in the substitution of fuel oil for natural gas. If the substitution relationship between natural gas and fuel oil changes over time or is estimated inaccurately, an oil parity clause will not correctly redetermine the market price of gas. Oil parity clauses that overestimate the market value of gas may then trigger the most favored nation provisions in other gas contracts. These problems could be avoided if the indefinite price escalator calls for a periodic renegotiation of the price instead of an automatic adjustment.

³Ibid., p. 2.

⁴Energy Information Administration, U.S. Department of Energy, The Current State of the Natural Gas Market, DOE/EIA-0313. (Washington, D.C.: December 1981), p. 80; and Energy Information Administration, U.S. Department of Energy, Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market, DOE/EIA-0330 (Washington, D.C.: June 1982), pp. 27-33.

Contract Clauses in Producer-Pipeline Transactions

The contractual arrangements between natural gas producers and pipelines are crucial in understanding the impact that rising wellhead prices for natural gas will have on gas customers. Two of the most important contract clauses found in producer-pipeline contracts are take-or-pay clauses and indefinite price escalators.

Take-or-Pay Clauses

Take-or-pay clauses are a very common feature of producer-pipeline contracts. A take-or-pay contract requires that a gas pipeline company purchase a specified percentage of the annual gas volume covered by the contract. Such purchases must be made whether or not the gas is needed by the pipeline to meet the demand of its customers. Thus, a pipeline may not simply turn to less expensive sources of supply if the wellhead price of gas falls, since it has contractual obligations to purchase a fixed amount from its current suppliers.

The take-or-pay arrangements that developed in the natural gas industry serve several functions. The minimum price and volume requirements of take-or-pay clauses protect producers, to some extent, from the monopsony (i.e., single buyer) power of the pipelines. Such clauses may, for example, prevent the producer from being shut in. Take-or-pay clauses also provide producers with valuable protection against the risk of reduced demand for natural gas, since gas is often produced in conjunction with oil and may be wasted if not sold. In addition, when two or more producers draw gas from the same field, a producer who cannot sell his portion of the field's daily output will have his share of the field's gas reserves depleted. In general, a take-or-pay agreement alleviates the producer's risk in being committed to a single pipeline, thereby allowing the pipeline to secure long-term supplies.

Under normal circumstances, take-or-pay clauses are constructive and serve the important functions described above. Recently, however, an unfortunate combination of events involving them has produced serious distortions in the mix of gas being sold by pipelines. The unforeseen rise in oil prices after the 1978 passage of the NGPA undoubtedly raised the market clearing price of natural gas. The NGPA ceiling prices prevented gas prices from rising, however. Take-or-pay clauses can be an important nonprice feature of producer-pipeline contracts that can be used to compensate producers when prices cannot be increased, as described below in some detail. Consequently, many new contracts for new gas (more expensive than old gas) contained high take-or-pay provisions. Subsequently, the 1982 economic recession reduced the demand for gas.

Pipelines reduced their takes on all vintages of gas. The reduction in new gas takes, however, was limited by the recently negotiated high take-or-pay fractions. The result was sometimes the reduction of production from old, inexpensive wells while maintaining high production rates from more expensive, newer wells. The socially efficient gas mix would be obtained by first reducing production from the most expensive sources to the lowest practical level, possibly zero. The distortion in this case is that consumers are paying an excessively high price for gas in the short run because of the combined effects of low demand and an unfortunate set of take-or-pay contracts.

While the risk sharing and producer aspects of take-or-pay contract provisions have been recognized for some time, the implicit financial compensation involved in take-or-pay arrangements has been largely ignored. The financial benefits conferred on natural gas producers by take-or-pay clauses are clear. When a gas purchase contract contains a take-or-pay provision and a price renegotiation clause with a specified minimum price, any increase in the market price of gas above the contract's minimum price will cause the higher

market determined price to be paid to producers. If the market price of gas declines below the contract's base price, the pipeline is obligated to pay for a specified percentage of the contract's annual gas volume at the contract's base price. In some contracts, the price in the period immediately preceding the exercise of the take-or-pay provision is used as the price to be paid.

The pipeline company could virtually duplicate the financial implications of a take-or-pay contract by selling what is known as European put options on the proportion of gas covered by the take-or-pay provisions. Some insights into the workings of the U.S. natural gas market can be obtained by exploring this analogy in some detail. The purchaser of a European put has the right to sell an asset such as gas at a specified price at a specified future date. A take-or-pay contract implicitly contains put options allowing the natural gas producer to sell gas at a prespecified price during each year that the contract is in force. For example, if in the seventh year of the contract the market price of gas is \$3.50 per mcf⁵ and the contract's base price is \$4.00 per mcf, the producer will exercise his put option allowing him to sell gas to the pipeline at the contract's base price giving the put a final value of 50 cents per mcf. If the market price of gas in the seventh year is above the minimum price set in the contract, the put option will be worthless.

The full price implicitly paid by a pipeline for new gas includes the contract price plus the current value of the put options on the percentage volume of gas covered by take-or-pay provisions. A higher percentage of the gas volume covered by take-or-pay contracts gives the producer more put options on gas. Thus, the NGPA ceiling prices

⁵One thousand cubic feet of gas, denoted mcf, contains approximately one million British thermal units (Btu) depending on the energy content of the gas.

for new gas can be effectively circumvented by using high percentage take-or-pay provisions to provide producers with compensation in addition to paying the NGPA ceiling price.

The Black-Scholes option pricing model can be applied to estimate the current market value of the put options implicitly contained in take-or-pay provisions.⁶ The puts are financial assets with a future value contingent upon the uncertain future price of gas. The Black-Scholes model requires an estimate of the variance of the return on the commodity gas. For example, if the price of gas increases 15 percent in one year, then its rate of return is 15 percent that year. The variance of the return on gas measures the degree of variation of the actual return on gas around its mean or expected value. It is difficult to estimate the variance of the return on new gas, since under the NGPA the pre-1985 controlled price of new gas will be very stable while after decontrol in 1985 the price and hence the return on new gas should exhibit considerably greater fluctuations.

For purposes of illustration, assume that in 1985 and beyond the risk-free rate of return is 10 percent and variance of the rate of return on the wellhead price of gas is 9 percent, which implies a standard deviation of returns of 30 percent. Furthermore, assume that the 1982 market clearing price for new gas was \$4.00 per mcf. This price would not have been observed because of the NGPA ceiling price for new gas.

A take-or-pay contract for new gas written in 1982 might contain the following provisions. The producer is to supply one million mcf of gas to the pipeline each year for the next twenty years. Prior to 1985 the producer will receive the NGPA ceiling price for new gas. In

⁶Fischer Black and Myron Scholes, "The Pricing and Options and Corporate Liabilities," Journal of Political Economy 81 (May/June 1973): 637-53. For a review of the option pricing literature, see Clifford W. Smith, Jr., "Option Pricing," Journal of Financial Economics 3 (1976): 3-51.

1985 and all subsequent years, the producer will receive the prevailing market price paid for natural gas. If the market price happens to be below \$4.00 per mcf, the producer will receive a price of \$4.00 per mcf on 90 percent of the contracted annual gas volume. During each year that the contract is in force, the producer has a put option that allows him to sell 900 million cubic feet of gas at a price of \$4.00 per mcf.

Given the conditions described above, the value of the take-or-pay put options per mcf are given in the last column of table 3-1. The entries in the table are calculated using the Black-Scholes model. The meaning of the entries can be understood by considering, for example, the value of gas in 1990. If the put options on gas were traded in a competitive commodities option market, investors in 1982 would be willing to pay 20 cents for the right to sell one mcf of gas at a wellhead price of \$4.00 in 1990, since the variance of gas prices implies that there is a definite probability that the gas price will be below this level in 1990. Also, investors would be willing to pay \$2.40 in 1982 to gain the right to buy one mcf of gas at a price of \$4.00 in 1990. This is the value of European call option exercisable in 1990. A European call option is the right to buy an asset at a fixed price at a specified future date. The sum of the 1982 free market values of put options on one mcf of gas during all 18 years from 1985 to 2002 is \$2.75/mcf. Thus, the value of the bundle of put options contained in our hypothetical take-or-pay contract is about 2.475 million dollars (1 million mcf x 90 percent x 2.75).

Thus, take-or-pay provisions can be used by gas pipelines in effect to pay more for new gas than the NGPA specified ceiling price. In our illustration, producers are paid the ceiling price for natural gas in 1983 and 1984 but also receive put options, which are valuable financial assets that shield the producer against the possibility of a downturn in the price of gas. By varying the proportion of the total gas volume covered by take-or-pay provisions, the producer and

TABLE 3-1
 ESTIMATED WELLHEAD PRICES OF CALL AND PUT OPTIONS
 ON NATURAL GAS USING HYPOTHETICAL DATA

Year in Which Option May be Exercised	Estimated 1982 Market Value of a European Call Option on Gas (1982 \$/mcf)	Estimated 1982 Market Value of a European Put Option on Gas (1982 \$/mcf)
1985	1.34	0.31
1986	1.61	0.29
1987	1.84	0.27
1988	2.05	0.24
1989	2.23	0.22
1990	2.40	0.20
1991	2.55	0.18
1992	2.69	0.16
1993	2.81	0.14
1994	2.92	0.12
1995	3.02	0.11
1996	3.11	0.10
1997	3.20	0.09
1998	3.27	0.08
1999	3.34	0.07
2000	3.40	0.06
2001	3.46	0.06
2002	3.51	0.05
Total	48.75	2.75

Source: Authors' calculations based on hypothetical data.

pipeline can negotiate a market price effectively above the NGPA ceiling price.

One major disadvantage of the take-or-pay contractual arrangement is that it can distort the rates paid by consumers over time because if the price of gas should fall below the contract rate after 1985, the pipeline and its customers will be forced to honor put options that were used to secure new gas supplies in previous years when gas was subject to price controls. In effect, future gas consumers take on a risky financial liability to support pre-1985 purchases of new gas.

According to the Black-Scholes option pricing model, the value of put options on an asset such as gas is directly related to the expected volatility of the price of the asset. Prior to the enactment of the NGPA, the regulated price of natural gas was relatively stable. Thus, put options implicitly contained in take-or-pay agreements were of little value as a form of financial compensation to producers. The NGPA scheduled removal of ceiling prices for new gas will permit a much greater volatility in new gas prices after 1985. This greater expected price volatility in new natural gas prices has significantly increased the value of put options implicitly contained in take-or-pay agreements. Thus, the financial compensation aspect of take-or-pay contracts has grown in importance relative to their traditional function of limiting the risks borne by producers. Any policy analysis of modifications to take-or-pay contractual arrangements in the natural gas industry should consider the effect on the implicit price of gas and on the risk sharing arrangements between pipelines and producers.

Indefinite Price Escalator Clauses

Indefinite price escalator clauses are also a very common feature of producer-pipeline contracts. Older indefinite price escalator

clauses often provide that the pipelines receive a payment equal to the maximum rate permitted by the FERC. More recent indefinite price escalator clauses require the redetermination or renegotiation of the contract price in the event of a deregulation of natural gas prices.

An indefinite price escalator clause that simply allows gas producers to receive the current market price at the time of sale would, by itself, create no market ordering problems. However, if an indefinite price escalator clause redetermines the contract price based on oil prices, the resulting gas price may not accurately reflect actual conditions in the natural gas market. Escalator clauses that are designed to permit gas contract prices to follow the market price of gas will make the price of gas more responsive to current market conditions.

Fixed price contracts have virtually disappeared from the natural gas industry. An explanation for this shift in contractual arrangements is found by viewing the fixed price contract as implicitly offering options on gas. Just as in the case of take-or-pay contract clauses, the fixed price contract can be interpreted as a package of options. A fixed price contract for gas may be thought of as a combination of the sale of put options and the purchase of call options by the pipeline. When the current market value of the gas is below the fixed contract price, producers will exercise their put options to sell gas to the pipeline at the fixed price. When the current market value of gas rises above the fixed contract price, the pipeline would exercise its call option to buy gas at the fixed price.

Recalling the assumptions used in the preceding illustration, a fixed price contract requirement will entitle the gas pipeline to call options on post-1985 new gas with a market value of 48.75 million dollars (\$48.75 per mcf x 1 million mcf), as shown in table 3-1. The put options sold to the pipeline would be worth \$2.475 million (\$2.75

per mcf x 0.90 x 1,000,000 mcf), given that the pipeline is required to take 90 percent of the annual volume. In a free market the pipeline would be required to pay \$46.275 million up front in 1982 (i.e., \$48.75 million - \$2.475 million) to entice producers into a long-term fixed price contract for 1 million mcf per year at a price of \$4.00 per mcf.

Expected inflation and its effect on the expected rate of increase in the price of natural gas account for part of the prohibitive current cost of fixed price contracts. In addition, a very important factor is the expected increase in the volatility of new gas prices in a deregulated market. The more volatile are gas prices the more the value of a call option on gas increases. In the 1950s when natural gas prices were stable with no tangible prospect of deregulation, a call option that allowed the future purchase of gas at a fixed price was worth very little. Today the price volatility of deregulated deep gas and the prospective deregulation of new gas make the security provided by fixed cost contracts extremely expensive for pipelines.

Definite price escalators eliminate some of the uncertainty about future contract gas prices by prespecifying a series of successively higher prices to be paid for natural gas over the life of the contract. Thus, in evaluating the cost of a gas contract with a definite price escalator clause, the contract can be thought of as a series of future annual fixed price contracts. The net cost to the pipeline of entering into a definite price escalator contract is the value of the call options, which allow the pipeline to buy gas at the prespecified contract prices, less the value of the put options, which give producers the right to sell gas at the prespecified contract prices.

The higher the level of the prespecified contract prices, the lower is the initial cost to the pipeline of entering into a definite

price escalator arrangement. At a sufficiently high level of prespecified contract prices the pipeline would be entitled to receive an initial payment from the producers, since the producer's put options to sell gas at high future prices would be worth more than the pipeline's call options to buy gas at these prices. Thus, definite price escalator clauses can be used to circumvent the NGPA ceiling prices for new gas by offering producers sufficiently high prices on gas sold after the scheduled decontrol in 1985. Like take-or-pay arrangements, definite price escalators can be used to shift the cost of current new gas purchases into the future by granting producers favorable terms in the post-decontrol era.

Contract Clauses in Pipeline-Distributor Transactions

Three contractual arrangements commonly found in pipeline-distributor contracts are minimum bill requirements, purchased gas adjustment (PGA) clauses, and demand charge provisions. Each of these arrangements has important implications with regard to the NGPA's impact on the price paid at the burner tip.

A minimum bill requires a natural gas distribution company to buy a specified percentage of the annual volume for which it has contracted with the pipeline at the agreed upon price. Under minimum bill arrangements, the pipeline implicitly receives put options on gas from distribution companies.

The implicit put options granted to producers by pipelines through take-or-pay contracts are flowed through to gas distribution companies in the form of a minimum bill. A natural gas pipeline eliminates its own option risk by matching the put options on gas granted to producers with put options on gas received from gas distribution companies. The potential pipeline liability under the take-or-pay provisions with producers is simply offset by the minimum bill arrangement with distribution companies.

In times of natural gas shortages, distribution companies can bid for gas by paying the regulated city-gate price for gas and agreeing to a higher minimum bill, which grants valuable put options on gas to the pipeline. The pipeline can then "sweeten" the NGPA wellhead price of gas by granting to producers a package of put options on gas in the form of a higher take-or-pay provision.

In the pre-NGPA past, the regulated price of gas exhibited relatively little fluctuation and, hence, put options on natural gas had little value. The put option aspects of take-or-pay and minimum bill provisions were of little importance in the 1950s and 60s. The passage of the NGPA gave a new meaning to take-or-pay and minimum bill provisions, which became useful as a means of circumventing the NGPA ceiling prices in new natural gas contracts. The greater fluctuation of new gas prices in a post-1985 decontrolled market gives a much higher value to the put options on gas that are exercisable after 1985. Hence, the option to sell gas at a fixed price found in take-or-pay and minimum bill requirements has grown in importance as a form of compensation ultimately paid to producers.

Just as minimum bill requirements allow the put option risk from take-or-pay contracts to flow through to gas customers, the purchased gas adjustment clause allows any price fly-up to flow through to customers. It has been argued that PGAs weaken the pipelines' incentive to avoid higher cost gas and contracts with risky redetermination provisions by allowing increases in gas commodity costs to be quickly shifted to distribution companies and ultimate customers. As with other automatic adjustment clauses, the financial health of the utility is strengthened while the incentive to operate as a cost minimizer may be weakened.

The demand charge provisions found in pipeline-distributor contracts typically allow part of the pipeline's fixed costs to be included in the commodity charge (i.e., charge per mcf) and the

remainder is treated as a fixed demand charge to the gas distribution company. In its 1952 Atlantic Seaboard Corporation decision, the Federal Power Commission (FPC) issued opinion number 225 which established its policy on the allocation of fixed costs. The Seaboard decision required that 50 percent of the pipeline's fixed costs be collected through a commodity charge and the other fifty percent be treated as a demand charge.⁷ This approach was overturned by the 1973 United decision under which 75 percent of the pipeline's fixed costs are recovered through the commodity charge and only 25 percent are recovered using a demand charge.⁸ A simple volumetric approach, by comparison, would allocate all fixed costs to the commodity charge per mcf.

If the actual volume of gas sold is higher than expected, the fixed costs allocated to commodity charges will be overcollected until the commodity charge is adjusted downward to reflect the greater volume of sales. When the actual volume of gas sold is lower than anticipated, the fixed cost allocated to commodity charges will be undercollected until the commodity charge is raised to reflect the smaller sales volume over which fixed charges are being spread.

Since the prospect of rapidly rising natural gas prices promotes both the conservation of natural gas and the switch to alternative fuels, the lower volume of gas sales will, under the existing treatment of fixed costs, lead to even higher commodity charges as these fixed costs are spread over fewer units of sales. Hence, pipelines with the greatest excess capacity would tend to have the highest fixed charge components in their commodity rates.

⁷In the Matters of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, 11 FPC 43,56 (1952). For a brief summary, see Richard J. Pierce, Jr., Natural Gas Regulation Handbook (New York: Executive Enterprises Publications Co., Inc., 1980), pp. 86-7.

⁸United Gas Pipeline Company, 50 FPC 1348,1362 (1973).

A market ordering problem in this situation is caused by the average cost pricing of gas. In a competitive market with severe excess capacity, no fixed charge would be included in the price of the item. Unable to recover their fixed costs, competitive firms would continue to fail until the industry's excess capacity problem is eliminated. When a regulated industry is allowed to recover all of its fixed costs, its customers bear all the risk associated with excess capacity. The average cost pricing methods common in regulated industry place the full burden of excess capacity costs on the remaining customers, which further discourages consumption and aggravates the existing capacity utilization problem.

Long-Term Market Issues

The discussion in the previous section treats aspects of the natural gas market that prevent it from operating as an efficient spot market. This section is organized around another set of issues that could potentially create long-term market ordering problems if current circumstances were to continue indefinitely. The initial discussion of each of these problems describes the nature of the long-term distortions that might arise if the regulation and organization of the natural gas market remains unchanged. This long-term perspective is useful in understanding some fundamental characteristics of this market, even though the Natural Gas Policy Act will change the economic reality in only two years (1985). Following the discussion of these long-term market issues, some likely consequences of these matters under changing regulation are discussed.

Rolled-In Pricing According to Vintage

A transmission company normally buys gas in several different NGPA categories. The price that the transmission company's customers (distribution companies and some large industrial customers) pay is set by the Federal Energy Regulatory Commission so as to reflect the

pipeline's average acquisition cost. Consequently, final users pay an average of the various wellhead prices established by the NGPA plus the regulated transportation costs of the pipeline transmission company as well as that of the local distribution company. The result is an average of the prices of various vintages of gas and is commonly called rolled-in pricing.

This type of pricing scheme has evolved because of the political judgment by the U.S. Congress that it was and is important that consumers receive at least some portion of the economic rent, or pure excess profit, that would otherwise go to the owners of the natural gas wells if prices were unregulated. The implicit reasoning embodied in the NGPA is that while higher prices may be necessary to encourage new gas discoveries, allowing such higher prices to be paid also to the owners of previously discovered or old gas results only in the enrichment of producers at the expense of consumers. Hence, old gas prices are kept low in the NGPA, while new gas fetches a higher, regulated price and deep gas is totally unregulated.

It is undoubtedly true and widely understood that pure economic rents are transferred to producers as natural gas prices are allowed to rise. The fundamental cause is that additional supplies of natural gas can be found only at increasing marginal cost. Since a competitive, unregulated market clears where demand equals marginal cost, producers who have the good fortune to own supplies that are less expensive to develop than the marginal well will reap some pure economic rent. The same is also true of other producers, such as farmers: those who own particularly fertile pieces of land benefit because price is heavily influenced by the marginal, less fertile, and consequently more costly acres that are last called into production to fulfill demand.

What may not be as well understood, however, is that pure economic rents are a natural by-product of a competitive, increasing

cost industry.⁹ Virtually any attempt to regulate the rents affects the economic efficiency of the market. The natural gas market is no exception. Rolled-in pricing does reduce the transfer of pure profits to producers but at the expense of at least some misallocation of resources. What follows is a stylized description of the economic inefficiency induced by rolled-in pricing, even if all other aspects of the market were perfect. In particular, some resources are misallocated by this type of average pricing even if supply and demand were otherwise correctly ordered. Correct ordering of supply means that gas wells are brought into production in increasing order of marginal cost, and correct ordering of demand means that customers are served in decreasing order of their willingness to pay, as in a competitive market.

The discussion is facilitated by developing a concept of the equilibrium reached in a market that is subject to rolled-in pricing. Although the concept and its exposition have not been discussed before to the authors' knowledge, it seems likely that the Congress was intuitively aware that the NGPA might cause some resource misallocation. It is entirely possible that the inefficiency was a politically acceptable consequence of redistributing the economic rents, at least as it was implicitly estimated by the Congress at the time the NGPA was enacted. Hence, our initial focus on resource

⁹There are a few observers who claim that the production phase of the natural gas market is not competitive. These seem to be a small minority, however. Many observers seem to believe that the industry has the characteristics of competition--many producers (more than a thousand including independent wildcatters) frequently selling to two or more major pipelines. In addition, if collusion among these producers to set monopolistically high prices were the problem, it is unclear why the federal government would directly regulate price instead of using its antitrust powers. If, on the other hand, the monopsony power of a single pipeline were the difficulty, consumers would not need protection since such a pipeline would obtain low prices from producers. FERC regulation would eventually result in these low prices being passed on to consumers.

misallocation should not be interpreted by the reader to mean that we consider it to be the only important matter. Rather, it provides a way of understanding the nature of the market with rolled-in pricing and also a way to gain some perspective about the commentary of others.

One important way that natural gas wellhead price regulation was changed by the NGPA was to allow higher prices for gas that is more costly to produce. Prior to the NGPA, the major difference in gas prices was between interstate and intrastate markets. Low, regulated interstate prices resulted in the natural gas shortages and declining reserves of the 1970s (as discussed in appendix B). But, there was not typically a wide variation in the prices being rolled in. In contrast, the importance of rolled-in pricing has been increased dramatically by the 1978 NGPA. Rolled-in pricing now has consequences quite different from what it had under the previous policy of holding interstate prices low.

In particular, it is possible that the current method of implementing rolled-in pricing may result in an equilibrium with no shortages, that is, with supply equalling demand. Such an equilibrium could occur even if price regulation could be imposed perfectly, that is, even if each producer received exactly the marginal cost of his gas. It is instructive to discuss briefly this perfect version of a rolled-in pricing equilibrium because it helps in understanding several claims about rolled-in pricing that have appeared in the literature. In addition, it is frequently useful to cast an economic analysis using simplifying assumptions in the beginning, anticipating that these must be relaxed later to more accurately reflect reality. If every producer received only his own marginal cost, none would receive any economic rent or pure profit. The resulting equilibrium is illustrated in diagrams containing simple linear supply and demand curves.

A few basic concepts need to be reviewed briefly for those readers who may not be completely familiar with such diagrams. A competitive equilibrium is first illustrated in figure 3-1. The demand curve has a negative slope because more natural gas is demanded at lower prices. The supply curve slopes upward because the least expensive sources of gas are developed first. That is, the supply side of the market is assumed to be correctly ordered. The diagram shows the market for natural gas at the wellhead. Demand at the wellhead, as shown, can be found by subtracting transmission and distribution costs from demand at the burner tip.

If the market were competitive, the market price would be P_c in figure 3-1, and Q_c would be traded. The same price, P_c , would be paid by all consumers and received by all producers. Social welfare is traditionally measured as the sum of consumers' and producers' surpluses. Consumers' surplus is any willingness to pay, as measured

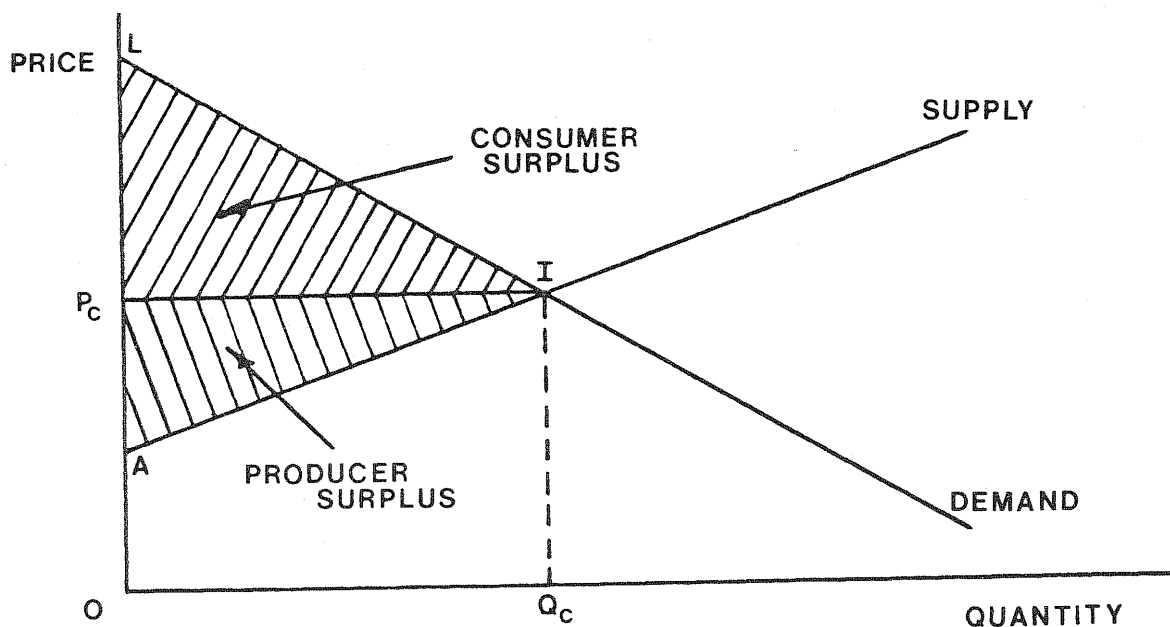


Fig. 3-1 A competitive equilibrium

by the demand curve, in excess of actual payments. Accordingly, in the diagram it is the area beneath the demand curve but above the price actually paid, or area $LP_C I$. Producers' surplus, sometimes called economic rent or excess profit, is any amount received by suppliers in excess of marginal cost. Since the supply curve is marginal cost, economic rent equalling area $P_C AI$ would accrue to gas well owners in a competitive market. The economic rent is due to the fact that a marginal gas well having a marginal cost of P_C is needed to clear the market. Since all producers are paid the same selling price, those with marginal cost less than P_C , due to easier accessibility of their gas source, receive a surplus in the sense that more is paid than is needed to induce such resources into production.

A rolled-in pricing equilibrium differs from the competitive one just described in that each producer receives only his own marginal cost, at least ideally. At any production level total payments to suppliers are less than the corresponding competitive amount. At the output level Q_C , for example, competition would result in revenues equal to the area $OP_C IQ_C$ being paid to suppliers. Perfect marginal cost pricing would yield total payments of a $OAIQ_C$ to producers. That is, the producers' surplus triangle $P_C AI$ no longer accrues to gas well owners.

A rolled-in pricing equilibrium, then, is one in which each supplier receives a different price, one equal to his own marginal cost. Consumers, on the other hand, pay the average of this constellation of producers' prices. For there to be an equilibrium with no shortages requires that two conditions be met. First, the last unit of gas demanded at the average price must be supplied by the most expensive producer. Second, the total payments by consumers must equal the total receipts of producers. Such an equilibrium is illustrated in figure 3-2. In that figure, the rolled-in price is

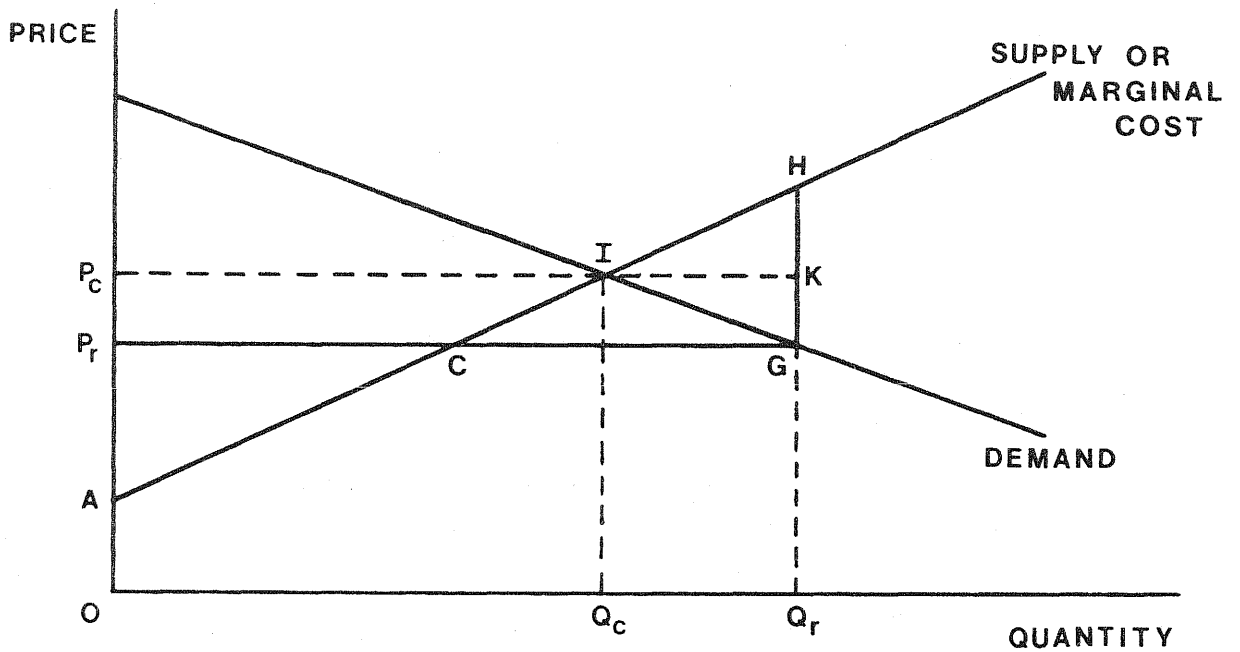


Fig. 3-2 A market equilibrium with rolled-in pricing

P_r and at this price consumers demand the quantity Q_r at point G on the demand curve. Consequently, consumers pay an amount equal to area OP_rGQ_r for natural gas. Producers receive revenues equal to the area under the supply curve, or $OAHQ_r$. An equilibrium, then, requires that area OP_rGQ_r equal area $OAHQ_r$.

Several characteristics of this equilibrium are worthy of note. Except for the rolled-in pricing, the market is correctly ordered, but resources are misallocated. In figure 3-2, the last production well has a marginal cost equal to the vertical distance Q_rH . Since supply and demand are well ordered, this most expensive well serves the last user who, from the demand curve, values the service at the vertical distance Q_rG . Hence, resources are being devoted to an activity with a marginal cost that exceeds the consumers' willingness

to pay. In this example, this waste equals the vertical distance HG. Indeed, all units that are consumed beyond the competitive intersection of supply and demand (at point I) have been produced at a greater marginal expense than the value attached to them by consumers. Hence, the total value of the resource misallocation from an otherwise perfect policy of rolled-in pricing is the triangle IHG representing the unit-by-unit social cost in excess of the consumers' value.

A second characteristic is that some expensive gas is produced. For example, rolled-in pricing calls forth production along the supply curve from point I to H in figure 3-2, which is inefficient because this production would not be used in a competitive market. The competitive equilibrium at point I allows no production beyond Q_C . Hence, it is not surprising that deep gas from more than 15,000 feet is produced with a rolled-in pricing policy, and most likely this would not be economical if all producers received and consumers paid the same price P_C . In effect, this expensive gas is being subsidized by the so-called gas cushion or low prices for old gas.

A third characteristic is that the rolled-in price P_R is less than the competitive price P_C . It is not possible for the price in a long-run, rolled-in pricing equilibrium to be greater than the competitive price. If the rolled-in price exceeds P_C , less than Q_C would be purchased. Hence, wells would be used along the supply curve from point A to someplace short of point I. The average of these individual marginal costs must clearly be less than P_C since each of them individually is less than P_C . Hence, the average of these marginal costs cannot possibly result in a rolled-in price that exceeds P_C . As a result, the claim by some analysts that the consumer may not benefit from average, rolled-in pricing seems incorrect.¹¹ Rolled-in pricing, per se, almost certainly

¹¹See, for example, Robert C. Means "Issues in the Debate over Natural Gas Decontrol," Public Utilities Fortnightly, October 28, 1982, pp. 18-24.

must reduce consumer prices below the competitive level. The additional consumer surplus from such a policy has presumably been judged by the Congress to be worthwhile, despite the fact that the resources used to satisfy the resulting demand are more expensive than consumers normally would be willing to pay.

A fourth characteristic of the equilibrium depicted in figure 3-2 has to do with the allegation that the entire cushion of economic rents received by keeping prices low on old gas may be spent on expensive gas. The subsequent inference that is sometimes made is that consumers will not receive the rents; instead, the producers of new, expensive gas will. There are two answers to this allegation. The simple answer is that the entire gas cushion is spent on expensive gas if the observed, rolled-in price (P_R in the diagram) is used to calculate the rent. The reason is that the equilibrium must have consumer payments equal to producer revenue, or area OP_RGQR equal to area $OAHQR$. Consequently, in figure 3-3 the triangle above marginal cost but below the rolled-in price, $AP_R C$, (shown with single cross hatching in figure 3-3) must equal the corresponding triangle below marginal cost but above the rolled-in price, CHG (shown with double cross hatching in figure 3-3). The former triangle is the value of the gas cushion if the actual, rolled-in price is used to calculate the savings realized by paying producers only their marginal costs. The latter triangle is the cost of that gas which is more expensive than the rolled-in price. Since the two triangles are equal, the entire gas cushion is spent on expensive gas.

The above conclusion, however, is quite trivial since it is a simple restatement of the fact that consumer payments are equal to the receipts of producers. The more important question is whether rolled-in pricing can bestow rents on consumers when compared to the usual, competitive circumstance in which all producers receive the same price, and not only their marginal cost. The appropriate

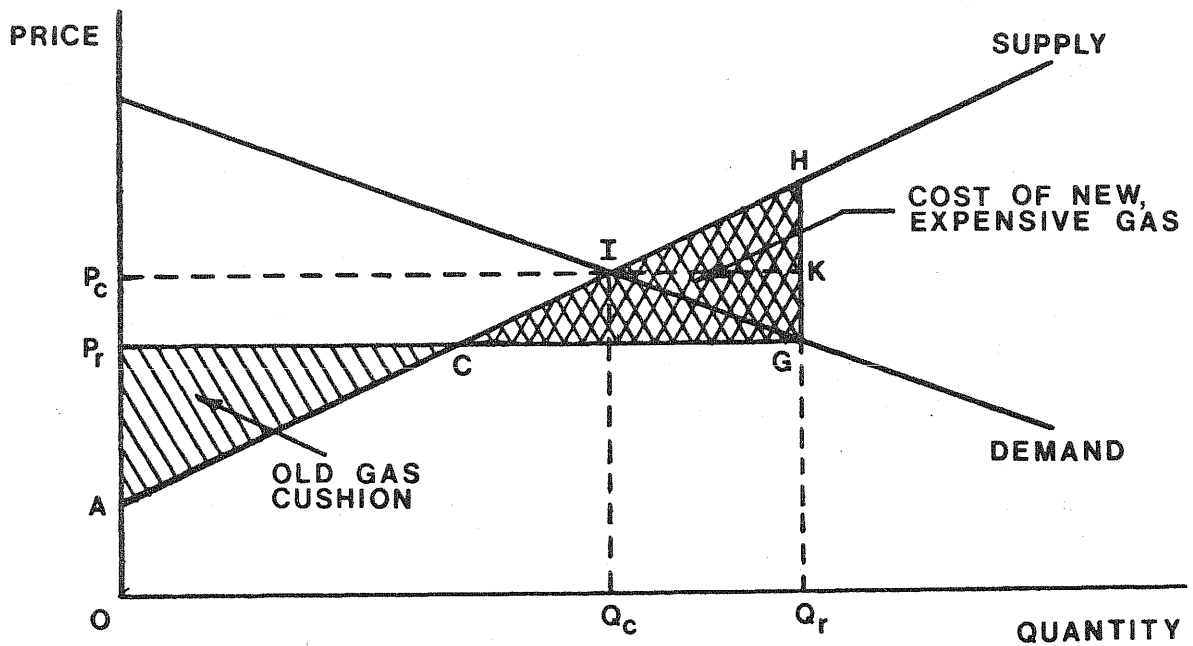


Fig. 3-3 A rolled-in pricing equilibrium showing old and new, expensive gas costs

comparison, then, is between the market clearing, competitive price and the marginal cost received by producers under rolled-in pricing. (Actually estimating the value of these rents is complicated by the fact that P_c , the competitive price, is not observed.) The rents saved using this comparison are given by the triangle AP_cI . The value of the expensive gas in excess of the competitive price is area IHK . The rents saved, AP_cI , are clearly much larger than the payments for expensive gas, IHK . Hence, the policy of rolling in or averaging the costs of various vintages of natural gas results in an increase in consumer surplus, which is financed by denying economic rents to producers.

An alternative way to understand that consumers must benefit from rolled-in pricing is to notice that, since area $AP_R C$ equals area CHG , it must also be true that the saved rents, area $AP_C I$, equal the more complex shaped area $P_R P_C I H G$. The latter area is shown explicitly in figure 3-4. It is composed of the trapezoid $P_R P_C I G$ and triangle $I H G$. The trapezoid is the gain in consumers' surplus and is shown with single cross hatching in figure 3-4. It is financed by the reduction in rents since it is some fraction of the rents $AP_C I$. The remaining triangle, $I H G$, itself is composed of two parts. The upper portion, area $I H K$ (the darkened area in figure 3-4), is the social waste of inducing the development of expensive gas. The lower portion, area $I K G$ (shown with double cross hatching), is the social

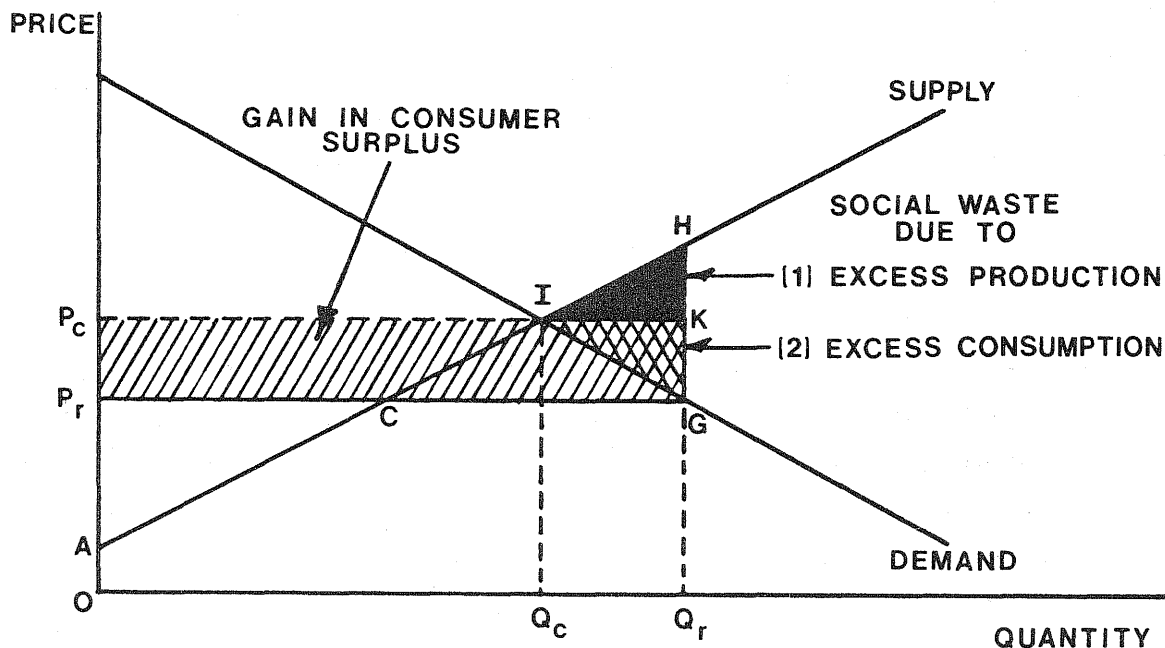


Fig. 3-4 A rolled-in pricing equilibrium showing changes in consumer surplus and social waste

waste of inducing additional demand because the rolled-in price is less than the efficient price. Hence, the rents that are denied to producers by rolled-in pricing are used to finance three activities: an increase in consumer surplus, social waste due to development of expensive gas supplies, and social waste due to excessive demand. Accordingly, it is not true that the rents are absorbed exclusively by the purchase of expensive gas.

In effect, a summary of the implications of a policy of rolled-in pricing is that by holding low the price of old gas, the average price of all vintages including unregulated, deep gas is less than would otherwise prevail in an unregulated, competitive market. Figure 3-2 illustrates the equilibrium if rolled-in pricing were perfectly administered. In reality, the FERC undoubtedly allows some producers a price higher than their own marginal cost if for no other reason than that these costs can be only imperfectly estimated. A relaxation of the price regulation to allow higher prices for old gas would cause the rolled-in price to increase and approach the competitive, market-clearing level. This relaxation might be unintentional, due perhaps to imperfect estimation, or the result of an intentional policy by the FERC to reduce the economic distortions caused by rolled-in pricing. The FERC recognized that allowing an increase in the just and reasonable price for old, flowing gas can reduce these distortions and lessen the incentive to develop expensive sources of gas that would not be economical in the absence of rolled-in pricing.¹²

Uneven Distribution of Gas Cushion

The previous section contained a discussion of the market-ordering problems or economic distortions that are inherent in a

¹²FERC, Notice of Inquiry, op. cit.

a policy of rolled-in pricing, even if it is otherwise administered perfectly. In reality, several other circumstances prevent the natural gas market from being even this well ordered. One of these is the uneven distribution of the old gas cushion among the major pipeline companies. Since wellhead prices are rolled-in separately for each pipeline, customers served by those pipelines with a larger fraction of old, low priced gas are clearly better off than those who are served by pipelines with more expensive mixes of gas.

Although there are important differences among the interstate pipelines, the most significant variation in gas cushions is between the intrastate and interstate pipelines. Most interstate pipelines have large resources of old, flowing gas by comparison. Consequently, the just and reasonable price regulation of this gas by the FERC results in the interstate pipelines having a lower rolled-in price. It is clearly preferable to be a customer of a pipeline that has the good fortune of having a large gas cushion.

This unequal distribution of old gas prompted some observers to express concern to the FERC that the intrastate pipelines may not be able to compete and that they will be priced out of the market for new, unregulated supplies of gas.¹³ The evidence on this point is mixed. As an FERC analyst points out, there must be some tendency for the low priced gas cushion to push up the price of section 107 gas or else its price would not be as high as it is, having approached \$8.00 to \$10.00 per mcf in 1981 and 1982.¹⁴ A study by the American Gas Association, however, showed a negative correlation between the price paid by interstate pipelines for section 107 gas and the fraction of old gas in the pipelines' reserves. This suggests that those

¹³Ibid.

¹⁴Means, op. cit.

pipelines with large reserves of low priced gas tend to pay lower prices for unregulated gas, despite the fact that such pipelines seemingly could better afford to pay higher prices.¹⁵ The study focused only on those pipelines having significant reserves of old gas, however. Including the others, particularly the intrastate companies, might reverse this finding.

Whether or not pipeline bidding practices are affected in the way suggested by the AGA, it is clear that the uneven distribution of the gas cushion is an important source of inequity among customers in different regions. This problem is caused fundamentally by the rolled-in pricing policy. It would largely, if not completely, disappear if all prices were decontrolled. Complete decontrol, of course, could raise prices considerably and may be politically unacceptable. If the NGPA remains unchanged, the problem will gradually disappear in the late 1980s since the portion of old gas will decline over time.

Supply Ordering Issues

The description of the rolled-in pricing equilibrium in figure 3-2 is based on a correct ordering of both supply sources and final users. That is, the implicit assumption is that natural gas wells are used in increasing order of marginal cost, while consumers are served in decreasing order of willingness to pay. In this section, aspects of the NGPA that tend to prevent this correct supply ordering are discussed. Demand ordering problems are set out in the following section.

As explained in appendix C, the NGPA ceiling prices for the various categories of natural gas depend on when the well was

¹⁵American Gas Association, "A Statistical Analysis of Bidding Trends for Decontrolled Natural Gas under the NGPA," Energy Analysis (Washington, D.C.: March 19, 1982).

spudded (when drilling began), its depth, proximity to other wells, and whether it is onshore or offshore. These categories provide various perverse incentives for natural gas wells to be developed in other than increasing order of their cost. For example, the fact that gas recovered at depths greater than 15,000 feet is not regulated allows its price to soar, while gas found at 14,900 feet can be sold only at a much lower regulated price. By establishing categories using such characteristics, the Congress has created artificially large distinctions between supply sources with quite similar marginal costs. Hence, there is some range of well depths (say, 12,000 to 15,000 feet) that will not be developed because drilling deeper offers a higher reward. By producers skipping over such a set of drilling opportunities, more expensive wells are completed before all cheaper opportunities are exhausted. Canto and Melich describe this phenomenon as being equivalent to a 100 percent tax on the profits from wells drilled from 12,000 to 15,000 feet.¹⁶

Figure 3-5 is a stylized representation of the effect of the NGPA price categories on the supply curve. The original and correct supply curve is S. Because of the abrupt distinctions among gas categories, there are segments of the supply curve that are not developed. The wells, for example, that are close to the boundary between shallow and medium depth wells are not drilled. In the figure, those wells with marginal costs from points A to B are uneconomical because the ceiling price for medium wells makes drilling them more advantageous than drilling a near-medium well allowed only a shallow category price. Consequently, wells from A to B tend to be bypassed, and more expensive wells from B to C are used first. Resources are clearly being misallocated in this instance. Figure 3-5 also shows wells from points C to D being excluded because they are near the wells defined as having deep, unregulated gas. The result is that the supply curve

¹⁶See V. Canto and K. Melich, "Natural Gas Decontrol: The Road to Lower Energy Prices," Public Utilities Fortnightly, Oct. 28, 1982, pp. 31-39.

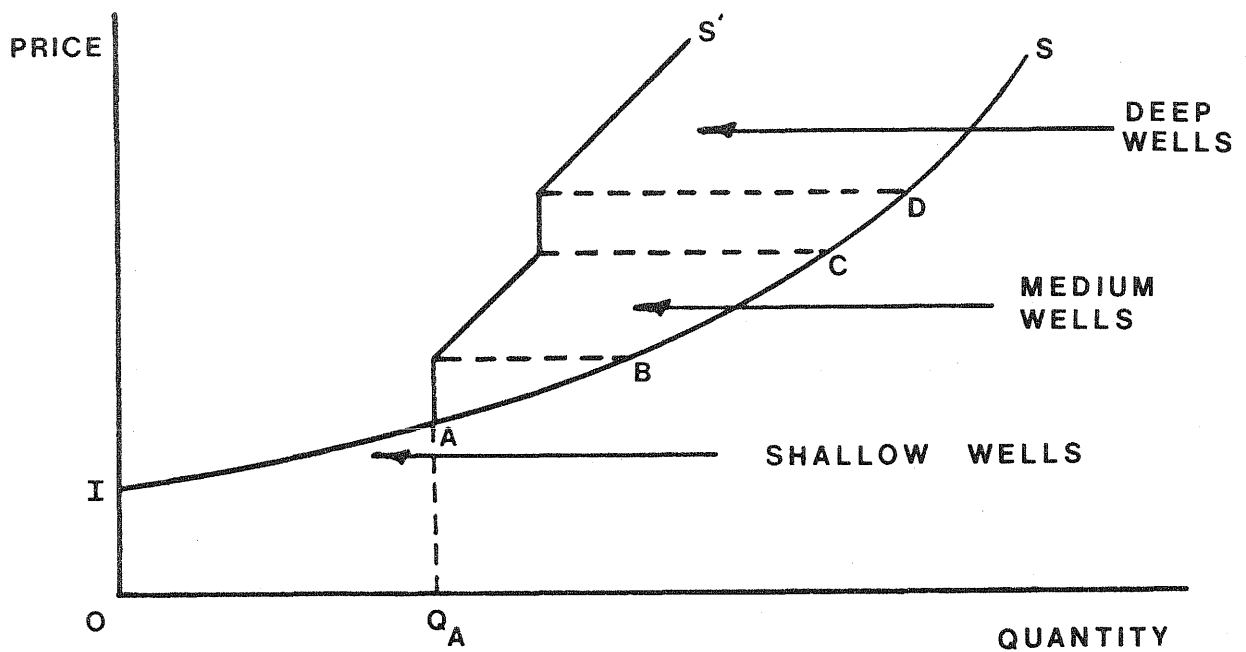


Fig. 3-5 Incorrect supply ordering

shifts from S to S' and hence, quantities supplied beyond the amount Q_A cost more than they would in a correctly ordered market.

The economic value of the resource misallocation is the area between the original and shifted supply curves, up to the point of actual production. Although the calculation of this value is theoretically straightforward, actually estimating it in practice is very difficult because the original supply curve S is not observed. The difficulties in estimating supply functions from observable data are well known, those involved with estimating an unobserved supply function are several orders of magnitude larger.

Another way in which resources are misallocated is that some producers can receive a higher price for their gas if they can redefine it to fit into a more expensive NGPA category. Hence, some producers have an incentive to spend time and resources on changing categories. This is entirely unproductive, and although it can be discouraged by legal penalties it probably cannot be eliminated.

An example of how rolled-in pricing creates supply disorder is the development of synthetic gas. Assuming that the policy of rolled-in pricing has sufficient permanence that the industry believes it will persist, local gas distributors have little or no incentive to build synthetic gas plants if the cost is above the rolled-in price. The result, from their point of view, would be an increase in their overall payments for gas acquisitions. In reality, of course, such may not be the case, depending on which supplies are reduced by the pipeline as the synthetic gas becomes available. If the most expensive gas is curtailed and synthetic gas costs less than this curtailed value, then it is possible that the city-gate rolled-in price may fall sufficiently to make the synthetic plant economical for the distributor. The difficulty is that the benefits of a reduced pipeline rolled-in price are conferred not only on the gas distributor that decides to build a synthetic facility but also upon all other final customers of the pipeline, since the pipeline's rolled-in price is reduced for all users as expensive section 107 gas is supplanted. Consequently, local gas distributors probably cannot gain by investing in synthetic technology, even though such an investment might be socially wise.

Even though gas distributors may have little incentive to pursue synthetic sources of gas, there is nothing to prevent an independent energy company from undertaking such an investment. If a major oil company, for example, were to build a coal gasification plant, it would be free to enter into a contract with a major pipeline company.

If the price of the synthetic product were lower than the pipeline's most expensive source, it would be in the interest of both parties to engage in such a contract. That is, the free rider problem facing a local distributor (that other distributors and final users will benefit if he is successful in building a plant that supplants more expensive gas) does not affect independent energy companies.

The dilemma of free riders, however, is not the major reason why rolled-in pricing may prevent development of synthetic sources of natural gas. Rather, it is the uncertainty of the policy itself. It may be beneficial for an independent energy company to build a synthetic plant if rolled-in pricing continues and the plant can substitute for expensive, section 107 gas selling above the market clearing price. If the policy of vintage pricing is discontinued, however, all gas sources above the market clearing price would no longer be used, including some section 107 gas and possibly the synthetic substitute if its price also exceeds that of the market. Energy companies realize this, but have difficulties in assessing the risk that the pricing policy might be discontinued and in estimating the market clearing price in its absence. Consequently, a prudent, risk averse investor is unlikely to be interested in synthetic gas sources given the political uncertainty that surrounds the NGPA and the various proposals to modify it.

These supply ordering problems are part of the reason why many observers believe that decontrol of natural gas prices would be in society's overall best interest. Decontrol would eventually have the effect of correctly ordering all sources of natural gas, although there undoubtedly would be some temporary, echo effects from existing contracts. An example might be an unusually high take-or-pay provision in an existing contract that would not be viable if prices were not controlled. Some time may be required before the importance of such contract clauses declines, either because they are renego-

tiated or because other contracts become more numerous. The drawback, of course, to total decontrol of natural gas prices is that a substantial amount of economic rents would then flow from consumers to producers. Whether the resource allocation gains are worth the resulting redistribution of rents is a political question that the Congress may have to address. As is commonly the case in public policy matters, economic efficiency must be weighed against social views of an equitable distribution of wealth.

Demand Ordering Issues

Two pieces of federal legislation affect the order in which final users of natural gas are served. Together, the overall effect on demand is much less important than the supply disorder just discussed. The two laws are the incremental pricing provisions of the NGPA and the Powerplant and Industrial Fuel Use Act of 1978 (FUA).

Phase I of the incremental pricing program is currently in effect and covers large boiler facilities, those over 300 mcf per day excluding electric utilities, agricultural consumers, schools, and hospitals. Phase II would greatly extend the coverage of the program. It was developed by the FERC but vetoed by the House of Representatives. That veto was recently overturned by the U.S. Supreme Court. However, phase II incremental pricing appears to face serious political opposition and is likely to be dismantled or discarded by the Congress.

The FERC administers the incremental pricing program through its control on pipeline wholesale prices, as described in appendix C. Each pipeline is required to establish an account showing the total value of the gas purchased in excess of some limit, as defined by the FERC. Each pipeline is also required to compute the Maximum Surcharge Absorption Capacity (MSAC) for each of its distributors or final

customers. The MSAC for the gas sold to them is determined by the difference between the price of the alternate fuel, as established by the FERC, and the base price charged to each large boiler not exempt from incremental pricing. The excess or expensive gas account must be collected first from non-exempt large boiler facilities up to the limit of the MSAC. This has the effect of raising the price of gas paid by large boiler users up to the price of the alternate fuel, which has been established by the FERC to be high sulfur, number 6 residual fuel oil in all regions of the country.

Several features of this incremental pricing regulation are worthy of note. First, the FERC can only affect wholesale prices. The price of residual fuel oil is at the retail level, however. Consequently, it is possible that mistakes in computing the MSAC account could result in natural gas prices exceeding those of the alternate fuel. Second, in the seven-year time frame of the NGPA during which prices of all natural gas categories rise, the effect of the incremental pricing provision is initially to impose the burden of higher prices on non-exempt large boilers. Eventually, the boiler gas price cannot exceed that of the alternate fuel, however. As natural gas prices continue to rise thereafter, the burden will fall entirely on the exempt group. It is possible that the second phase of this dynamic process will occur at the same time that many prices are decontrolled in 1985. This possibility has prompted some observers to predict particularly large price increases for residential and other exempt uses in 1985.

Third, the public utility commissions of individual states can capture the benefits of the state's large boiler MSAC accounts for the residential and other exempt users in their states by reallocating the distributor's fixed cost so that the boiler user's base price is equal to that of residual fuel oil. This directly reduces the price to other users since large boilers are paying a larger portion of the

distributor's fixed costs. This type of strategic behavior by state commissions is not opposed by the large boiler customers since they pay the same price regardless. The primary disadvantage to this policy, which has been pursued by more than half the states, is that it prevents the benefits of incremental pricing from being spread over the pipeline's entire service area. Instead, the benefits are contained within a single state. Those states with rather large MSAC accounts can benefit by capturing these for themselves and not allowing them to be different over the pipeline's system.

The FERC has expressed concern that the dynamics of the incremental pricing program may proceed differently because so many states have raised boiler user prices to that of the alternate fuel.¹⁷ In particular, states may not know when or if the incremental pricing period becomes obsolete, which could happen if natural gas prices increase sufficiently so that the boiler user price exceeds the residual fuel oil price. If states continue to hold boiler prices down to the resid price under such circumstances, residential and other exempt customers will bear a larger portion of the burden than they would if the FERC exercised more direct control over the incremental pricing program.

A second law affecting the order of demand is the Fuel Use Act, which specifies certain categories of users that may not burn natural gas. This legislation has been mostly repealed, in effect, by new rules that set a goal of a five percent reduction in natural gas use by 1990 for electric utilities and some industrial boilers called Major Fuel Burning Installations. There is, however, no penalty for not complying with this goal, and hence there are no real restrictions on existing users. Electric utilities cannot install new gas burning

¹⁷See FERC, Notice of Inquiry, op. cit.

electric plants, and there are no exemptions to this particular rule. Otherwise, most new industrial boilers have recently been able to obtain exemptions.

Summary

The discussion in this chapter covers the distortions in the natural gas market that have been created by or at least exacerbated by the combination of the NGPA, contract clauses within the industry, and economic circumstances. The framers of the NGPA wanted to prevent the flow of excess profits from consumers to the owners of old gas wells and to provide for a seven-year, smooth transition during which the price of new gas would rise to be competitive with oil. The first objective has been largely met. It is fair to say, however, that the transition has not been smooth nor of the nature envisaged by the Congress.

The manner in which gas ceiling prices are imposed under the NGPA has contributed to these difficulties. The price controls are established in absolute terms (dollars per mcf) that leave very little opportunity for adjustments in response to changing energy market conditions.

Certain clauses in pipeline-producer contracts hinder the transmission of price signals between producers and end users. Take-or-pay clauses have operated recently to distort the mix of gas taken by the pipelines. New gas contracts tend to have high take-or-pay fractions. As demand has declined, production of old gas has often been cut back first when society would have been served better by first reducing takes of the most expensive gas.

Minimum bills in pipeline-distributor contracts also restrict the rapid flow of price signals when market conditions change. Also, certain indefinite price escalator clauses in producer-pipeline

contracts have created some fear that the price of gas temporarily may exceed the Btu-equivalent price of oil. This is because a few contracts tie the gas price to 110 percent of the oil price while many other contracts have most favored nation clauses that tie the price to that of other natural gas prices in a certain area. The combination of the two clauses could cause a temporary price fly-up until the contracts are renegotiated.

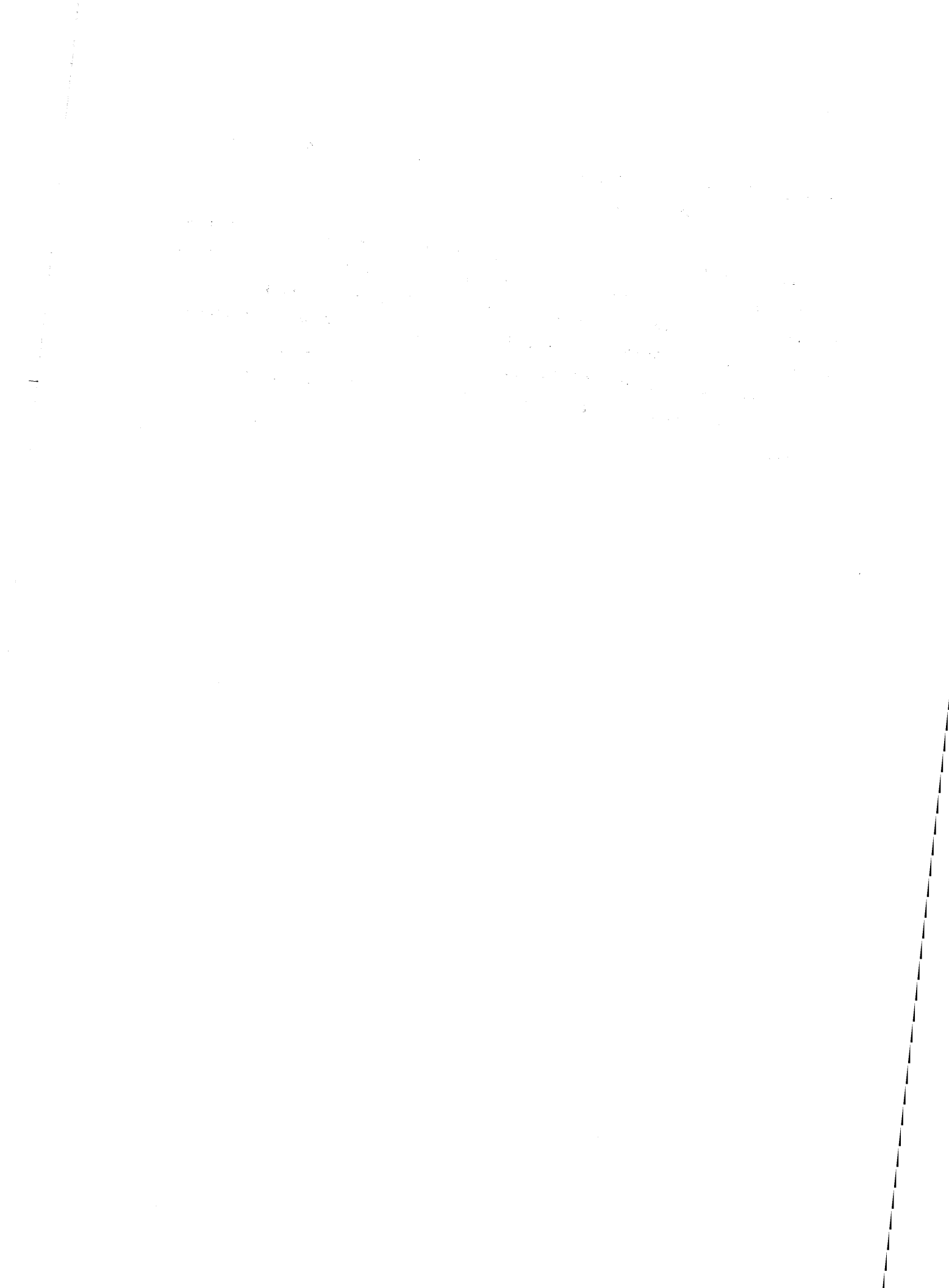
All the above distortions are examples of how the natural gas market is prevented from operating with short-run efficiency. There are other, long-run distortions in addition to these. The NGPA, for example, prevents excess profits from flowing to owners of old gas wells by a system of vintage pricing. It accomplishes this goal; however, there is at least some resource misallocation, even in the long run, associated with vintage pricing. Such a system creates a rolled-in price that is the average of a constellation of vintage prices. The rolled-in price is lower than the market clearing level, encouraging inefficient consumption. In addition, this pricing system encourages the development of expensive sources of gas since the cost of these can be averaged with the lower cost of cheaper gas wells.

Another long-run distortion occurs because the supply of old, price regulated gas is unevenly distributed among pipelines. Those with large gas cushions have lower overall prices creating inequities among customers of different transmission companies. Intrastate pipelines, in particular, have a disadvantage in this regard compared to interstate companies with large volumes of old gas.

The gas categories established by the NGPA cause some inefficient ordering of gas supplies. There is some incentive to drill for deeper sources of gas before exhausting the opportunities to explore at more shallow depths. The Fuel Use Act similarly creates some demand

ordering problems; however, these appear to be quite minor in the opinion of most observers.

The distortions in the natural gas market analyzed here, together with the uncertainties and controversies described in chapter 2, have created a public outcry against the market failings in the gas industry under the NGPA. The ensuing debate has resulted in proposals for a variety of federal actions for changing the course of deregulation. The next chapter contains an analysis of these proposals.



CHAPTER 4

CONGRESSIONAL PROPOSALS FOR DEALING WITH MARKET DISTORTIONS

The market distortions in the natural gas industry under the Natural Gas Policy Act of 1978 have given rise to demands for corrective legislation. Almost fifty bills affecting the gas industry have been introduced in the Congress in the first six months of 1983. Most of the legislative proposals that have come before the Congress can be grouped into three major categories: (1) proposals that deal with the NGPA plan for wellhead price decontrol, (2) proposals that directly or indirectly modify contract provisions in the natural gas industry, and (3) proposals that deal with the market structure of the gas industry by proposing either a common or contract carrier approach to pipeline regulation. In addition, other legislative proposals would modify miscellaneous existing gas regulations, such as the type of rate design allowed by the FERC.

Each bill in the three major categories involves a trade-off between market efficiency and fairness. For example, the gas market would probably be more economically efficient if a legislative proposal that provided for total deregulation of gas wellhead prices were implemented. However, if it were, gas customers would probably pay higher prices for exactly the same commodity. Also, some interstate pipeline companies would lose a portion of their gas cushion, while producers of high-cost gas might have to market their product at a loss. Other legislative proposals also involve a trade-off between affecting market efficiency and dealing fairly with the legitimate interests of various parties. Because the interests of the various members of the gas industry and the consuming public differ, major industry associations and consumer groups would, of course, support different legislative proposals.

Bills in each of the major categories of legislative proposal were introduced in the U.S. House of Representatives and the U.S. Senate in the first six months of 1983. Our categorization of the bills, introduced between the opening of the session in January and June 5, 1983, is shown in tables 4-1 and 4-2. These tables are organized so that one can easily find a bill: table 4-1 contains bills in the order that they were introduced in the House, while table 4-2 contains bills in the order that they were introduced in the Senate. In each table, bills containing resolutions are presented first, and the name of the principal sponsor of the legislation appears with the bill number. The three major categories of proposal are divided into subcategories in the tables; for example, altering "take-or-pay clauses" is a subcategory of "contract provisions." For each bill, an "X" appears in a subcategory if the bill explicitly deals with a subject in that category. A bill can fall into several subcategories if it contains several proposals for reform. Of course, if a bill contains no explicit price control provision, no "X" appears in the price control category even though the bill, by its silence, supports continuing the NGPA plan of phased, partial decontrol.

The first three sections of this chapter cover the various legislative proposals that have been introduced in the Congress for each of the three major categories of legislative proposals. Other proposals that do not neatly fit into one of the major categories are discussed in the fourth section. In the fifth section, special attention is paid to selected bills of particular interest to state regulators: (1) the bill supported by the Reagan administration, (2) the bill endorsed by the Executive Committee of the National Association of Regulatory Utility Commissioners, and (3) the bill endorsed by the Illinois Commerce Commission. (A bill introduced by Senator McClure in late June 1983, which substitutes for the Reagan Administration bill and which is expected to pass out of the Senate Energy Committee, is not included here because it emerged in importance just before publication of this report.)

TABLE 4-1

LEGISLATION DEALING WITH THE GAS INDUSTRY INTRODUCED INTO THE U.S. HOUSE OF REPRESENTATIVES DURING THE FIRST SIX MONTHS OF 1983

BILL NUMBER AND PRINCIPAL SPONSOR	CATEGORY OF PROPOSAL													
	PRICE CONTROLS			CONTRACT PROVISIONS								CARRIER STATUS		OTHER
	Partial Decontrol	Total Decontrol	Extend/Reimpose Controls	Take-or-Pay Clauses	Market-out Clauses	Indefinite Price Escalators	Most Favored Nation Clauses	Redetermination Clauses	Guaranteed Pass-through	Purchased Gas Adjustment Clauses	Minimum Bill Provisions	Contract Carriage	Common Carriage	Modifying Rate Design
H. Con. Res. 29 Collins			X											
H. Res. 38 Gaydos			X											
H. J. Res. 58 Dixon													X	
H. Con. Res. 88 Donnelly	X													
H. Con. Res. 96 Whittaker														X
H. R. 4 Michel				X	X				X		X			
H. R. 131 Gramm		X							X					
H. R. 232 Nowak			X											
H. R. 482 Byron													X	
H. R. 583 Glickman			X											
H. R. 619 Kastenmeier			X											
H. R. 705 Tauke				X	X	X	X		X					
H. R. 796 Gaydos				X					X	X				
H. R. 827 LaFalce				X										
H. R. 873 Oberstar				X					X	X				
H. R. 909 Volkmer			X											
H. R. 910 Volkmer				X	X	X	X	X						
H. R. 1359 Skelton	X													
H. R. 1422 Young			X											
H. R. 1685 Hertel				X		X			X		X			
H. R. 1686 Hertel			X		X									
H. R. 1752 Addabbo				X	X	X					X			
H. R. 1759 Coleman			X	X					X	X				
H. R. 1760 Corcoran		X		X	X	X			X		X			X
H. R. 2012 Collins			X	X	X				X					X
H. R. 2054 Bedell											X			
H. R. 2164 Tauke				X		X			X		X			X
H. R. 2182 Schroeder										X	X			
H. R. 2499 Ritter											X			
H. R. 2508 Slattery				X	X		X				X			
H. R. 2565 Corcoran												X		

Source: NRRI Staff

TABLE 4-2

LEGISLATION DEALING WITH THE GAS INDUSTRY INTRODUCED INTO THE
U.S. SENATE DURING THE FIRST SIX MONTHS OF 1983

BILL NUMBER AND PRINCIPAL SPONSOR	CATEGORY OF PROPOSAL														
	PRICE CONTROLS			CONTRACT PROVISIONS								CARRIER STATUS		OTHER	
	Partial Decontrol*	Total Decontrol	Extend/Reimpose Controls	Take-or-Pay Clauses	Market-out Clauses	Indefinite Price Escalators	Most Favored Nation Clauses	Redetermination Clauses*	Guaranteed Pass-through Purchased Gas Adjustment Clauses	Minimum Bill Provisions	Contract Carriage Common Carriage Modifying Rate Design			Miscellaneous	
S.J.Res.46 Cranston														X	
S.Res.75 Percy														X	
S.60 Kassebaum			X	X				X						X	
S.239 Jepsen				X	X	X	X	X							
S.291 Danforth				X		X		X							
S.293 Eagleton			X												
S.370 Percy														X	
S.512 Nickles														X	
S.615 McClure		X		X	X	X			X		X			X	
S.689 Heinz				X	X	X					X				
S.740 Sasser					X										
S.823 Jepsen				X	X	X		X			X			X	
S.996 Kassebaum				X	X	X		X		X	X				
S.1017 Bradley											X				
S.1049 Hart				X	X										
S.1119 Dixon												X			

Source: NRRI Staff

*No bills were introduced in the Senate dealing with partial decontrol and redetermination clauses. These columns are included here to facilitate comparison with table 4-1.

For each category of proposal, the positions of the major interest groups are discussed. The discussion contains an analysis of the trade-offs between economic efficiency and fairness involved in each of the proposals.

Proposals Affecting Wellhead Prices

One major category of legislative proposal is those that deal with the existing plan of wellhead price decontrol. There are three subcategories of such proposals: proposals that provide for a partial decontrol of gas wellhead prices, proposals that provide for a total decontrol of gas wellhead prices, and proposals that extend or reimpose wellhead price controls on gas.

Partial Decontrol

The current plan of decontrol provided under the NGPA is a phased, partial decontrol. As discussed in chapter 2, the decontrol is partial because only new gas and high-cost gas will be decontrolled by the NGPA. The wellhead prices of old interstate gas and some old intrastate gas will not be decontrolled.

H.Con.Res. 88, sponsored by Congressman Donnelly, explicitly expressed that it is the sense of the Congress that the current schedule of domestic natural gas decontrol should not be accelerated. H.Con.Res. 88 would, thus, explicitly endorse the current plan of phased, partial decontrol.

In addition, H.R. 1359, a bill sponsored by Congressman Skelton provides for phased, partial decontrol. The bill would amend the NGPA so that after the enactment of the bill the Federal Energy Regulatory Commission could not raise the maximum lawful price through administrative decontrol to a level higher than the otherwise applicable ceiling price under the NGPA. The administrative decontrol

that has been proposed by the FERC is discussed later in this section and in appendix C. H. Res. 38, introduced by Congressman Gaydos, has a similar provision. This resolution states that it is the sense of the House of Representatives that the FERC should take no action to accelerate the decontrol of gas.

Another bill, H.R. 2164, which was introduced by Congressman Tauke and is endorsed by the NARUC Executive Committee, and its companion bill, S. 823, provide for partial decontrol. While these bills have no explicit provision to accelerate the operation of the NGPA and therefore do not appear in the first column of the tables, the effect of these bills might be to accelerate partial decontrol. These bills contain provisions that provide for some adjustment of take-or-pay requirements for high cost gas down to 50 percent of the volume for which the pipeline has contracted. Such a provision would tend to operate first on all high-cost gas, and then on all new gas. The untaken new gas and high-cost gas could be resold by the producer to any purchaser at whatever the market would bear, in effect deregulating whatever volume of new gas and high-cost gas for which there are reduced takes. The NARUC endorsed bills could have the effect of creating a deregulated spot market in all new and high-cost gas, an effect similar to accelerating the NGPA.

Other legislative proposals, which may modify contract provisions or affect pipeline carrier status, do not explicitly address modifying price controls. Many of the bills dealing with carrier status decontrol gas not purchased by the pipelines and so indirectly circumvent NGPA ceiling prices. But, the bills that deal only with pipeline contract provisions and not prices would implicitly allow the phased, partial decontrol plan in the NGPA to go forward unchanged. These bills would include H.R. 4 introduced by Congressman Michel; H.R. 482, introduced by Congresswoman Byron; H.R. 705, introduced by Congressman Tauke; H.R. 796, introduced by Congressman Gaydos; H.R.

827, introduced by Congressman LaFalce, H.R. 873, introduced by Congressman Oberstar; H.R. 910, introduced by Congressman Volkmer; H.R. 1685, introduced by Congressman Hertel; H.R. 1752, introduced by Congressman Addabbo; S. 239, introduced by Senator Jepsen; S. 291, introduced by Senator Danforth; S. 370, introduced by Senator Percy; S. 689, introduced by Senator Heinz; S. 740, introduced by Senator Sasser; and S. 1049, introduced by Senator Hart. As can be seen by this rather lengthy list of bills, many of the legislative proposals currently pending in the Congress would allow the NGPA to continue on its schedule of phased, partial decontrol.

Total Decontrol

Some of the legislative proposals call for a total decontrol of all natural gas wellhead prices. Such total decontrol involves decontrolling old gas as well as all new and high-cost gas. Total decontrol of gas wellhead prices can be either immediate or phased in over a period of time.

Some legislation calls for total decontrol of wellhead prices, but none of the current legislative or administrative proposals clearly provides for immediate, total decontrol. However, the legislation proposed by the Reagan administration could operate in a way similar to immediate, total decontrol because the bill provides that all existing contracts covering old, new, and high-cost gas may be immediately renegotiated by the pipelines and producers. But, phased, total decontrol is a more likely result because the renegotiation of these contracts will probably take time. Also, some contracts are unlikely to be renegotiated until January 1, 1985, the date on which President Reagan's proposed legislation, H.R. 1760 and S. 615, would provide that either the pipeline or the producer could unilaterally abrogate any contract that had not yet been renegotiated.

H.R. 1760 and S. 615 are thus more likely to provide for phased, total decontrol of gas than they are to provide immediate, total decontrol. The Reagan plan provides for the immediate decontrol of gas that is first produced after its enactment.

Congressman Gramm has also introduced a bill that would result in a phased, total decontrol of gas. His bill, H.R. 131, would immediately deregulate gas drilled after January 1983, while phasing out controls on all gas, including old gas, by January 1985.

In addition to the Reagan and Gramm plans, total decontrol of wellhead prices could be simulated through administrative action without new legislation. Under the NGPA section 107(c)(5), the FERC has the authority to provide an "incentive price" for high-cost gas. The FERC could decide that the appropriate incentive price is the Btu-equivalent price of competing, alternate fuels in order to approximate the market clearing price that would result under decontrol. The FERC has initiated a rulemaking to consider this action. Furthermore, the FERC has issued a notice of inquiry to consider a much broader action to approximate total decontrol by administrative action. This action is to eliminate the vintages of old gas and to set the price of all old gas at the "commodity value of gas," chosen to be some proxy for the market clearing price of gas as the Btu-equivalent price of number 6 fuel oil. The authority for this action is in the NGPA, which allows the FERC to increase the NGPA ceiling price for old interstate gas (cf. section 104(b)(2)), gas under rollover contracts (cf. section 106(c)), and certain other types of gas (cf. section 109(b)(2)) -- provided the resulting price is just and reasonable. The FERC may argue that the commodity value of gas is just and reasonable. The authority to raise the ceiling price does not apply to old intrastate gas (section 105), and so the FERC cannot approximate total decontrol immediately. However, as old intrastate gas contracts expire, the 105-gas will become 106-gas under a rollover contract to which the FERC administrative action would apply.

There are trade-offs between market efficiency and fairness with total decontrol. Total decontrol would tend to make the gas market more economically efficient, but also to raise customer rates without any improvement in service, to hurt some deep gas producers, and to remove low-cost gas cushions from some interstate pipelines.

Extend or Reimpose Price Controls

Many of the legislative proposals would delay decontrol of wellhead prices. Such delay could consist of a gas price freeze, a delay and extension of the operation of the NGPA, reimposition of price controls for an indefinite period of time, or a combination of these actions.

Congresswoman Collins submitted a concurrent resolution, H.Con. Res. 29, stating that it is the sense of the Congress that the decontrol of natural gas wellhead prices currently scheduled in 1985 should not occur and that no administrative action is to be taken that has the effect of decontrolling gas wellhead prices. The concurrent resolution also states that it is the sense of the Congress that wellhead price controls should be made applicable to high-cost gas that is currently decontrolled.

Several bills have provisions to freeze gas prices at recent levels. A bill, introduced by Congressman Nowak, H.R. 232, would have prohibited any increase in natural gas wellhead prices during a six-month period beginning January 1, 1983. This bill also provides that the price increases that were scheduled to take effect during the control period are to be disregarded once the control period ends. Congressman Glickman introduced a bill, H.R. 583, that amends the NGPA so as to impose a moratorium on gas price increases. The bill provides that the maximum lawful price for any first sale of gas from January 6, 1983 through January 1, 1985 will be the maximum lawful price that was applicable on October 1, 1982. If the gas was not

covered by price controls on October 1, 1982, the maximum lawful price is to be the contract price specified for deliveries on October 1, 1982. If there was no contract price, the maximum lawful price is the average of the prices paid on October 1, 1982 for deliveries from the three nearest wells for which there was no maximum lawful price on October 1, 1982. The bill would also extend price controls from January 1, 1985 to January 1, 1987 and extend the standby authority of the Congress to continue price controls from July 1, 1985 to July 1987. Upon the expiration of the price freeze, the maximum lawful price for any first sale would increase from the October 1, 1982 level at the rate specified by the NGPA.

Congressman Volkmer's bill, H.R. 909, would also impose a freeze on the maximum lawful price applicable to any first sale of gas and also extend price controls. His bill would freeze the maximum lawful price applicable to any first sale from January 25, 1983 through January 1, 1985 at the level applicable on September 1, 1982. The bill would also reimpose price controls on high-cost gas from wells for which the drilling began before January 25, 1983. The price controls for such high-cost gas would be the contract price specified for deliveries on September 1, 1982. If no contract price was specified, the maximum lawful price would be the average of the prices paid on September 1, 1982 for deliveries from the three nearest wells for which there was no maximum lawful price on September 1, 1982. At the end of the freeze period, the maximum lawful price would increase from the September 1, 1982 level at the rate specified by the NGPA. Price increases that would have occurred during the freeze are disregarded. The bill also provides for a two-year extension of the NGPA price controls.

Congressman Kastenmeier also introduced a bill to amend the NGPA by imposing a freeze on natural gas prices. His bill, H.R. 619, is similar to H.R. 583 in that it provides for the freezing of the

maximum lawful prices at the level of the prices on October 1, 1982. It also has similar provisions concerning natural gas not covered by wellhead controls on October 1, 1982. However, H.R. 619 is different from H.R. 583 in that it provides for the repeal of all provisions in the NGPA relating to the decontrol of gas prices. The bill does not specify the duration of the price freeze; the bill, in effect, provides for a freezing of the maximum lawful price of gas at October 1, 1982 levels.

Congressman Hertel introduced a bill, H.R. 1686, to amend the NGPA by freezing the maximum lawful price under any contract signed before the bill takes effect at the price applicable under the contract for gas deliveries on January 1, 1983. For contracts entered into after the bill takes effect, the maximum lawful price, except in the case of high-cost gas, would be that applicable for deliveries made on January 1, 1982 for that category of gas. In the case of high-cost gas, the maximum lawful price would be the maximum lawful price that would have been applicable had the gas not been decontrolled. However, contracts are exempt from the price freeze if they contain a market-out clause, and, for contracts entered into on or before the effective date of the bill, if the contract price is renegotiated.

H.R. 1759, a bill introduced by Congressman Coleman, would freeze the maximum lawful price for any first sale or delivery of gas from December 13, 1982 through January 1, 1985 at the level of the maximum lawful price applicable on October 1, 1982. For deregulated high-cost gas from a well for which surface drilling began before December 13, 1982, the maximum lawful price would be the contract price specified for deliveries on October 1, 1982. In the absence of such a price, the maximum lawful price is to be the average price paid for deliveries made to the three nearest high-cost gas wells.

Senator Kassebaum introduced a bill, S. 60, to amend the NGPA by freezing the maximum lawful price of gas for the period October 1,

1982 through January 1, 1985 at the October 1, 1982 level. The bill provides that prices for any first sale of gas that are lower than the maximum lawful price in effect on October 1, 1982 may increase by the lesser of the rate provided for in the contract and the annual inflation adjustment factor up to the level of the October 1, 1982 maximum lawful price. For gas not covered by wellhead price controls on October 1, 1982, the bill provides that the maximum lawful price for the freeze period is the contract price. If no contract price is specified, the maximum lawful price is the price paid for comparable gas. Upon expiration of the freeze period, the maximum lawful price for each category of gas increases from the October 1, 1982 level at the rate specified by the NGPA. The bill also extends gas price controls and Congressional standby price control authority for two years.

Senator Eagleton introduced a bill, S. 293, that would freeze wellhead prices from January 31, 1983 through December 31, 1984. During the freeze period, the maximum lawful price is to be the maximum lawful price in effect on August 31, 1982. For gas for which there was no applicable maximum lawful price on August 31, 1983, the maximum lawful price during the freeze is to be the contract price specified for deliveries on August 31, 1982. If there is no contract price specified, the maximum lawful price is to be the average price paid on August 31, 1982 for deliveries of gas from the three nearest wells for which there was also no maximum lawful price on August 31, 1982. The bill states that on expiration of the price freeze, the maximum lawful price will increase from the August 31, 1982 level at the rate specified by the NGPA. The bill also extends price controls and the standby authority to reimpose price controls by two years.

Other bills would extend price controls for a longer time. H.R. 1422, introduced by Congressman Young, would amend the NGPA so as to provide for an extension of price controls beyond 1985. The bill would also reimpose price controls on high-cost natural gas produced

from a well drilled after the date of the bill's enactment. Also, the bill would amend the NGPA by eliminating the monthly indexing of wellhead prices and by allowing instead increases in wellhead prices only to the extent justified by increases in production costs.

Congresswoman Collins introduced a bill, H.R. 2012, that would extend wellhead price controls beyond 1985 and would reimpose price controls on previously decontrolled high-cost gas. The maximum lawful price for high-cost gas would be the maximum lawful price for section 102 new gas. The bill would also roll back the maximum lawful price of all price-controlled categories of gas by requiring a recomputation of price ceilings to eliminate increases since April 1977 in price ceilings in excess of the rate of inflation. The bill would also, in a manner similar to H.R. 1359, eliminate FERC authority to increase prices administratively.

The Positions of the Interest Groups¹

As might be expected, the various interest groups have differing views on the desirability of legislative proposals to alter wellhead price controls. The views of typical producer, pipeline, distribution company, and customer interest groups are described below.

¹The discussion here is drawn from material in U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce, Natural Gas Issues Hearings, Part I, Vols. 1 and 2, Part 2. 97th Cong., 2d sess., 1982; U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels, "Statement of Robert A. Hefner, III." 98th Cong., 1st sess., March 24, 1983 (to be published); U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels, "Statement of Jerome J. McGrath, President, Interstate Natural Gas Association of America." 98th Cong., 1st sess., March 24, 1983 (to be published); U.S., Congress, Senate, Committee on Energy and Natural Resources, Current Conditions in the Natural Gas Market, Hearing. 97th Cong., 2d sess., 1982.

Some producers support total decontrol of gas prices. Nicholas Bush of the Natural Gas Supply Association, for instance, blames the NGPA for a variety of market ordering problems, including the gas cushion enjoyed by some (mainly interstate) pipelines which enables such pipelines to have an advantage in competing for new gas. The price of gas might thus be bid above the market clearing price. In Bush's view, phased decontrol of all gas (old and new) would eliminate such problems, doing away with major differences in average costs among pipelines and ensuring that proper economic signals are sent. This would lead to optimal exploration and production of gas. Of course, decontrol also allows producers to receive any difference between market price and production cost.

Other producers, mainly independents, do not agree with decontrol, especially decontrol of old gas. Robert A. Hefner III, representing the Independent Gas Producers Committee states that independents own and produce most of the nation's new gas supplies, while producers affiliated with the major oil companies own and produce most of the old gas. According to Hefner, it is natural for the major producers to seek decontrol of old gas prices, but such decontrol would lead to a substantial transfer of revenues from smaller independent producers to gas producers affiliated with major oil companies because it would raise old gas prices and lower new gas prices. Total decontrol would be disastrous for the independents. Hefner acknowledges the complexity of the NGPA, but claims that the industry has learned to live with it and that it has provided predictability. Prices are falling and will moderate under the NGPA.

Other parts of the industry, such as pipelines, also have mixed views. For example, Jerome J. McGrath of the Interstate Natural Gas Association of America, which represents mainly interstate pipelines, proposes phased, partial decontrol of wellhead prices in order to avoid a fly-up in gas prices in 1985 due to indefinite price escalators. This Association favors decontrolling "new, new" gas now,

so it can respond to market demand.² But, it opposes decontrol of old section 102 gas (as called for in the Reagan bill) because in its view such decontrol would lead to major price increases for pipelines with a lot of old gas.

The American Gas Association also argues against decontrolling old gas. Such decontrol, resulting in increases in old gas prices, would not, according to George H. Lawrence of the AGA, exert much downward pressure on new gas prices. (The AGA also expresses concern over a fly-up due to indefinite price escalators.)

Intrastate pipelines, however, argue for deregulation of wellhead prices, blaming the NGPA for the existence of interstate pipeline gas cushions that put them at a disadvantage vis-a-vis the interstate pipelines. J. L. Terrill of the Louisiana Intrastate Gas Corporation, for instance, emphatically stated that no federal wellhead price regulation can be flexible enough to respond to market changes. NGPA ceiling prices are actually price floors, and pricing disparities among types of gas caused by the operation of the market would not, in Terrill's view, be as great as those caused by the NGPA.

Distribution companies generally do not favor total deregulation of gas prices. C. William Cooper of the United Distribution Companies argues for continued controls. He calls for continued controls on new gas past January 1, 1985, until new pipeline rate designs are put into effect. These new rates would be designed so that pipeline takes from a field would better reflect gas utility demand. Section 102 "new, new" gas should be decontrolled, while section 104 old gas should continue to be controlled. According to Cooper, raising prices for

²Since the term "new gas" is defined in the NGPA, several bills refer to gas first produced after the enactment of the new legislation as "new, new" gas.

old gas by decontrolling such gas would lower prices for new gas and discourage further development of and exploration for new reserves.

Consumer groups present a variety of viewpoints depending on the type of consumer, e.g., residential or industrial, represented by the group. Some examples are illustrative. Robert Eckhardt, representing the Consumer Federation of America, states that the NGPA was designed to create incentives for the exploration of new gas while holding down costs to consumers by controlling the price of old gas. Eckhardt urges the Congress to allow the NGPA to follow its schedule and not decontrol those categories of gas not slated for deregulation (old gas). Such a move would benefit only the largest producers of gas. Eckhardt further urges the Congress to review the NGPA carefully and decide whether it wants to extend controls after January 1, 1985.

Robert M. Brandon of the Citizen/Labor Energy Coalition recommends a price freeze to deal with gas problems. He further recommends slowing the NGPA rate of price escalation and pushing back the scheduled date for deregulation of new gas. He contends that decontrolling old gas will not lower the overall average price of gas. Accelerated decontrol of gas would cost consumers billions of dollars and increase inflation. Brandon states that the NGPA provides adequate incentives to explore for new gas so that decontrol is not justified by the need for more exploration.

On the other hand, Jack Elam, representing the Process Gas Consumers Group argues for total decontrol. He claims that the partly regulated, partly deregulated market under the NGPA distorts the exploration, development, distribution, and price of gas. All price controls should be removed on January 1, 1985. Any controls that are retained will only continue the market distortions of the NGPA and the NGA. Partial controls have resulted in excessive prices for section 107 gas and in a variety of troublesome contract terms. Thus, Elam sees deregulation as the best solution to current problems.

Gary S. Furman, representing the National Association of Manufacturers, also claims that the NGPA has created market distortions. The Act supplies less gas than would a free market. Its below-market ceiling prices for both old and most new gas discourage exploration. Furman also mentions the possibility of a price spike in 1985 when new gas is deregulated, due to the NGPA's low target price of \$15 per barrel of oil in 1985. Industry would be hit hard by such a spike. Furman states that a free market is the best allocator of scarce resources and calls for total, phased deregulation of gas by 1985.

Discussion

The wellhead pricing option that lets the gas market operate with the least distortion is probably total decontrol. But, under immediate, total decontrol, customers would pay billions of additional dollars to producers. Critics of total decontrol argue that not only is total decontrol unfair to consumers, but that it needlessly rewards producers of gas from old wells who expected price controls and that it results in little or no increase in the production and exploration of gas.

Partial decontrol proposals would not improve market efficiency, but would leave the parties as they stand. Proposals to extend or reimpose controls might keep the price of gas low for consumers, but could quickly lead to new shortages in a strong economy.

Even if total wellhead price decontrol were implemented, many of the existing market distortions would remain because of clauses in producer-pipeline and pipeline-distribution company contracts. Many legislative proposals have been introduced in the current session of the Congress that would either explicitly or implicitly alter pipeline contracts. These are discussed and analyzed in the next section.

Proposals Affecting Contract Provisions

The second major category of legislative proposal is those that would directly or indirectly modify contract provisions in the gas industry. There are several subcategories of legislative proposals that would affect these provisions. These include legislative proposals that would alter take-or-pay clauses; alter, create, or require market-out clauses; alter the effect of indefinite price escalator clauses, including most favored nation clauses and redetermination clauses; limit the guaranteed pass-through of prices called for in contract provisions; modify purchased gas adjustment clause operation; and alter the effect of minimum bill provisions. Each of these subcategories of proposal is discussed below. Included is some discussion of how proposals for altering each type of contract provision would help to solve distortions in the gas market.

In many cases, the proposed legislation would alter the guaranteed pass-through provision of the NGPA, which is discussed in chapter 2 and appendix C. The NGPA provides that the FERC may deny automatic pass-through on the basis of fraud, abuse, or similar ground, but it does not define these terms. Some bills dealing with contract provisions define fraud or abuse. If a contract provision is defined as an abuse for the purpose of the NGPA's guaranteed pass-through provision, the FERC can then determine that the price paid for the purchased gas is excessive and that the excessive portion of the amount paid is not to be passed through to the pipeline's customers. Thus, defining a contractual provision as an "abuse" for purposes of guaranteed pass-through would discourage the use of such a clause in a gas contract.

Take-or-Pay Clauses

Take-or-pay clauses in producer-pipeline contracts can cause distortions in the gas market. As discussed in chapter 3, such clauses can have the effect of giving pipelines an incentive to cut back on takes from producers of old gas when gas demand slackens in order to honor the take-or-pay provisions in new or high-cost gas contracts. Because gas demand has in fact slackened, the market distorting effects of take-or-pay provisions have already taken place. As a result, these contractual provisions are particularly controversial, and many of the legislative proposals introduced in the Congress would alter take-or-pay contract provisions.

Various legislative proposals have been introduced in the Congress to alter the effect of take-or-pay provisions in producer-pipeline contracts. Congressman Tauke's bill, H.R. 705, would create a rebuttable presumption that a contract is abusive, for purposes of guaranteeing pass-through of the gas cost, if the contract contains a take-or-pay clause between the pipeline and a non-affiliated producer with required takes greater than 50 percent of the daily contract quantity on an annual basis, or any take-or-pay provision between a pipeline and an affiliated producer. Congressman Volkmer introduced a bill, H.R. 910, defining take-or-pay clauses that require payment for gas not taken as abusive for the purpose of guaranteed pass-through. Senator Jepsen's bill, S. 239, would create a rebuttable presumption that a contract is abusive for purposes of guaranteed pass-through if the contract contains a take-or-pay clause that commits the purchaser to pay for more than 70 percent of the daily contract quantity whether or not the gas is taken. H.R. 796 and H.R. 873, introduced by Congressman Gaydos and Congressman Oberstar respectively, would provide natural gas pipelines with a volume adjustment option for any first sale of gas delivered before November 1, 1983. The volume adjustment option would allow the pipelines to

refuse any portion of the natural gas under contract without incurring an obligation to pay for gas not taken.

Several bills would make take-or-pay clauses unenforceable. Congressman LaFalce introduced a bill, H.R. 827, to amend the NGPA so as to prohibit the enforcement of take-or-pay clauses in any contract for the first sale or any subsequent sale of gas. Congressman Hertel introduced a bill, H.R. 1685, that would make unenforceable any take-or-pay clauses for the first sale of gas in any contract entered into on or after the enactment of the bill. The bill would also make any take-or-pay clause entered into before the enactment of the bill voidable at the election of the purchaser. However, the bill does provide that the FERC may provide, by rulemaking, an exemption from this bill's provisions voiding take-or-pay clauses if such take-or-pay clauses are necessary for the recovery of production costs or for the amortization of equipment and facilities used in connection with the delivery of natural gas to the purchaser. Congresswoman Collins introduced H.R. 2012, a bill that is similar to H.R. 1685. Her bill would also declare unenforceable take-or-pay clauses in contracts for the first sale of gas entered into after the enactment of the bill. However, her bill would make take-or-pay clauses in existing gas contracts also unenforceable. But, the bill would allow the purchaser to elect to either retain rights to receive gas not taken or receive a refund of amounts paid under the take-or-pay clause for which rights have not been exercised. Congressman Coleman introduced a bill, H.R. 1759, that would provide for a volume adjustment option allowing any purchaser to override a take-or-pay provision and elect to refuse delivery of any volume of gas without incurring an obligation to pay for the gas not delivered.

Other bills would reduce take-or-pay requirements to some maximum percentage, typically 50 percent, of contract volumes. Senator Kassebaum introduced a bill, S. 996, that would make any take-or-pay clause unenforceable during a three-year period beginning on the

effective date of the bill if the clause requires the pipeline to make any payment for gas in excess of 50 percent of the maximum annual volume for which the pipeline has contracted. H.R. 1752, a bill introduced by Congressman Addabbo, and S. 689, a bill introduced by Senator Heinz, would provide that all take-or-pay provisions in all contracts for the first sale of gas in effect on the date of the enactment of the bill are deemed to be limited to 50 percent.

Two identical bills endorsed by the NARUC Executive Committee, H.R. 2164 introduced by Congressman Tauke and S. 823, introduced by Senator Jepsen, would provide any present contract for the first sale of gas with a purchase requirement adjustment provision, unless otherwise determined by the FERC; the purchase requirement adjustment provision would override take-or-pay clauses by allowing a pipeline to refuse to take up to 50 percent of the contracted volume if the pipeline cannot market the gas. However, the bills provide that the purchase requirement adjustment would not apply if the FERC decides that the present contract is justified because of field drainage or casinghead requirements for gas produced with oil. Congressman Slattery introduced a bill, H.R. 2508, that would, during a three-year period beginning with the enactment of the bill, make take-or-pay provisions unenforceable if they impose take requirements upon the purchaser in excess of 50 percent of deliverable volumes. The bill provides, however, that this limitation on take-or-pay provisions will not apply to the first sale of gas associated with oil (casinghead gas) nor to stripper well gas. The bill also provides that the FERC is authorized to restore the enforceability of the take-or-pay requirements in a particular contract if this is necessary to prevent field drainage, reservoir damage, or prevent severe and irreparable financial injury.

The bills endorsed by the Reagan administration, H.R. 1760 and S. 615, provide that pipelines would have an option to reduce all take-or-pay clauses to 70 percent of deliverability, except when

higher takes are necessary to avoid flaring gas under those contracts that apply to gas produced in association with oil. The option to reduce take-or-pay provisions would expire January 1, 1986.

Other bills would have the FERC deal with take-or-pay clauses. Senator Kassebaum introduced a bill, S. 60, that would provide the FERC with the authority to rescind, annul, or modify contract provisions that the Commission determines are excessive, unjust, or unreasonable due to take-or-pay clauses. Senator Danforth introduced a bill, S. 291, that would suspend the operation of take-or-pay clauses unless the FERC finds the contractual arrangement, or some modification of it, to be in the public interest. In order to find a contractual arrangement to be in the public interest, the FERC must find that it was made before the enactment of this bill and that it (or some modification of it) is necessary either because of field drainage requirements or to prevent a default by the producer under a bank agreement or debt instrument.

H.R. 4, introduced by Congressman Michel, and S. 1049, introduced by Senator Hart, would provide pipelines with a market-out provision for any contract with a take-or-pay clause. These bills are discussed in the next subsection on market-out clauses.

Market-Out Clauses

Several of the bills shown in tables 4-1 and 4-2 contain provisions that allow pipelines either to "market-out" of existing contracts or to abrogate their existing contracts. Bills containing the more traditional type of market-out clause would have the virtue of solving the market ordering problems caused by high take-or-pay provisions, while often allowing the pipeline a right of first refusal on any renegotiated gas price. Other market-out clauses, with provisions drafted more broadly, would have the effect of abrogating

either a portion or all of existing gas contracts. Such clauses would allow the pipelines and producers to renegotiate their contracts so as to reflect the current market. These clauses would have the disadvantage of not permitting the pipeline and the producer to have what they bargained for initially.

One example of a legislative proposal that includes a market-out provision is a bill introduced by Congressman Michel, H.R. 4 (which is very similar to one previously introduced by Congressman Brown in the 97th Congress). The bill would amend the NGPA by facilitating price responsiveness during periods when supplies exceed demand. The bill provides a limited market-out clause to every natural gas pipeline company so that every company has the legal ability to reduce deliveries of its high-price natural gas to 50 percent of the contract volumes. If a pipeline exercises this limited market-out, the bill provides that the market-out must first be exercised, to its maximum extent, against its highest price sources of natural gas, and that the market-out provision cannot be exercised against any non-affiliated producers until the pipeline has exercised its market out, to its maximum extent, against affiliated producers that are delivering gas at the same or higher price.

Another bill, H.R. 705, which was introduced by Congressman Tauke, would encourage the use of market-out clauses by creating a rebuttable presumption that a contract is abusive for purposes of guaranteeing pass-through of purchased gas costs if the contract does not contain a market-out clause. H.R. 910, a bill introduced by Congressman Volkmer, is similar in that it would define as an abuse the absence of market-out clauses that allows a producer to escape the contract or negotiate a lower price if the gas is not marketable. Senator Jepsen's bill, S. 239, would also provide for a rebuttable presumption of abuse if a contract does not include a market-out clause.

As noted earlier, Congressman Hertel's bill, H.R. 1686, would exempt gas contracts from a price freeze if the contract contains a market-out clause.

Congressman Addabbo introduced a bill, H.R. 1752, which would include, by operation of law, a market-out provision in every contract for the first sale of gas. The market-out clause would give the original purchaser a right of first refusal at the price at which the seller has negotiated with another buyer.

Congresswoman Collins introduced a bill, H.R. 2012, which would deem every contract for the first sale of gas to include a market-out clause, called an adjustment clause to reduce purchase requirements. This clause would allow the purchaser of gas to refuse delivery of up to 50 percent of the gas that the purchaser has contracted to accept if the purchaser determines that he cannot market the gas. However, if a pipeline exercises this clause, it must first exercise it on the highest priced gas, and the pipeline must exercise the clause against its affiliated producers selling gas at the same or higher prices before it exercises the clause against non-affiliated producers. Also, H.R. 2012 does not limit the market-out to 50 percent of the contracted volume, and it provides the pipeline with a right of first refusal at a price that would be paid to another buyer. Senator Kassebaum's bill, S. 996, has provisions requiring a market-out clause somewhat similar to that of H.R. 2012. However, S. 996 would only read a market-out clause into a contract if it is not renegotiated at the request of the pipeline.

H.R. 2508, a bill introduced by Congressman Slattery, would grant a broad market-out authority to both the seller and purchaser during a one-year period beginning on the date of the enactment of the bill. The market-out authority would allow either party, at its sole discretion, to terminate its gas contract with respect to all, or any

portion, of the natural gas covered by the contract. This market-out authority would be applicable to any contract for new or high-cost gas, except one that warrants the taking of a specified amount of gas.

Several other bills provide that contracts contain market-out clauses. Senator Heinz's bill, S. 689, would provide for all new and high-cost gas contracts to include, by operation of law, a market-out clause. The clause can be exercised by either the seller or the purchaser. The bill also provides the purchaser a right of first refusal, at the price that the seller has negotiated with another buyer, should the clause be exercised by either party. Senator Sasser introduced a bill, S. 740, that would require every contract for the first sale of gas to include, within sixty days of the enactment of the bill, a market-out clause; otherwise, the contract would be unenforceable. The bill would not, however, require market-out clauses in old gas contracts that are subject to continued regulation. Senator Jepsen introduced a bill, S. 823, providing that any existing contract for the first sale of gas would include a market-out clause to allow the pipeline to escape the contract or to negotiate a lower price if the gas is not marketable at the contract price, unless the FERC determines otherwise. Senator Hart introduced a bill, S. 1049, that would provide for a market-out clause in any existing contract for high-cost natural gas if it includes a take-or-pay clause or an indefinite price escalator clause, unless expressly provided otherwise in any revision of the contract agreed to by the parties after the enactment of the bill.

Perhaps the most far-reaching market-out provision in proposed legislation is in H.R. 1760 and S. 615, the bills endorsed by the Reagan administration. These bills would give both the seller and the

purchaser in a contract for the first sale of gas the right to terminate the contract upon 45-days advanced notice.

Indefinite Price Escalator Clauses

Some analysts contend that an additional danger in the gas market is the possibility of fly-up due to various types of indefinite price escalator clauses. Several legislative proposals have been introduced in the Congress to address the problem of indefinite price escalator clauses generally and most favored nation clauses and redetermination clauses in particular.

While indefinite price escalator clauses that allow gas producers to receive the current market price at the time of sale create no market distortions in themselves, distortions can arise from the inflexibility that can be associated with most favored nation and oil parity clauses. This would be the case particularly if oil parity clauses do not accurately reflect the substitutability of fuels, leading to incorrect prices, and most favored nation clauses cause these incorrect prices to spread. The legislative proposals described here are aimed at solving this type of market problem.

Several bills, such as H.R. 705 and S. 239, would discourage the use of indefinite price escalator clauses in general by creating a rebuttable presumption that their inclusion in a contract is an abuse for the purpose of disqualifying pipeline gas cost pass-throughs to distributors and, ultimately, to customers. Another bill, H.R. 910, defines as an abuse the use of price escalator clauses tied to a price index that is not approved by the FERC as reliable.

H.R. 1685, a bill introduced by Congressman Hertel would provide that any indefinite price escalator clause that is entered into on or after the date of enactment of the bill is unenforceable, while any

price escalator clause entered into before the date of enactment of the bill is voidable at the election of the purchaser.

H.R. 2164, the bill endorsed by the NARUC Executive Committee, and S. 823 would void all indefinite price escalator clauses in contracts for the first sale of gas. The bills define an indefinite price escalator clause as any price provision that does not establish a specific unit price predictable with certainty over the duration of the contract. However, the indefinite price escalator clause will not be voided if the FERC so determines for good cause.

H.R. 1752, a bill introduced by Congressman Addabbo, and S. 689, a bill introduced by Senator Heinz, would also void indefinite price escalator clauses in all contracts for the first sale of gas. Another bill, S. 996, would also provide that any indefinite price escalator clause applicable to the first sale of gas is unenforceable. It defines an indefinite price escalator as any contract provision that provides for the establishment or adjustment of the price of gas by reference to the prices of gas in other contracts, crude oil, refined petroleum products, or any other commodity or any contract provision that the FERC determines to be comparable in form and result.

Senator Danforth's bill, S. 291, would suspend the operation of indefinite price escalator clauses unless the FERC finds the contractual arrangement, or some modification of it, to be in the public interest. The FERC must find that the contractual arrangement was made before the enactment of this bill and that the contractual arrangement is necessary either because of field drainage requirements or to prevent a default by the producer under a bank agreement or debt instrument.

The bills endorsed by the Reagan administration, H.R. 1760 and S. 615, would limit the operation of all price escalator clauses, in-

cluding indefinite price escalators, in contracts for the first sale of any gas except high-cost gas. The operation of price escalator clauses would be limited by a gas price cap, which is the volume-weighted average price of gas delivered under new and renegotiated contracts.

As shown in tables 4-1 and 4-2, some of the bills introduced in the current session of the Congress deal explicitly with most favored nation clauses or redetermination clauses. At least one of these bills, H.R. 705, would create a rebuttable presumption that a contract with a most favored nation clause is abusive for the purpose of disqualifying a pipeline's pass-through of gas costs to distributors. Certain other bills, such as H.R. 910 and S. 239, would also define the inclusion of such a clause in a contract as an abuse. H.R. 910 would also define the inclusion of a redetermination clause to be an abuse. H.R. 2508, a bill introduced by Congressman Slattery, would declare most favored nation clauses in any contract for the first sale of gas to be unenforceable.

Guaranteed Pass-Through

Many bills introduced in the Congress and listed in tables 4-1 and 4-2 would alter the provision of the NGPA that guarantees pass-through of purchased gas costs. These bills deal with guaranteed pass-through in order to limit the types of provisions that can be effective in producer-pipeline contracts or to make the terms in producer-pipeline contracts more sensitive to demand fluctuations in the gas market. Thus, these bills attempt to alter such provisions and terms indirectly.

One such bill is H.R. 705, introduced by Congressman Tauke. H.R. 705 would amend the NGPA by clarifying the term, abuse. The bill states that abuse (as used in section 601(c)(2) of the NGPA) includes

misrepresentation, imprudence on the part of the pipeline, failure by the pipeline to bargain at "arm's length" with any producer, and the entering into or carrying out of any producer-pipeline contract that materially prevents the pipeline from responding to changes in customer demand or other market forces. The bill then creates a rebuttable presumption that a contract is abusive if it is between a pipeline and a non-affiliated producer and contains a take-or-pay clause with required takes greater than 50 percent of the daily contract quantity on an annual basis, if it is between a pipeline and an affiliated producer and contains any take-or-pay provision, or if it contains an indefinite price escalator clause or a most-favored nation clause. There is also a rebuttable presumption that the contract is abusive if it does not contain a market-out clause.

Congressmen Gaydos and Oberstar introduced H.R. 796 and H.R. 873, respectively, which, as noted above, would create a volume adjustment option for the pipelines. The bills treat any failure by a pipeline company to exercise its volume adjustment option so as to provide its customers with the least-cost gas available under contract as "fraud, abuse, or similar grounds" for purposes of section 601(c)(2) of the NGPA. However, the gas acquisition cost will not be determined to be excessive for purposes of reviewing guaranteed pass-through if the FERC determines that the acquisition was justified due to field drainage requirements or peak-shaving demands.

Congressman Volkmer's bill, H.R. 910, would amend section 601(c) of the NGPA to define abuse for FERC use in determining whether prices paid for gas should be allowed and to deny pass-through of excessive gas prices that are the result of imprudence. The bill defines "abuse" as including in a contract a take-or-pay clause that requires payment for gas not taken, a redeterminate clause, a most favored nation clause, a renegotiation clause, or a price escalator tied to a price index that is not approved by the FERC as reliable. The bill also defines abuse as the absence of a market-out clause that allows a

purchaser to escape from the contract or negotiate a lower price if the gas is not marketable. The bill defines the term, imprudence, to include any action that is not in the public interest or that materially prevents a pipeline from responding to changes in customer demands or other relevant market forces.

Congressman Coleman's bill, H.R. 1759, would define abuse to include pipeline purchases of gas at an excessive price. The price would be considered excessive if it exceeds the price of any other gas under contract not delivered to the pipeline on that day but which could have been delivered. This provision would not apply if the acquisition is necessary to prevent waste or protect the correlative rights of a producer drawing gas from a common field worked by several producers.

H.R. 2164, the bill introduced by Congressman Tauke and endorsed by the NARUC Executive Committee, and S. 823, the identical bill introduced by Senator Jepsen, define abuse to include misrepresentation, imprudence on the part of the pipeline, and failure by the pipeline to bargain at arm's length with any producer. Abuse also includes entering into or operating under a producer-pipeline contract that materially prevents the pipeline from responding to market forces. The bill provides that a determination by the FERC that the pipeline has entered into a contract that constitutes an abuse will void the abusive contract provision. The bill also provides that a failure to exercise purchase requirement adjustment provisions will create a rebuttable presumption of abuse.

Senator Jepsen's bill, S. 239, also would clarify the definition of abuse in the NGPA. His bill provides that the term, abuse, is not limited to misrepresentation, but also includes any imprudence on the part of the pipeline by entering into a contract that prevents the pipeline from responding to changes in customer demand and other market forces. The bill provides that a rebuttable presumption is

created that a contract is imprudent if the contract contains any of the following clauses: a take-or-pay clause that commits the purchaser to pay for more than 70 percent of the daily contract quantity whether or not the gas is taken, an indefinite price escalator or redetermination clause that is not tied to a recognized and approved economic indicator, or a most favored nation clause. The bill also provides for a rebuttal presumption of imprudence if a contract does not include a market-out clause.

S. 60 also amends section 601(c) of the NGPA to make imprudence grounds for disallowing guaranteed pass-through of gas costs. The bill also provides the FERC with the authority to rescind, annul, or modify contract provisions under certain conditions. The conditions are fulfilled if the FERC determines that (1) the amount paid for gas is either excessive due to fraud, abuse, imprudence, or similar grounds or is unreasonable or unjust under section 4 or 5 of the Natural Gas Act, and (2) the amount paid is a result of any producer-pipeline contract that prevents the pipeline from responding to the demands of customers or to other market forces by requiring the purchaser to pay for a minimum daily contract quantity of gas whether or not the gas is taken. Senator Danforth's bill, S. 291, and Senator Kassebaum's bill, S. 996, also amend section 601(c) of the NGPA by including imprudence as grounds for disallowing a guaranteed pass-through.

Congressman Hertel's bill, H.R. 1685, would amend section 601(c) of the NGPA in order to include waste, imprudence, and actions not in the public interest as grounds for the FERC to disallow guaranteed pass-through of gas costs. The bill would also provide the FERC with authority to revise, annul, or mandate contract terms and provisions, if appropriate.

The strongest measure was in a bill introduced by Congresswoman Collins, H.R. 2012, which would amend section 601(c)(2) of the NGPA so as to prohibit the guaranteed pass-through of any increase in the cost

of gas. The bill would require the FERC to conduct an investigation and determine, after a hearing, that the gas acquisition leading to the proposed cost increase is just, reasonable, and in the public interest.

One bill, however, would alter the NGPA so as to make the pass-through of gas costs more lenient. H.R. 131, introduced by Congressman Gramm, would amend section 601(c) of the NGPA to allow a guaranteed pass-through of purchased gas costs unless the FERC determines that the amount paid was excessive due to fraud.

Purchased Gas Adjustments

A purchased gas adjustment clause is a clause in a pipeline's FERC approved tariff that allows legal wellhead price increases to flow quickly through to customers. As shown in tables 4-1 and 4-2, some bills have been introduced into the current session of the Congress to change how purchased gas adjustment clauses would work. These legislative proposals could indirectly alter the effects of producer-pipeline contracts by altering the regulatory environment in which these contracts operate.

H.R. 4 provides that the FERC would have to take into account a pipeline's opportunities to use the market-out provisions made available by the bill in any purchased gas adjustment clause proceeding. H.R. 796 and H.R. 873 require a pipeline to file a modification of cost under its purchased gas adjustment clause to reflect the use of the volume adjustment option provided to the pipeline under the bill. H.R. 1759 also provides for a modification of costs recovered by a pipeline through its purchased gas adjustment clause as a result of its compliance with the bill.

The bills endorsed by the Reagan administration, H.R. 1760 and S. 615, take a different approach. These bills would place a temporary limitation not only on the wellhead price of gas, but on the purchased

gas adjustments that pipelines could receive. Increases in the purchased gas adjustments of a pipeline would be limited by a factor reflecting monthly changes in the annual inflation rate. A pipeline would not be able to recover a higher average cost for purchased gas unless it files an application with the FERC and the FERC decides after a hearing that costs sought to be recovered were just, reasonable, and prudently incurred.

Minimum Bill Provisions

All the legislative proposals dealing with contract provisions described thus far deal with provisions of producer-pipeline contracts. The minimum bill provisions in pipeline-distribution company contracts also create distortions in the gas market that are similar to those created by take-or-pay clauses in producer-pipeline contracts. In addition, the existence of minimum bill provisions in pipeline-distribution company contracts might lessen the incentive of pipelines to engage in hard bargaining in producer-pipeline contracts because much of the risk associated with these producer-pipeline contracts is shifted forward to the distribution company. The proposals described in this subsection and listed in tables 4-1 and 4-2 address these concerns.

H.R. 2182, a bill introduced by Congresswoman Schroeder, would reduce the minimum bill requirements of distribution companies in order to allow gas to be acquired under the contract carriage provisions of the bill.

S. 996 would make any minimum bill provision unenforceable for more than 50 percent of the maximum annual contract volume. The bill would also make the minimum bill requirement unenforceable if the requirement does not entitle the purchaser who makes a payment under the minimum bill requirement to take subsequent delivery of the gas paid for.

Some legislative proposals deal with minimum bill provisions indirectly. H.R. 1685, for instance, defines take-or-pay clauses broadly so as to include sales of gas subsequent to the first sale. The bill would declare all such take-or-pay clauses to be unenforceable. The bill, thus, also would appear to make minimum bill provisions unenforceable.

The Positions of the Interest Groups³

The various interest groups representing producers, pipelines, distribution companies, and consumers again have different positions on the desirability of the legislative proposals to alter gas contracts. Producers generally believe that contract provisions should be left alone and not abrogated by the Congress. Nicholas Bush of the Natural Gas Supply Association stresses the importance of such contract provisions as indefinite price escalators and take-or-pay clauses in meeting the needs of producers and pipelines. Indefinite price escalators, in Bush's view, provide incentives to producers to explore and develop gas reserves while providing assurances to pipelines that they will pay only the market value for that gas. Without such clauses, the parties would be at the mercy of economic conditions unforeseen at the time the agreement was signed. Bush sees indefinite price escalators as necessary in order for the industry to continue to produce adequate supplies of gas.

Take-or-pay clauses are also important, according to Bush. Pipelines need to secure their long-term supply while ensuring that they have enough gas to meet their customers' short-term demands. Producers need steady incomes to pay costs and taxes and to provide collateral for loans. Take-or-pay clauses meet these needs and, according to Bush, do not mean that pipelines pay more money for less

³The discussion here is drawn from the material in footnote 1.

gas. Pipelines can operate with flexibility, increasing or decreasing takes as demand varies, while producers receive a steady income. Bush feels that current problems will work themselves out and they should not be the cause of any unneeded Congressional action. He claims that most of the criticism directed at take-or-pay clauses is due to the different ceiling prices that the NGPA has established for gas. He proposes that the Congress abolish those price categories instead of altering contracts.

Aubrey V. Hamilton of the Sun Gas Division of the Sun Exploration and Production Company states that pipelines demanded long-term contracts. According to Hamilton, pipelines needed a long-term commitment of supply in order to receive certification from first the Federal Power Commission and then the Federal Energy Regulatory Commission. Like Bush, Hamilton also stresses that long-term contracts guarantee revenue for producers. Falling gas prices show that contracts can respond to market pressures. Hamilton echoes Bush in urging the Congress to avoid passing legislation that would interfere with the operation of the producer-pipeline contracts.

While producers stress the benefits of the various contract terms, the representative of one interstate pipeline group discusses what he believes to be some potentially harmful effects. Jerome McGrath of the Interstate Natural Gas Association of America notes that most contracts covering gas to be deregulated in 1985 contain indefinite price escalators that could push the average price of interstate gas above market clearing levels. McGrath urges the Congress to pass legislation to defuse such provisions through a price cap and thus avoid a fly-up of gas prices in 1985.

In testimony in August 1982 before a House subcommittee, McGrath made no specific recommendations on take-or-pay requirements noting their importance in guaranteeing revenue to producers. Subsequently

(March 1983), however, McGrath advocated limiting take-or-pay requirements to 50 percent of deliverability.

George H. Lawrence of the American Gas Association voices a concern, similar to that of McGrath, that a fly-up in gas prices could occur due to indefinite price escalators. Such a fly-up would result in lost load, particularly among industrial and power plant customers. Lawrence calls for legislation to prevent such price increases. With respect to take-or-pay clauses, Lawrence states that very high percentages, such as 90%, led producers to increase deliverability so as to increase their revenues. At the same time, a field would be depleted more quickly. The most recent contracts have lower percentages, but the high percentages of older contracts could still present problems, especially if loss of customers were to become worse. Lawrence urges the Congress to keep the impact of take-or-pay clauses in mind when formulating policy, but he makes no more specific recommendations.

J.L. Terrill and Stan McLelland, representing the Coalition of Intrastate Pipelines, state that pipelines could benefit by being relieved of some of the obligations of take-or-pay. However, they note the importance of take requirements as a necessary bargaining chip that pipelines can use to secure new supplies from producers. Terrill plays down the problem of contract provisions in further testimony. In the view of intrastate pipelines, a more serious problem is the gas cushion enjoyed by interstate pipelines. Terrill believes that the inclusion of market-out provisions in an increasing number of contracts is an indication that the Congress need not take action in this matter. The Congress should be more concerned with wellhead pricing, he states. However, if any legislative action is taken on contracts, it should apply equally and bestow equal benefits to interstate and intrastate pipelines.

C. William Cooper of United Distribution Companies states that indefinite price escalators and favored nation clauses will force gas

prices far above market clearing prices and should be outlawed. Cooper urges legislation giving producers and pipelines the opportunity to renegotiate prices periodically. If no agreement can be reached, the contract should be terminable by either party, he believes. Cooper acknowledges the usefulness of take-or-pay requirements in that they can assure producers of revenue and protect against drainage of reservoirs. However, high take requirements, such as 80 or 90 percent, go beyond such reasonable ends. Cooper makes a recommendation similar to that for indefinite price escalators of periodic renegotiation and the right of a party to terminate the contract.

Stephen Schachman of Associated Gas Distributors also notes the possibility of indefinite price escalators forcing gas prices above market-determined levels upon decontrol in 1985. He urges legislation making such provisions unenforceable. Schachman also sees take-or-pay provisions that force pipelines to take large quantities of gas as a problem requiring legislative action. He recommends limiting take requirements to 50 percent. Schachman states that many pricing agreements will not result in market-determined prices upon deregulation in 1985. He feels corrective action is needed and urges the Congress to require market-out provisions in present and future pipeline-producer contracts.

As these positions demonstrate, the gas industry is divided on the contract provisions issue. Producers stress the benefits of various contract provisions, and pipelines, particularly interstate pipelines, are more likely to stress the problems stemming from contract provisions, particularly indefinite price escalators. Intrastate pipelines are more concerned with their perceived disadvantaged position vis-a-vis interstate pipelines. Distributors mainly stress the dangers of contract provisions and suggest their revision or abrogation.

Most consumer groups also stress the harmful effects of certain contract provisions. Robert Eckhardt, representing the Consumer Federation of America, urges the Congress to act before 1985 to prevent price escalators from forcing the price of gas above market clearing levels. He does not make a more specific recommendation, however.

Robert Brandon of the Citizen/Labor Energy Coalition counts take-or-pay and indefinite price escalator provisions among the causes of rising gas prices and detrimental effects on consumers. In his view, take-or-pay provisions serve mainly to boost prices above what the market can bear instead of merely protecting producers against the risks of their investments. Indefinite price escalators force prices above justifiable levels. Because of such escalators, utilities and consumers cannot be certain of the price they will have to pay for gas. Brandon recommends that the Congress remove both these types of provisions from contracts.

At least one industrial consumer group takes a somewhat different approach. Jack Elam, representing the Process Gas Consumers Group, blames any contract problems on the NGPA system of partial deregulation. He recommends voluntary renegotiation between producers and pipelines to settle their contract problems. Such an approach would be the one most in accord with the operation of a free market. At the same time, Elam urges the Congress to require all producer-pipeline contracts to be filed with the FERC and to be available for public inspection.

Discussion

Although the legislative proposals that directly address wellhead price controls handle many of the concerns about market efficiency, even immediate, total wellhead price decontrol would not be sufficient

to remove all the distortions in the gas market. As discussed in chapter 3, many of the distortions in the gas market originate from producer-pipeline contracts. Most of the bills introduced in the Congress address these market distortions by proposing to alter the contractual arrangements between producers and pipelines or between pipelines and distributors. These legislative proposals to alter contracts contain a wide range of proposals covering a variety of topics including discouraging or altering take-or-pay clauses, encouraging or requiring market-out clauses, discouraging or abrogating indefinite price escalator clauses, discouraging or abrogating most favored nation clauses, discouraging or abrogating redeterminate clauses, altering purchased gas adjustments, altering the effect of guaranteed pass-through, and altering minimum bill provisions. While these legislative proposals would correct one or more of the market distortions created by pipeline contracts, gas producers often oppose proposals to alter producer-pipeline contracts. The producers oppose altering these contracts because they believe it unfairly denies them the value of the contractual provisions that they bargained for with the pipelines. Without the contract provisions, many of the producers' wells might never have been drilled. The producers and their financiers relied on the validity of these contract provisions. To alter these contract provisions so as to take their value away from the producers, without compensation, after the wells are drilled may be inherently unfair.

Proposals Affecting Market Structure

While many of the legislative proposals concern wellhead price controls or gas contract provisions, a few of the legislative proposals change the basic structure of the market in the gas industry. These legislative proposals deal directly with the position of the pipelines in the gas market and seek to create a more competitive market with many buyers and many sellers. These proposals

fall into two categories, contract carriage proposals and common carriage proposals.

Contract carriage proposals would allow a pipeline to continue to operate as a regulated public utility serving its distribution companies by purchasing and transporting gas. However, the pipeline would be required also to transport gas it does not own on a nondiscriminatory basis with any of its available excess capacity from producers to buyers who have entered into a contract for the gas. The first subsection below describes such proposals.

Common carriage proposals would significantly alter the gas market by prohibiting pipelines from owning any of the gas they transport. As a common carrier, a pipeline would be required to carry gas on a nondiscriminatory basis from any producer to any buyer at a regulated transportation fee. In effect, common carriage proposals would allow only non-pipeline buyers and producers to contract directly with each other, eliminating the pipeline from the market as a buyer. These proposals are described in the second subsection.

Contract Carriage Proposals

Several of the legislative proposals shown in tables 4-1 and 4-2 would change the gas market by requiring a pipeline to provide contract carriage services to producers and buyers. One of the proposals is contained in H.R. 4, a bill introduced by Congressman Michel, which contains a very limited contract carriage provision. It provides every producer-pipeline contract with a transportation obligation clause unless the contract is entered into or signed after the bill passes and expressly rejects such a clause. The transportation obligation clause would require a pipeline to transport from a producer to a purchaser any gas that is not taken by the pipeline under the market-out provision of H.R. 4. The bill provides that the pipeline would receive just compensation for transporting the gas.

Congressman Addabbo's bill, H.R. 1752, and Senator Heinz's bill, S. 689, are similar to H.R. 4. They provide that any pipeline that exercises the market-out provisions provided by the bills and does not exercise its right of first refusal must transport the producer's gas on a best effort basis. The bills provide that the rate charged for transportation by the pipeline will be agreed to by the pipeline and producer. If no agreement can be reached, the rate will be set by the FERC or, in S. 689, by the appropriate regulatory authority.

H.R. 2508, a bill introduced by Congressman Slattery, would also require a pipeline that declines a right of first refusal offered by a producer under a market-out clause to transport the producer's gas on a best effort basis. However, this transportation obligation must not impair the pipeline's ability to render service to its existing customers nor have an adverse effect on high-priority customers. The pipeline would receive a rate for transportation service that is agreed to by the parties. If no agreement is reached, the FERC will determine the rate.

The bill endorsed by the NARUC Executive Committee, H.R. 2164, and its companion bill, S. 823, also contain a limited contract carriage provision, called a transportation obligation clause. This clause would create an obligation for a pipeline to transport gas involved in a purchase reduction through the pipeline's exercise of its purchase requirement adjustment provision if the gas is sold to a secondary buyer and the pipeline would otherwise have to pay for it. The bill also provides that the pipeline would receive just compensation for its transportation services, as determined by the FERC or for an intrastate pipeline by the appropriate state agency.

The bills endorsed by the Reagan administration, H.R. 1760 and S. 615, also contain a transportation obligation clause, which is linked to either party exercising the bills' market-out provisions for terminating the contract. If a contract is terminated, the pipeline

would have an obligation to transport the gas for the producer. However, the FERC or, in the case of intrastate pipelines, the appropriate state agency can limit the transportation obligation if it finds that compliance with the obligation would require the pipeline to construct additional facilities or would impair the ability of the pipeline to render adequate service to its existing customers. The pipeline is to receive just compensation for its transportation services; the expense is not to be flowed back to the existing customers of the pipeline.

Congressman Bedell's bill, H.R. 2054, is a more comprehensive contract carriage bill. It would require a pipeline to carry gas upon application by a producer or purchaser of gas unless the FERC makes certain findings. If the FERC finds either that the pipeline has no available capacity to carry the gas, that carrying the gas would place an undue burden on the pipeline, that construction of new facilities by the pipeline would be required to carry the gas, or that carrying the gas would impair the ability of the pipeline to render adequate service to its existing customers, then the pipeline need not carry the gas. The bill also provides that the FERC will establish a rate as just compensation for the transportation services. The amount received by the pipeline for transportation will not be required to be flowed through as a credit to the pipeline's customers.

Another bill, H.R. 2182, introduced by Congresswoman Schroeder, also contains broadly written provisions providing for contract carriage. It would require a pipeline to provide a producer or purchaser with transportation services if the pipeline has available capacity. These contract carriage requirements also would apply to a distribution company that purchases gas for resale to another distributor.

H.R. 2499, a bill introduced by Congressman Ritter, and S. 1017, a bill introduced by Senator Bradley, would require an interstate

pipeline with available capacity to transport gas for a seller or a purchaser who files a request with the FERC more than 90 days in advance. The current requirements of existing customers and high-priority users are to be protected in these bills. These bills provide for an incentive payment to an interstate pipeline that voluntarily agrees to transport the gas. The incentive payment will not be credited and flowed through to the interstate pipeline's customers. If, however, the pipeline contests the transportation of such gas and is ordered to transport the gas by the FERC, then the compensation received for transporting the gas will be flowed through to the pipeline's customers.

Senator Kassebaum introduced a bill, S. 996, that would require the FERC to order, upon application, any interstate pipeline to transport gas from a producer to a purchaser if the FERC finds that the pipeline has available capacity, that the transportation would place no undue burden upon the pipeline, that the transportation would not require the construction of new facilities, and that the transportation would not impair the ability of the pipeline to render adequate service to its existing customers or its future noninterruptible customers. The bill provides that the pipeline will receive just and reasonable compensation for the transportation. Under the bill, an affiliated producer cannot receive contract carriage.

Common Carriage

Two legislative proposals concern altering the pipelines' position in the market to that of a common carrier. Both H.R. 2565, a bill introduced by Congressman Corcoran and endorsed by the Illinois Commerce Commission, and Senator Dixon's S. 1119 would require pipelines to transport gas, without discrimination, on the reasonable request of the owner of the gas, as long as three conditions are met. One condition is that the owner of the gas provide the pipeline with

the required notice for a minimum volume of gas. A second condition is that the owner agrees to compensate the pipeline in accordance with the transportation tariff established by the FERC. The third condition is that the pipeline must have sufficient, available capacity. The available capacity is that portion of pipeline capacity, including compressor and looping facilities, which is available off-peak. The bill also provides that gas not obligated to any purchaser, called free access gas, may be sold to any buyer capable of taking delivery. H.R. 2565 provides that existing gas contracts that have not been renegotiated are voidable by pipelines or local distribution companies before January 1, 1985. Thereafter, these contracts are voidable by producers as well. S. 1119 would merely make existing contracts voidable by either the pipeline or the local distribution company if the contract contains a take-or-pay or minimum bill provision.

The Positions of the Interest Groups⁴

Representatives of producers, pipelines, distribution companies, and consumers do not agree about the desirability of altering the structure of the gas market by changing the position of the pipelines in the market to that of a contract or common carrier.

Jerome McGrath of the Interstate Natural Gas Association of America says that contract carriage is not a new idea in the natural gas industry. He states that many members of his association transport gas owned by others, but due to obligations to current customers and a lack of monetary incentives, contract carriage is not widespread. McGrath claims that his organization is not opposed to expanding contract carrier requirements. He states that the number of such agreements has been increasing. On the other hand, McGrath is opposed to the provisions of the Reagan bill (section 317(a)) that would require contract carriage under certain circumstances, but he

⁴Ibid.

approves of voluntary contract carriage with appropriate economic incentives such as those provided in section 317(b) of the Reagan bill. Such voluntary contract carriage would, in McGrath's view, result in more contract carriage than would compulsory legislation.

C. William Cooper of United Distribution Companies proposes a form of contract carriage. As noted earlier, Cooper proposes invalidating indefinite price escalators and high take-or-pay requirements, substituting periodic renegotiations between producers and pipelines. Each party would have the right to terminate the contract if no agreement could be reached in the negotiations. Cooper further proposes that if the producer terminates the contract, he may try to sell the gas to another pipeline. The pipeline that was the party to the terminated contract would retain the right of first refusal of the gas at the price offered by the producer to the new, prospective buyer. If the original pipeline decided not to take the gas at the new price, it would have to transport the gas to the new purchaser.

Stephen Schachman of Associated Gas Distributors states that making it easier for distributors to obtain transportation of gas purchased from suppliers other than their usual pipeline suppliers would better enable distributors to shop for gas and create some competition with pipelines at the wholesale level. Schachman notes that section 311(a) of the NGPA was intended to encourage pipelines to transport distributors' gas by eliminating certain certification requirements. However, regulations issued by the FERC under section 311 do not, Schachman claims, provide sufficient financial incentive to pipelines to transport the gas. He urges legislation requiring the FERC to provide such incentives to pipelines. According to Schachman, with proper financial incentives, pipelines should be required to carry a distributor's gas on a firm basis up to certain levels specified in the contract. Beyond those levels, the gas could be transported on an interruptible basis.

David W. Wilson of the Association for Equal Access to Natural Gas Markets and Supplies represents independent producers and users of natural gas. According to Wilson, his group's aim is to ensure that all producers, purchasers, and consumers of gas have access to markets and supplies to the extent currently enjoyed only by gas pipelines. His organization sees present laws and regulations as limiting access to gas markets. In Wilson's view, purchasing decisions should be made by gas users. Distributors and end users should be able to negotiate directly with producers, and purchasers must be able to have gas shipped to them.

Wilson advocates that certain types of gas be identified as available for sale by producers to any purchaser, with pipelines (both interstate and intrastate) being made common carriers required to transport the gas. The gas identified could include gas produced after a certain date, gas released from a contract under a market-out clause, or other category of gas. Wilson states that pipelines would have to be compensated fairly for their services with tariffs set in a manner similar to those of other common carriers, such as railroads. When a pipeline was carrying gas for others, it could be excused (via decertification) from its other service obligations. Wilson sees such common carrier status as producing a national market for gas.

Discussion

Although the legislative proposals that would result in pipelines becoming common carriers would probably result in the most efficient market because it would increase competition among many sellers and many buyers, pipelines tend to oppose this proposal because it would deny them much of the value of their business, which is to buy, to own, and to sell gas. Their opposition to common carriage is based on a conviction that a denial of the right to own gas would be an unfair

taking of a valuable property right. The pipelines also fear that for common carriage to work the FERC would need to become involved in the day-to-day operation of each pipeline, which would impinge upon their managerial prerogatives.

The contract carriage proposals involve less extensive changes than the common carriage proposals because contract carriage would allow the pipelines to continue to operate as public utilities that own the gas. Contract carriage might, nonetheless, create an effective spot market for gas. Such a spot market might be sufficiently large to make the gas market responsive to changes in supply and customer demand, while at the same time providing fair treatment to investors in the pipelines.

Other Proposals

A few of the legislative proposals address topics other than wellhead price controls, altering contract provisions, and altering the structure of the gas market. These are proposals such as modifying pipeline rate designs, limiting imports, and repealing the Fuel Use Act. These other proposals are discussed in the two next subsections: modifying pipeline rate designs in the first and miscellaneous proposals in the second.

Modifying Rate Designs

Several of the bills would require studies to modify gas rate designs. Congresswoman Dixon and Senator Cranston each introduced a joint resolution, H.J.Res. 58 and S.J.Res. 46 respectively, to require the FERC to commence a rulemaking relating to natural gas pipeline rate designs to ensure that rates reflect the market clearing prices in the service areas of local distribution companies.

A stronger bill, H.R. 482, was introduced by Congresswoman Byron. The bill provides that a gas distribution company, a state, a state public utility commission, or a municipality can file a complaint, under section 4(e) of the Natural Gas Act, that any rate proposed by an interstate pipeline company is not just and reasonable and that the rate, taken together with lawfully imposed charges for the retail delivery of the gas, results in a burner-tip price that is in excess of the Btu-equivalent price of the alternative fuel of existing retail customers. If such a complaint is made, the FERC would suspend the interstate pipeline's rate increase filing and hold a hearing on the matter. At the hearing, the interstate pipeline has the burden of proving that its gas purchase contracts and acquisition practices are designed to maintain burner-tip prices at a level competitive with alternative fuels and that its wholesale rates are and would be adjusted in response to increases and decreases in the retail prices of the alternative fuels. If the FERC finds that the interstate pipeline has failed to discharge its burden of proof, the FERC would prescribe an adjustment of rates for the pipeline company's service area to make prices competitive with the prices of alternative fuels. The interstate pipeline company's gas purchase contracts would then be deemed to include a provision relieving the pipeline of its obligation to purchase or pay for gas if, in the pipeline's sole opinion, the gas is not marketable in its service area. In effect, this bill would provide for a form of net-back billing, letting the feasible retail rate determine the wellhead price, if the burner-tip price of gas exceeds the price of alternative fuels.

Miscellaneous Proposals

Other proposed legislation contains miscellaneous provisions that address relatively minor problems in the gas market. H.R. 1760 and S. 615, the bills endorsed by the Reagan administration, H.R. 2164, the bill endorsed by the NARUC Executive Committee, and its companion

bill S. 823, would repeal both the incremental pricing provisions of the NGPA and the Powerplant and Industrial Fuel Use Act of 1978.

S. 512, a bill introduced by Senator Nickles, would also repeal the FUA. These bills would, thus, correct some of the demand ordering problems described in chapter 3.

Some analysts claim that the price and quantity of imported gas has caused gas prices to increase unduly. Some bills have provisions to limit the price or quantity of imported natural gas. S. 370, for example, would provide that the just and reasonable rate for regasified imported liquefied natural gas (LNG) cannot exceed the average price of number 6 fuel oil, unless the FERC and the Secretary of Energy determine that domestic supplies of natural gas are not available at a competitive price in the volume required in the area where the LNG is to be delivered, the source of supply of the imported LNG is reasonably secure from political and technical interruption, and the agreement under which the LNG is acquired includes a market-out provision to reduce the price or quantity of the imports should circumstance change. S. Res. 75, a resolution introduced by Senator Percy, states that it is the sense of the Senate that the Secretary of State, with the assistance of the Secretary of Energy, should immediately enter into negotiations with nations presently exporting gas to the United States in order to reestablish fair market conditions and lower prices for imported natural gas. H.R. 2012 would amend the Natural Gas Act to prohibit the import of natural gas, unless that gas is imported at prices that reflect the current market and unless such importation is determined by the FERC to be justified.

Some of the bills contain miscellaneous provisions that do not fit easily in any other category. H.R. 2012, for instance, contains authorizations for additional appropriations for low-income fuel assistance and weatherization. S. 60 contains provisions that would require the FERC to devise and put into effect an incentive rate of

return to stimulate the purchase of lower cost gas, consistent with gas availability and the need for a steady supply. H.Con.Res. 96, a concurrent resolution introduced by Congressman Whittaker, states that it is the sense of the Congress that the President should form a bipartisan National Commission on Natural Gas Pricing to make recommendations on natural gas pricing reforms to ensure adequate natural gas supplies and fair prices, and that the Commission should transmit its recommendations to the Congress in time for the introduction and passage of legislation before the next heating season.

Selected Bills of Interest to State Regulators

The first four sections of this chapter focus on the wide variety of legislative proposals that have been introduced in the Congress during the first six months of 1983. As this material is organized by type of proposal, no clear picture of any one bill may have emerged. In this last section, three bills that may be of special interest to state regulators are discussed. H.R. 1760 and its identical companion bill, S. 615, have been endorsed by the Reagan administration and are described first. H.R. 2164 is a bill that has been endorsed by the NARUC Executive Committee. H.R. 2164, together with its companion bill S. 823, is discussed next. H.R. 2565, a bill that has been endorsed by the Illinois Commerce Commission, is described in the third subsection below. The provisions of each of these bills are summarized in table 4-3.

President Reagan's Proposed Legislation

The Reagan administration has proposed legislation in the form of two bills that have been introduced in the Senate and the House of Representatives. These bills, S. 615 and H.R. 1760, provide that on or after the date of enactment any new contract may be signed and may operate according to its own terms. This would have the effect of

TABLE 4-3

SELECTED BILLS OF INTEREST TO STATE REGULATORS INTRODUCED IN THE CONGRESS DURING THE FIRST SIX MONTHS OF 1983*

BILL NUMBER AND ENDORSEMENT	CATEGORY OF PROPOSAL														
	PRICE CONTROLS			CONTRACT PROVISIONS								CARRIER STATUS		OTHER	
	Partial Decontrol	Total Decontrol	Extend/Reimpose Controls	Take-or-Pay Clauses	Market-out Clauses	Indefinite Price Escalators	Most Favored Nation Clauses	Redetermination Clauses	Guaranteed Pass-through	Purchased Gas Adjustment Clauses	Minimum Bill Provisions	Contract Carriage	Common Carriage	Modifying Rate Design	Miscellaneous
H.R. 1760 & S. 615 Endorsed by the Reagan Administration		X		X	X	X				X		X			X
H.R. 2164 & S. 823 Endorsed by the NARUC Executive Committee				X	X	X		X				X			X
H.R. 2565 Endorsed by the Illinois Commerce Commission													X		

Source: NRRI Staff

*Columns without entries are included in the table to facilitate comparison with tables 4-1 and 4-2.

immediately decontrolling any new, new gas--gas for which the first sale occurs after the enactment of the bill. The bill also provides that any existing contract may be renegotiated and may operate by its new terms. These provisions allow for the decontrolling of both "old, new gas" (i.e., NGPA section 102 and 103 gas sold under an existing contract) and old gas.

The Reagan bill further provides that, on January 1, 1985, for any contract that has not been renegotiated, either party may abrogate the contract unilaterally. If the contract is abrogated, the pipeline must carry gas for the producer to any other purchaser. The pipeline is granted an incentive rate for carrying the gas. The bill provides that all buyers have equal access to offshore and interstate gas. The FERC can require, on application, a pipeline with available capacity to carry, at an incentive rate, gas under contract from a producer to a purchaser. This sets up a partial contract carriage arrangement.

Under this bill, the wellhead price for the first sale of gas is no longer controlled under the NGA or the NGPA either on January 1, 1985 or upon renegotiation, whichever is sooner. Furthermore, the bill apparently exempts all transactions relating to the first sale of gas from federal regulation, including contract provisions.

In addition, the bill provides pipelines with an option to reduce all take-or-pay contract provisions to 70 percent of deliverability, except when higher takes are necessary to avoid flaring gas under take-or-pay contracts that apply to gas produced in association with oil. The option to reduce required take-or-pay percentages expires January 1, 1986. If the option is exercised, the producer may abrogate the contract and sell the gas elsewhere. In that event, the pipeline must transport the gas at an incentive rate. Also, no pipeline may take gas from its own production or from any affiliate at a rate higher than its rate of take for any less expensive gas.

Pending renegotiation, the maximum lawful price for gas under existing contracts for all categories of price-regulated gas is the lower of the NGPA ceiling price and the "gas cap." The gas cap is the volume-weighted average of the natural gas prices in all new contracts and all newly renegotiated gas contracts. The bill provides that the most recent gas cap is the rate for area rate clauses. Also, all contract escalator clauses that continue in effect from before the enactment of the bill are limited in operation by the gas cap. This limitation continues until January 1, 1986.

The bill provides that, until January 1, 1986, an interstate pipeline may not automatically pass through a weighted average gas cost greater than its last such cost, prior to the passage of the act, adjusted for inflation. For any additional costs to be passed through, they must be specifically approved by the FERC after a public proceeding.

The Reagan bill also provides for the immediate repeal of both the FUA and the incremental pricing provisions of the NGPA. It also repeals section 122 of the NGPA, which grants the President or the Congress standby authority to reimpose price controls.

Because S. 615 has been the subject of hearings, the positions of various interest groups on the Reagan bills have begun to emerge.⁵ The statements of representatives of some of the major interest groups are instructive. Nicholas Bush of the Natural Gas Supply Association states that his group supports the bill's goal of deregulation, but he believes that the bill contains some provisions that might hinder the transition to a deregulated market. For example, the inclusion of all

⁵The discussion that follows is drawn from material in U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce, "Testimony of Nicholas J. Bush." 98th Cong., 1st sess., March 24, 1983 (to be published); and "Statement of Jerome J. McGrath," op. cit.

gas contract negotiations in setting the gas cap would distort the cap, which according to Bush should reflect actual market conditions to the fullest extent possible. Renegotiated contract prices do not reflect arm's length negotiations; rather, they are shaped by the context of the existing contract and may not reflect actual market conditions.

Bush feels that the pipeline pass-through limitation is too inflexible and may hinder efforts by pipelines and producers to renegotiate contracts. He states that the proposal makes no allowance for the replacement of old, low cost gas by new, higher-cost gas as the old gas is depleted. Bush proposes allowing a pass-through of increased prices paid under new and renegotiated contracts as long as the average of a pipeline's new and renegotiated contract prices does not exceed the gas cap. He feels that the pass-through limitation must adjust to changing market conditions.

As noted above, Bush agrees with the deregulation objective of the bill. Deregulation must not, in his view, be postponed beyond the dates specified in the bill. He supports deregulation of gas that was not to be deregulated under the NGPA, so that all gas prices can reach the market level.

Jerome McGrath of the Interstate Natural Gas Association of America also objects to limitations on pipeline pass-through of costs. He claims that this limitation hurts those pipelines with the most low-cost gas. Such pipelines will need to buy high-cost new gas as their old gas supply is depleted. However, under the bill's provision, a pipeline can automatically recover costs only at the pre-enactment level of its purchased gas adjustment (PGA) plus an inflation adjustment calculated on the basis of the pre-enactment nationwide average PGA. Applications for pass-through above this

level are subject to FERC review and approval, and McGrath claims that pipelines with greater quantities of low cost gas will need to go through this review process more often since they will need to buy more high cost gas. These pipelines will be at a disadvantage in competing for new gas since pipelines with more higher-cost gas in their pre-enactment PGAs will be able to offer producers a higher price for gas without having to obtain FERC approval. McGrath proposes that automatic recovery of the cost of "new, new" gas be permitted as long as such costs are below 110 percent of the national gas cap price.

Legislation Endorsed by the NARUC Executive Committee

The NARUC Gas Committee drafted and the NARUC Executive Committee endorsed legislation that would restrain natural gas price increases by facilitating price responsiveness during periods when supplies exceed demand, and that would enhance competitive options for local distribution companies by allowing them to purchase and receive less costly gas. The legislation, introduced as H.R. 2164 and S. 823, would also clarify the definition of abuse as used in section 601(c) of the NGPA and would repeal the incremental pricing provisions of the NGPA.

These bills provide that indefinite price escalator provisions would be void in any present or future contract for the first sale of gas, unless otherwise determined by the FERC. The bills also provide that any present contract for the first sale of gas would be deemed to include a purchase requirement adjustment provision, unless otherwise determined by the FERC. The purchase requirement adjustment provision would permit a pipeline to exercise a right to refuse delivery of any portion of the volume of gas the pipeline has contracted to accept without incurring an obligation to pay, if the pipeline has determined that it cannot market the gas. In exercising the purchase requirement adjustment provision, the pipeline may not reduce the volume of gas

that it accepts below 50 percent of the volume that the pipeline has contracted to take. The pipeline cannot exercise the purchase requirement adjustment provision for a quantity of gas unless it has exercised the provision to the maximum extent permitted for all higher priced gas. The provision cannot be exercised against a non-affiliated producer unless it has been exercised, to the maximum extent permitted, against all affiliated producers. The purchase requirement adjustment cannot be applied to gas for which the FERC decides that the present contract is justified because of field drainage or casinghead requirements. A failure to exercise the purchase requirement adjustment creates a rebuttable presumption of abuse under section 601(c) of the NGPA.

The NARUC-endorsed bills provide that any present or future contract for the sale of gas includes a transportation obligation clause. This clause creates an obligation for any pipeline to transport gas if it exercises a purchase requirement provision to reduce gas takes on the grounds that it cannot market the gas. This obligation to transport extends to any volume of the gas that is involved in the reduction and resold by the producer to another purchaser if the pipeline would have been required to pay for it in the absence of the reduced take. The bill provides that the pipeline is to be compensated for transporting the gas.

In addition, the bill provides that local distribution companies would be encouraged by the FERC to seek the least expensive supply of gas from pipelines, producers, and others. A pipeline is prohibited from discriminating between its own gas and that of others in providing transmission, storage, and brokerage services for the local distribution companies.

Under the bill, all present and future first-sale contracts would be filed with the FERC, and reasonable public access to the contracts

would be required. The bill also provides for the repeal of incremental pricing under Title II of the NGPA.

Legislation Endorsed by the Illinois Commerce Commission

The Illinois Commerce Commission published a report in March 1983, entitled The Consumer Access Plan: Natural Gas Pipeline Common Carriage.⁶ In this report, the Illinois Commerce Commission endorsed a "Consumer Access Plan" which would immediately make the natural gas interstate pipelines common carriers; declare null and void all existing pipeline-distributor contracts, and sole supplier and minimum bill clauses; eliminate pipeline obligations to purchase gas for distributors; authorize the FERC to establish new common carrier obligations and transportation and storage tariffs for pipelines; direct the U.S. Department of Justice to report to the Congress on the adequacy of competition under existing pipeline vertical integration; declare all new gas and gas not under contract as "free access gas," which may be purchased by distributors and transported under tariff by the pipelines; require that by January 1, 1985 either party to a gas contract may abrogate the contract; and, authorize the FERC to require pipeline interconnections and system extensions.⁷ In April 1983, Congressman Corcoran introduced a bill, H.R. 2565, that contains the provisions of this access plan.

As mentioned, H.R. 2565 would require interstate pipelines and intrastate pipelines engaged in or affecting interstate commerce to transport gas upon the reasonable request of the owner of the gas if the pipeline has sufficient available capacity. The carrying pipeline would be paid in accordance with tariffs established by the FERC.

⁶Illinois Commerce Commission, The Consumer Access Plan: Natural Gas Pipeline Common Carriage (State of Illinois, 1983).

⁷Ibid., p. 7.

These rates would be designed to compensate the pipeline reasonably for expenses incurred. However, the costs or expenses of unused facilities would not be included in these rates unless the FERC specifically finds that the public interest requires inclusion. In establishing rates, the FERC is to take into account the lower costs associated with usage during off-peak periods and is to provide separate rates for interruptible service.

The bill also provides that the FERC will prescribe regulations governing the contractual relationships and obligations relating to the transportation of gas. Pipelines would be allowed to transport gas, their own or their affiliate's, under the same restrictions applying to other owners of gas. However, the maximum capacity reserved for the pipeline's own use is the lesser of the current and future capacities needed to serve all the pipeline's customers. The bill also provides that the FERC may require pipeline interconnections, extensions, or modifications of facilities if it determines that this is required by public convenience and necessity.

Under H.R. 2565, free access gas may be sold to any purchaser capable of taking delivery. The seller of free access gas would be released from all duties and contract obligations. Free access gas would include gas from wells for which drilling began after May 12, 1983; gas not subject to a sales contract on the date of enactment of the bill; gas released by the exercise of a market-out clause; gas subjected to a material unilateral modification of the sales contract by the pipeline; gas under a contract that is materially breached by the pipeline; and gas subjected to a termination of contract according to the bills' market-out provision. The bill also provides that contracts in effect on the date of the enactment of the bill, which are not subsequently materially amended or renegotiated, are voidable upon 60-days notice.

In addition, H.R. 2565 provides that the FERC and the Department of Justice must undertake a cooperative study on the effects of vertical integration in the gas industry.

CHAPTER 5
A REVIEW OF CITY-GATE PRICE FORECASTS

The previous chapter presented the variety of federal legislative proposals that have been put forth for dealing with natural gas wellhead price regulation and market distortions. Of particular interest to state regulators is the likely effect of various federal and state pricing policies on local distribution company rates. To examine the consequences of such policies on end-user prices, a two-step procedure was adopted for this study. The first step was to review the price forecasts that have been made by reputable national organizations such as the U.S. Department of Energy (DOE) and the American Gas Association in order to obtain forecasts of city-gate prices under various conditions. This initial step is described in this chapter. The second step was to formulate an equilibrium model of end-user prices at the distributor level. This model and the retail rates that result under various conditions are described in the next chapter.

Three natural gas market forecasting models and their price forecasts are reviewed in this chapter. These are the U.S. Department of Energy's Midterm Energy Forecasting System (MEFS), ICF's Two-Market model for natural gas, and the American Gas Association's TERA model. These models have been used to produce a variety of natural gas studies, four of which are discussed here. Each of these models contains a detailed description of supply conditions at the wellhead level and similarly has a fairly complete representation of demand elasticities by consuming sector and region. The transmission and distribution portion of the gas industry, however, is inadequately modeled with constant cost per unit. That is, the regulated pipeline and distribution cost is considered to be entirely variable, when in reality much of it is fixed.

The partial equilibrium model of a single natural gas distributor presented in chapter 6 of this report has a more accurate rendering of the fixed and variable components of a distributor's cost. The NRRI, however, could not incorporate this model of a distributor into a national energy supply and demand context in the time allotted for this study. Consequently, we rely on the above-mentioned three national models for city-gate price projections and improve upon the modeling of the regulated cost allocation process at the distribution level in arriving at final, burner-tip prices. Our equilibrium model of a distributor consequently has a partial equilibrium nature in that the city gate-price is taken as given. In reality, the regulated allocation of the distributor's fixed cost would itself affect the national market-clearing price of natural gas. Any such effect is likely to be quite minor, however, and is ignored in this study.

The three models are described in the first section, and the projected city-gate prices are presented in the second section of this chapter.

Three Price Forecasting Models

Several factors were important in selecting price forecasting models for this study. Any model should have adequate regional and sectoral disaggregation, a balance of supply and demand, consistency with other reputable economic and energy projections, and a sufficiently rich set of legislative and policy alternatives. Three models in particular appear to fulfill most of these requirements. These are the DOE's Midterm Energy Forecasting System, ICF's Two-Market model for natural gas, and AGA's TERA model. Four studies that were based on these models are of particular interest here. MEFS is used, in part, to produce DOE's Annual Report to Congress, the 1981 version of which (ARC81) has been used by the NRRI for this

study.¹ MEFS has also been used to study alternative decontrol policies for natural gas by the Energy Information Administration (EIA) of the DOE, which can be termed the EIA study.² In a study for the DOE, ICF used its Two-Market model to study various decontrol plans, which we will call the ICF study.³ The fourth study was conducted by the AGA using the TERA model primarily to determine the effects of indefinite price escalator clauses; however, the AGA study also examines the consequences of a policy of complete decontrol as well as that of following the NGPA.⁴

Each of these models has a supply and demand equilibrium representation of the natural gas market by region and by end-use sector. In addition, each has been used to forecast prices under a variety of policies to decontrol the natural gas market. These include actions to decontrol more quickly, more slowly, and at the same pace as currently planned in the NGPA. Also, they have been used to study the effects of indefinite price escalation clauses, of the Fuel Use Act of 1978, and of different projections of oil prices. The resulting range of price forecasts should be a good indicator of the uncertainty that surrounds the price of natural gas, particularly in 1985 when many categories are decontrolled.

¹See the Energy Information Administration, U.S. Department of Energy, 1981 Annual Report to Congress, DOE/EIA-0173/(81) (Washington, D.C.: 1981).

²See the Energy Information Administration, U.S. Department of Energy, Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices, DOE/EIA-0303 (Washington, D.C.: 1981).

³See Office of Policy, Planning and Analysis, U.S. Department of Energy, A Study of Alternatives to the Natural Gas Policy Act of 1978, DOE/PE-0033 (Washington, D.C.: 1981).

⁴See American Gas Association, "Consumer Impact of Indefinite Gas Price Escalator Clauses under Alternative Decontrol Plans," Energy Analysis (Washington, D.C.: November 6, 1981).

All three models determine a market equilibrium based on macroeconomic assumptions and world oil price projections. The differences between projections stem from the assumptions made in each model about the level of macroeconomic activity, world oil prices, policy choices, specific gas curtailment mechanisms, and demographic movements.

Macroeconomic Assumptions and World Oil Price Scenarios

The assumptions made in each model about the growth of macroeconomic activity affect the natural gas market and, in particular, the demand for natural gas. The projection of world oil prices is crucial. It is an important determinant of the difference between a market clearing price and the gas price administered under the NGPA, because of the potential for fuel switching by large industrial users. The resulting price level, in turn, determines such matters as the wealth transfer between producers with a large gas cushion and those with no gas cushion, whether gas prices are likely to jump in 1985 as new gas is decontrolled, and the magnitude of the wealth transfer from consumers to producers.

In general, all three models contain moderate assumptions about the growth rate of real GNP, industrial production, population, and the overall price level. The projections used by MEFS are slightly lower than those used by the other two. For example, real GNP is assumed to grow at 2.7 percent annually from 1980 to 1995 in MEFS, while 4.0 percent is assumed in the TERA model.

The following table lists the world oil price projections for three of the studies. Table 5-1 indicates that world oil price predictions are higher in ARC81 than in the other two studies. This is partially because ARC81 preceded the other two studies. Since then, oil prices have decreased, and most observers are predicting future oil prices much lower than were expected two years ago.

TABLE 5-1
WORLD OIL PRICE PROJECTIONS
IN THREE STUDIES
(1980 \$/bbl)*

Year	ARC81			IGF Study			AGA Study
	Low	Med	High	Low	Base	High	
1980	34	34	34	34	34	34	---
1985	26	33	38	31	35	40	30
1990	35	49	60	34	41	47	33
1995	49	67	88	38	38	55	37
2000	50	75	100	42	55	63	41

Data Sources: 1. 1981 Annual Report to Congress, op. cit.
2. A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit.
3. "Consumer Impact of Indefinite Gas Price Escalator Clauses under Alternative Decontrol Plans," op. cit.
*Dashes signify that the data are not available.

Federal energy programs impose some restrictions on the future natural gas demand, supply, and prices. In each study, the current NGPA provisions are imposed, and the case with these provisions serves as a reference scenario. Additional demand restrictions are provided by the Fuel Use Act, incremental pricing, and some curtailment programs. The effect of easing the Fuel Use Act is explicitly examined in the EIA report Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices using MEFS.

Model Structure

All three models have national energy market representations and can be used to analyze energy prices, supplies, demands, and conversion activities. The basic framework consists of three major components: demand model(s), supply model(s), and an equilibrating

mechanism that balances supply and demand. While the Two-Market model and the TERA model are partial equilibrium models focusing on natural gas market equilibrium, MEFS has a more general equilibrium nature. It takes into account the supply and demand conditions in all energy industries and the possible interactions among them so that a multiproduct equilibrium can be achieved.

The demand for natural gas and other energy products is estimated econometrically or by using engineering end-use representations based on assumptions about macroeconomic activity and world oil prices. The nature and extent of conservation programs are also considered. Given initial macrovariables and fuel price projections, the demand models determine quantities consumed and price elasticities in each region. These quantities and elasticities are included in the integrating model that finds a market equilibrium.

Demands are calculated for each of the major consuming sectors: residential, commercial, and industrial. Transportation and electric utility sectors are not included in all the models. The MEFS and TERA models have relatively greater regional detail in comparison to the Two-Market model. Ten federal energy regions are used in MEFS, nine census regions in the TERA, while only two markets (Southwest and the rest of U.S.) are included in the Two-Market model.

The forecasting of natural gas supply also draws upon econometric and engineering relationships relevant to domestic natural gas production. Given the assumption that individual producers seek to maximize their profits, gas production is determined by the production capacities, competitive fuel prices, contract clauses, and changes in economic and regulatory environments. Total natural gas supply is separated into several sources. The unique economic, regional, and supply engineering process associated with each particular natural gas source is included in each model segment. The Two-Market model has a detailed analysis of the supply of each natural gas source. In

addition to domestic gas supply, domestic old gas cushion and imports are estimated and included in the integration model. Overall, the supply system in each model includes imports, production, conversion, and transportation activities.

The integration portion of each model consists of an equilibrating mechanism that balances the supply and demand of natural gas under existing regulations. Note that in a general equilibrium model such as MEFS, other markets are in equilibrium simultaneously. Because of this, MEFS has the capability of linking the natural gas market with other energy markets. The Two-Market model and the TERA model can be modified to accommodate multiple sources of supply, multiple final demand sectors, differentiated transmission/distribution activity and costs, and various ways of determining price. Whenever demand exceeds available supply, an administered market equilibrium can be simulated. For example, the Two-Market model's data base has a rationing scheme to allocate the insufficient supply.

Two points should be noted about the natural gas market equilibrium. First, several economists have emphasized that, to analyze equilibrium in the gas market, one has to start at the burner tip and look at the uses of gas and its competition with alternative fuels. The price of gas at the burner tip is likely to be determined by competition with some form of fuel oil. In their view, the average price at the wellhead will equal the burner-tip price net of transportation costs and will, therefore, be insensitive to differences between partial and total deregulation. Second, none of these models considers the feedback effect of natural gas deregulation on the world oil market. Ott and Tatom argue that decontrol allows gas prices to rise, providing an incentive to boost domestic gas production and displace some U.S. and world oil with U.S. gas, further reducing the demand for OPEC oil and putting downward pressure on its price. If the effect of natural gas decontrol on the world oil

market is taken into account, the sudden price jump and its adverse affects in the year of decontrol may be substantially overstated.⁵

Pricing Forecasting under the NGPA and Medium World Oil Price Scenario

The following discussion highlights the detailed projections of natural gas consumption, production, and prices. From those reported in table 5-1, the medium oil price scenario of ARC81 and the base case in the ICF study serve as reference cases. Table 5-2 depicts the national supply and demand natural gas balance as projected in the reference cases of the three studies.

TABLE 5-2
SUPPLY-DEMAND BALANCE
IN THREE STUDIES
(QUADS/YEAR)*

Year	ARC81	ICF Study	AGA Study
1980	19.8	----	15.4
1982	----	19.4	16.6
1984	----	18.7	17.1
1985	18.8	19.1	15.7
1990	18.3	19.7	17.0
1995	19.1	----	----

Data Sources: 1. 1981 Annual Report to Congress, op. cit.
2. A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit.
3. "Consumer Impact of Indefinite Gas Price Escalator Clauses under Alternative Decontrol Plans," op. cit.
*Dashes signify that the data are not available.

⁵See M. Ott and J.A. Tatom, "Are There Adverse Inflation Effects Associated with Natural Gas Decontrol?" Contemporary Policy Issues, November 1, 1982. Their argument, outlined above, implicitly assumes the natural gas market does not achieve an equilibrium under rolled-in prices, as described in chapter 3 of this report. If an equilibrium were reached and decontrol occurred subsequently, consumer prices would rise, demand for natural gas (and therefore overall supply) would decline, and if oil and natural gas are substitutes, the demand for oil would increase and not decrease as suggested by Ott and Tatom.

Note that prior to the deregulation of prices under the NGPA a marked decline in gas production is projected by both the ARC81 and ICF studies. Production is projected to continue its decline for the period of 1985-90 by ARC81 and is unable to regain its 1980 level even 10 years after deregulation. The ICF study projects a faster rate of increase in production from 1984 onward and the 1982 level of production is once again reached in 1990. The AGA study projection is completely different. Production increases steadily before the year of deregulation, declines by 1.4 quads (8 percent) during the year of 1985, and increases thereafter.

The difference in production level projections between the two DOE studies and the AGA study stems from different specifications of production capability which, in turn, depend largely on the future success of new exploration. A falling trend for the ratio of conventional gas proven reserves to production, coupled with the diminished demand for natural gas, causes the ARC81 study to project a declining gas demand-and-supply balance through 1985. The ICF study finds that these trends are reversed after gas is decontrolled in 1985. Decontrol reduces consumption and expands unconventional gas production. The net result is a reattainment by 1987 of 1981 levels of supply. The AGA study projects conventional, lower-48 supplies to decline; however, this is offset by an expansion of domestic supplemental supplies (Alaskan gas, synthetic, and new technologies).

The declining production as projected in the ARC81 and ICF studies is inconsistent with the essentially steady gas production that has been observed during the past four years under gas price regulation and with the increase in proven reserves that has recently occurred. Moreover, other observers project a much smaller decline in production in the early 1980s under the NGPA than do these two

studies.⁶ Thus, in view of recent production and exploration, supply estimates in future studies with MEFS and the Two-Market model are likely to be revised upward.⁷

Because of reduced supply and gas pricing policies at the wholesale and retail levels before 1985, some unsatisfied demand exists in the market. Those customers with a low priority, principally those with large industrial boilers, are forced to substitute oil for gas. Decontrol in 1985 increases production as projected by the ICF and AGA studies and brings supply and consumption into a price-driven balance. Unsatisfied demand disappears through the adjustment in natural gas prices.

Table 5-3 summarizes natural gas prices projected by each study. All three studies project natural gas prices to increase significantly by 1985. Much of this increase occurs in 1985 when the prices of certain categories of gas are deregulated by the NGPA. Both the ICF and AGA studies project that the national average wellhead price will increase by more than 50 percent during 1985. While the national average wellhead price increases by more than 120 percent from 1980 as projected by ARC81, the increase is even larger according to the AGA study. It projects that the wellhead price will increase by about 230 percent from 1980 to 1985. Wellhead prices, however, are projected to increase at a declining rate by the AGA study, averaging

⁶See Appendix C, "Macroeconomic Consequences," A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit., Vol. III, p. 53, in which Wharton Econometric's estimate of U.S. gas production in 1984 under the NGPA is over 10 percent higher than the Two-Market's estimate, even though wellhead prices are assumed to be somewhat lower.

⁷Indeed, the DOE recently revised its own estimates for 1985 upward by 1.1 trillion cubic feet, or about 6 percent. See Office of Policy, Planning, and Analysis, U.S. Department of Energy, Energy Projection to the Year 2000, July 1982 Update (Washington, D.C.: August 1982), pp. 5-11.

TABLE 5-3
PROJECTED NATURAL GAS PRICES
(1980 \$/mcf)*

	1980	1982	1984	1985	1990	1995
<u>ARC81</u>						
<u>Wellhead Prices</u>						
Intrastate	--	--	--	4.58	6.40	7.23
Old Gas	--	--	--	2.98	2.96	2.95
New Gas	--	--	--	3.60	6.84	8.13
National Average	1.50	--	--	3.33	6.02	7.63
<u>City-Gate Prices</u>						
	--	--	--	5.32	7.19	8.07
<u>Retail Prices</u>						
Residential	--	--	--	5.40	7.43	8.73
Commercial	--	--	--	5.19	7.26	8.57
Industrial	--	--	--	4.38	6.40	7.65
Electric Util.	--	--	--	4.83	6.84	8.30
<u>ICF Study</u>						
<u>Wellhead Prices</u>						
Average Domestic	--	2.27	2.61	4.45	5.35	--
New Gas	--	3.03	3.28	--	--	--
Marginal	--	6.56	6.93	6.76	6.21	--
<u>City-Gate Prices</u>						
Interstate	2.57	3.16	--	5.37	6.14	--
Intrastate	2.11	2.43	--	5.23	6.02	--
<u>Retail Prices</u>						
Residential	--	4.31	4.83	6.59	7.36	--
Industrial	--	3.15	3.50	5.00	6.37	--
<u>AGA Study</u>						
<u>Wellhead Prices</u>						
National Average	1.53	2.56	3.33	5.04	4.18	--
<u>Retail Prices</u>						
Residential	3.61	4.42	5.06	6.54	6.21	--
Commercial	3.33	3.83	4.49	5.91	5.43	--
Industrial	2.81	3.64	4.39	5.78	5.29	--
Power Plant	2.70	3.49	4.48	5.82	4.92	--

Data Sources: 1. 1981 Annual Report to Congress, op. cit.
 2. A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit.
 3. "Consumer Impact of Indefinite Gas Price Escalator Clauses under Alternative Decontrol Plans," op. cit.
 *A dash signifies that the price is not available.

8 percent annually in real terms for the period of 1982 through 1987, and less than 2 percent annually for the period 1987 through 1992. In an updated projection, the AGA predicts that 1982 will be the last year of large wellhead gas price increases.⁸ After 1982, market forces begin to moderate these price increases. The ICF study also predicts that gas wellhead prices will decrease relative to crude oil after 1985.

Since wellhead prices constitute a large share of the gas bill for end users, retail prices follow the same pattern as wellhead prices. Despite the price jump in 1985, all three studies project a moderate increase in retail prices. For example, residential and commercial prices are projected to increase at an annual compound rate of 5 percent per year between 1982 and 1987, and 2 percent per year between 1987 and 1992 by the AGA study. An average 7 percent increase in real terms is predicted by the ICF study for the period of 1981-1984. A more moderate rate of increase for retail prices is projected after 1985. The retail price rise is larger and lasts longer in ARC81. This is probably because of an assumption of higher world oil prices.

Another difference is that both the ARC81 and ICF studies project that the national average natural gas price does not reach the Btu-equivalent price of competing petroleum products, although some industrial users may pay a Btu-equivalent price of high-sulfur residual fuel oil for gas in some parts of the country. The AGA study, however, projects that retail natural gas prices will catch up

⁸Reported in American Gas Association, Natural Gas Pricing Issues Fact Sheet (Washington, D.C.: Oct. 1982), and American Gas Association, Historical and Projected Natural Gas Prices (Washington, D.C.: Sept. 10, 1982).

or have now caught up with residual fuel oil prices in most industrial markets. As a result, the loss of market share by natural gas to fuel oil and liquefied petroleum gas is severe in the industrial and electric utilities market.

City-Gate Prices under Various Decontrol Proposals

Of the many proposals to decontrol the price of natural gas, four are most important. These were discussed in chapter 4 and could be summarized as (1) phased, partial decontrol or simply the NGPA plan, (2) phased, total decontrol, (3) immediate, partial decontrol or advancing the NGPA timetable, and (4) immediate, total decontrol. These policy options have been studied using the three forecasting models described in the first section of this chapter. The studies were conducted by three separate research groups and, not surprisingly, they do not necessarily agree about the consequences of any particular policy although they are frequently close. The city-gate price forecasts of these studies are used in chapter 6 of this report in an analysis of the end-user price equilibrium for regulated gas distributors.

There is no single price forecast that can be uniquely associated with any particular policy option. There is a great deal of uncertainty regarding these forecasts. The studies that have reported price forecasts under various decontrol proposals also have reported the consequences of changes in the economic environment such as lower oil prices or reduced natural gas demand due to an economic recession. The range of the forecasted prices due to changes in economic conditions is typically larger than the differences in prices due to policy actions. Consequently, there is a great deal of overlap in the range of forecasted prices of one policy option when compared to another. Before discussing the details of the price ranges for each decontrol proposal, the nature of the uncertainty about the price forecasting needs some elaboration.

The first source of uncertainty has to do with the overall economic conditions surrounding all energy markets, not just simply that of natural gas. For example, the 1981 Annual Report to Congress⁹ (ARC81), based upon MEFS, summarizes DOE's projections under a variety of plausible future oil prices. If the 1985 price of oil is \$26 per barrel (in 1980 dollars), the MEFS forecast for the 1985 average U.S. city-gate price of natural gas is \$4.22 per mcf. If, however, oil sells for \$33 per barrel, the price of natural gas at the city gate is forecasted to be \$5.32 per mcf, a 26 percent increase. Changes in the condition of supply and demand in the natural gas market itself have an even more dramatic effect on prices. The EIA study of accelerated deregulation¹⁰ includes an analysis of how sensitive natural gas prices are to (what in the opinion of the EIA study team constitute) plausible conditions about the strength or weakness of natural gas demand. Demand may be weak, for example, during an economic recession such as the one just experienced in the U.S. Assuming that the NGPA schedule of decontrol is followed, the EIA study found that city-gate prices are likely to increase by 56 percent between 1980 and 1985 if demand is somewhat slack.¹¹ If demand is relatively normal, however, city-gate prices might increase by 169 percent under the NGPA. Hence, there is approximately a 70 percent difference in the projected 1985 natural gas price due to normal versus slack demand circumstances.

⁹See 1981 Annual Report to Congress, op. cit.

¹⁰See Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices, op. cit.

¹¹The EIA study did not report city-gate prices directly. It did, however, report wellhead as well as final user prices. From this information, plus knowledge of the distributor's share of final user prices, the NRRI could infer city-gate prices. Any possible errors due to the inference are trivial in comparison to the inherent uncertainty of the forecasts.

A second source of uncertainty concerns the dynamic response of the natural gas market to changes in prices. In particular, all the forecasting models reviewed by the NRRRI have quite sophisticated representations of the time delays in both supply and demand. Such time lags are quite important, particularly so for supply. After natural gas prices rise, there may be a two-to-three-year period before any increased drilling activity actually results in new gas production. Such time delays are only imperfectly known, and consequently how rapidly the market adjusts is also subject to some uncertainty.

In addition, delayed supply responses can also affect the comparison of prices under various decontrol proposals in a particular year. The long-run price of natural gas, for example, will almost certainly be higher if all wellhead prices are totally decontrolled than if the price of old gas continues to be regulated. This may not be true in the short run, however. Suppose a policy of following the NGPA timetable is compared to that of having decontrolled wellhead prices totally in 1982. The 1985 average natural gas price forecasted by the EIA, under some circumstances, is higher under the NGPA than under total decontrol.

Even though the initial, intuitive answer would be to expect higher prices under total decontrol, the result is plausible if the dynamic response is considered. If natural gas prices had been totally freed from federal regulation in 1982, they would have greatly increased in the first year or two, according to the EIA study and the others. The rapid increase in prices would have induced drilling activity with noticeable production increases after a year or two. This supply increase actually serves to reduce prices, in real terms, after a few years. Thus, by 1985 most of the price shock would be absorbed in supply increases and some conservation. In contrast, the

policy of following the NGPA relaxes price controls on new gas in 1985. Even though old gas prices are kept low, 1985 is the initial year of decontrol, albeit partial. The initial price increase occurs in 1985, and no supply response occurs until a short time later. Consequently, the 1985 NGPA price can actually be higher than the 1985 price under a policy of complete decontrol that had been enacted in 1982. Thus, timing differences in the initiation of two decontrol policies can cause short-run anomalous price comparisons that disappear after a few years.

This brief discussion of the importance of economic circumstances and of the timing of any particular decontrol proposal provides a framework for presenting the range of city-gate price increases forecasted by the three studies of decontrol alternatives. These ranges are summarized in table 5-4. The table presents the ratios of 1985 to 1980 natural gas city-gate prices in the first column of numbers. The second column shows the ratios of 1990 to 1980 prices in order to provide a somewhat longer time perspective. These are real price ratios in that the prices entering the ratio calculation are expressed in constant dollars.

As indicated in the first line of table 5-4, the ICF study found that under the NGPA natural gas city-gate prices would be 2.09 times as high in 1985 as they were in 1980 (in real terms). If the NGPA timetable had been advanced to 1982, the ICF model predicted that prices would have been lower in 1985, and so the ratio of 1985 to 1980 city-gate prices is somewhat smaller, 1.96. Thus, a 1982 partial decontrol policy would result in a 96 percent price increase over the five years 1980 to 1985, while the NGPA would result in an 109 percent increase during this same period. Full decontrol in 1982 was forecasted to yield a 112 percent increase in the ICF report. Thus, the ICF Two-Market model forecasted a very modest difference in 1985 city-gate prices under all three decontrol proposals. There is less than an 8 percent difference in prices among all three proposals. In

TABLE 5-4

CITY-GATE PRICE RATIOS UNDER VARIOUS DECONTROL PROPOSALS:
1985 to 1980 and 1990 to 1980*

Decontrol Proposal	Study	Real Price Ratio	
		1985 to 1980	1990 to 1980
NGPA	ICF	2.09	2.39
	EIA	1.56 to 2.69	--
	AGA	3.57	4.19
1982 NGPA Timetable	ICF	1.96	2.39
	EIA	1.56 to 1.94	--
1982 Full Decontrol	ICF	2.12	2.47
	EIA	1.81 to 2.36	--

Data Sources: 1. A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit.
 2. Analysis of Economic Effects of Accelerated Deregulation of Natural Gas Prices, op. cit.
 3. "Consumer Impact of Indefinite Gas Price Escalator Clauses under Alternative Decontrol Plans," op. cit.
 *Dashes indicate that the 1990 forecasts were not published.

the longer run, by 1990 the ICF model forecasted an even smaller difference in prices between full and partial decontrol, only 3.3 percent.

The EIA study included forecasts under a variety of economic conditions as well as a variety of decontrol proposals. The range of price increases shown in table 5-4 for the EIA study is based upon the market conditions used in the 1980 Annual Report to Congress (which establish the upper end of the range) and upon somewhat more favorable supply conditions that tend to lower the 1985 price (which establish

the lower end).¹² As shown in the second line of table 5-4, the EIA study found that city-gate prices under the NGPA might increase by 56 to 169 percent from their 1980 levels, depending on the tightness of the market. If the NGPA schedule were advanced to 1982, the increase might be 56 to 94 percent. A policy of complete decontrol in 1982 could result in prices increasing from 81 to 136 percent. In all cases, the EIA price range includes the price forecasted by the ICF study.

By contrast, the AGA study, which reports forecasts only for the first of the three policies in the table, predicts a 3.57-fold increase in prices between 1980 and 1985 under the NGPA. Such an increase is far beyond those of the other two studies.

All three studies listed in table 5-4 were written in 1981. The recession of 1982 has subsequently reduced the demand for natural gas substantially. As a result, the price increases that were forecasted in 1981 are likely to be too high. For that reason, the NRRI study team decided to investigate a more limited range of city-gate price increases. The largest price rise from 1980 to 1985 that is considered in the following chapter is 125 percent, which corresponds to a price ratio of 2.25. This seems to be the largest foreseeable price increase that is consistent both with the studies in table 5-4 and with the current economic reality of slack demand in natural gas markets.

In addition, our equilibrium model of a gas distributor was applied to three other cases. The lowest real increase in the city-gate price that was considered is approximately 50 percent. The

¹²Somewhat more favorable supply can be interpreted to mean that the market has slightly more slack. In particular, the EIA constructed this case by assuming that supply is greater than that in the 1980 Annual Report to Congress by eight percent. See A Study of Alternatives to the Natural Gas Policy Act of 1978, op. cit., p. 9.

precise values were those in ARC81. In some regions the increase was larger than 50 percent, and in some it was less. With the overall range of real price increases to be studied being from 50 to 125 percent, the remaining issue is the number of intermediate points to be studied. From table 5-4 and the natural gas price uncertainty due to oil prices, it is clear that the limit of accuracy of these forecasting models is about 25 percentage points. That is, for any particular decontrol policy, the price forecast should be interpreted as an average or expected value with a range of uncertainty of plus or minus 12.5 percentage points or a total range of 25 points. Accordingly, chapter 6 reports results for a 75 and 100 percent real increase in city-gate price as well as the lower and upper ends of the range.

These price increases do not correspond well to particular decontrol policies. This is because the difference in prices between partial and total decontrol scenarios is only about 12 percent in the short run and even less in the long run. The range from 50 to 125 percent increase is considered because all factors taken together suggest that prices could vary to such an extent because of oil price changes or another economic recession. The difference between the 100 and 125 percent price increases represents approximately the difference between partial and total decontrol. Thus, the strategy in the following chapter is to study a sufficiently rich set of possible city-gate price increases that covers the entire range of forecasts reviewed here in light of the recent decline in the demand for natural gas.

As reported in chapter 6, this is accomplished by using ratios of 1985 to 1980 city-gate prices, that range from about 1.5 to 2.25 in increments of 0.25. The reader can interpret the difference between ratios of 2.0 and 2.25 as approximately equal to the difference between partial and total decontrol. The difference between 1.5 and 2.25 represents the difference between a slack and tight market for

natural gas. The difference between a policy of partial decontrol that is adopted immediately and one that is phased in over several years is very small, perhaps only half of the 25 percentage point increment or less. Such small price differences are not examined in the next chapter for two reasons: (1) they are smaller than the limits of accuracy of the forecasting models and (2) any such differences disappear after about five years since the long-run equilibrium is quite similar whether the decontrol occurs immediately or slowly over a few years. That is because the same set of gas categories is ultimately regulated in the two cases.

A particular value of the city-gate price ratio, such as a ratio of 2.00 meaning a doubling of the real city-gate price from 1980 to 1985, could occur as the result of a variety of circumstances. Prices might double because the wellhead gas market is totally decontrolled when there is some market slack or because it is only partially decontrolled when the market is somewhat tighter. Hence, particular values of the city-gate price ratio are less important than comparisons among them. The purpose of the following chapter is not so much to predict actual end-user prices, as it is to provide state regulators with information about the range of possible retail rates and to assess state regulatory policy options for affecting these rates.

CHAPTER 6

EFFECTS OF FEDERAL AND STATE PRICING POLICIES ON RETAIL GAS RATES

The effects of various federal and state commission pricing policies for natural gas are likely to vary from one region to another, depending upon (1) the region's reliance on natural gas versus alternate fuels, (2) the region's natural gas market mix (e.g., predominantly residential market or predominantly industrial market), and (3) the region's location with respect to gas production zones and the resulting pipeline transportation costs, which may amount to 10 cents per mcf close to a major field in Louisiana and \$1.50 per mcf in New England. A regionalized approach to the analysis of the effects of deregulation or other pricing policies on final gas customer rates is therefore necessary. In this study, the nation is divided into regions, and an actual utility is selected in each region. This utility is chosen on the basis of its representativeness of the natural gas market mix in the whole region. The cost, financial, and operating characteristics of this utility are then used as inputs to a model that combines price-related demand functions and traditional cost-of-service analysis and allocation procedures, and determines the equilibrium retail prices resulting from various levels of city-gate prices as well as from various cost allocation mechanisms.

An overview of this model is presented in the first section of this chapter. Its detailed structure and the data used to calibrate and apply it are then described. The reader who wants to skip over the technical specification of the model may go directly from the first section to the third section in which the results of applying the model under various city-gate prices and associated federal policies are analyzed. In the last section, the model is applied to an examination of the ability of state commissions to mitigate any

adverse effects of federal deregulation by altering distribution utility cost allocation policy.

Overview of the Model

The distribution utility cost model used to analyze the effects of pricing policies on customer retail rates is a static, partial equilibrium model that determines equilibrium retail prices for a future year under specific policy and other assumptions, and for a given actual utility. The equilibrium price represents, for each end-use sector, the intersection of that sector's demand and regulated supply curves, wherein the regulated prices are functions of the quantities demanded and the cost allocation procedures selected. A general flow diagram of the calculations in the model is presented in figure 6-1. It consists of three major, interlinked blocks: (1) exogenous data and assumptions (EDA), (2) sectoral gas demands calculations (SGD), and (3) cost-of-service analysis (COS).

The EDA block contains (1) future price forecasts for gas at the city gate and for alternate energy sources (electricity, residual and distillate oil, liquefied gas, coal); (2) the elasticities of the residential, commercial, and industrial gas demands with respect to the prices of gas, electricity, and the other alternate fuels; (3) utility-related parameters such as variable O&M unit costs, fixed costs, depreciation and tax rates, rate of return, and load factors; and (4) the selection of a method for allocating gas capacity costs (i.e., average-and-excess demand or peak responsibility).

Initial end-use prices are selected arbitrarily, although naturally higher than the assumed city-gate price, and are used to calculate the initial sectoral gas demands in the SGD block. The demand functions selected are of the constant elasticity type and are calibrated to reflect the actual market demands of the selected utility.

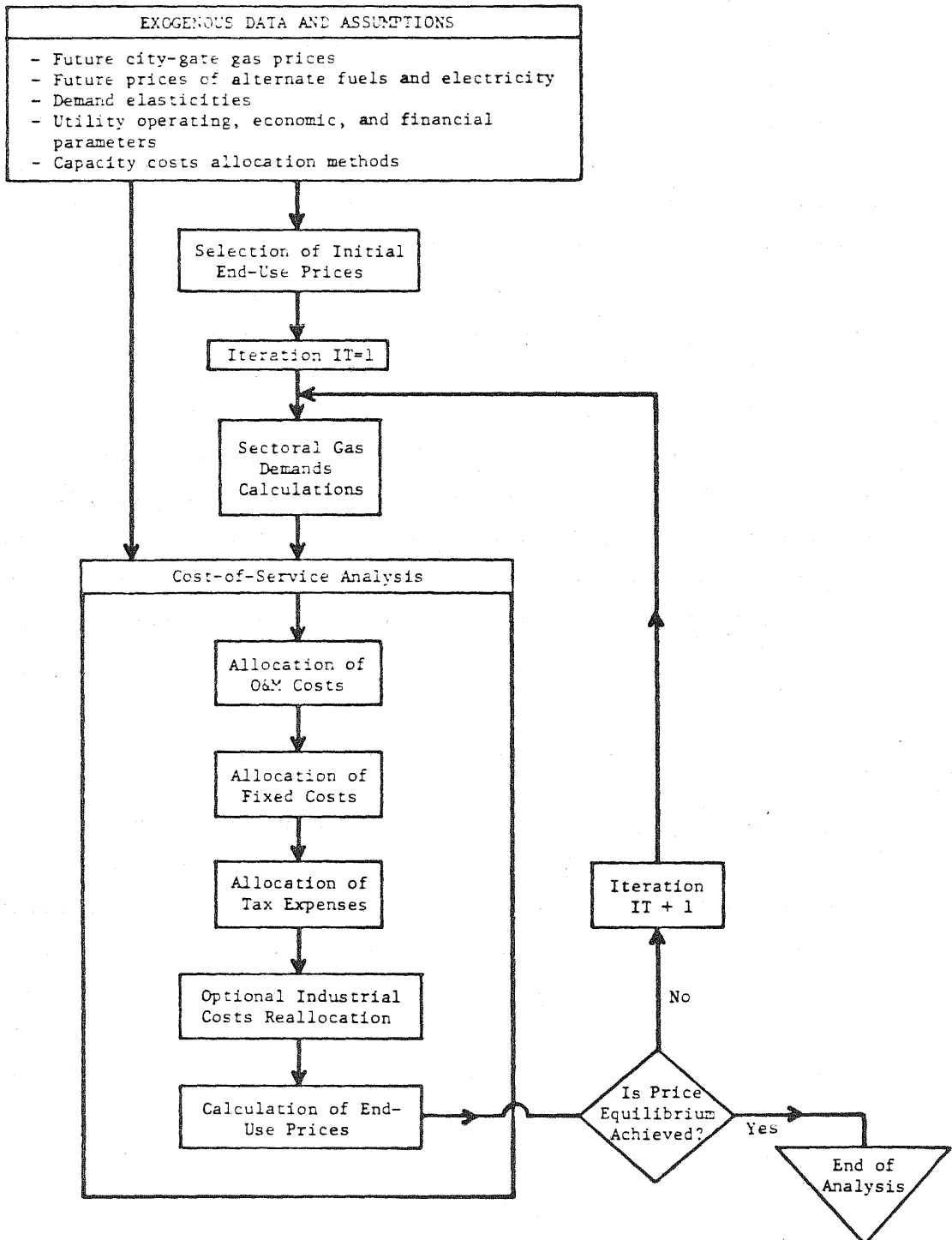


Figure 6-1 Structure of the distribution utility cost model

The calculated sectoral gas demands and other EDA parameters are then inputs to the COS block, wherein variable O&M and fixed plant costs, as well as tax expenses, are allocated to the residential, commercial, and industrial customer classes on the basis of traditional cost allocation principles. The COS block includes the option of reallocating any component of the industrial costs to the other two sectors. Once all costs are allocated, unit end-use prices are computed, which should provide coverage of all costs, including the allowed regulated return on investment, provided that these prices lead to sectoral demands equal to those used as inputs to the COS block. If this is the case, then price equilibrium has been achieved, and the model calculations are completed. Otherwise, the calculated end-use prices are inputs to the SGD block, and the same cycle of calculations takes place again and is iterated until equilibrium is achieved, i.e., when the differences between the sectoral prices of two consecutive iterations are less than an exogenously selected small value.

The Distribution Utility Cost Model

A detailed description of the model and associated data is presented in this section. The organization and listing of the computer program implementing the model are presented in appendix E. This section, which describes the structure and data of the Distribution Utility Cost Model, contains four major subsections: (1) a description of the market, economic, and financial parameters characterizing each regional utility, as well as the methods for projecting these parameters for any horizon year; (2) a detailed description of the equilibrium model of a regulated distributor, including a cost-of-service analysis, a gas demand analysis, and an equilibrating mechanism; (3) a detailed presentation of the data used; and (4) an assessment of the validity of the model based on calibration and testing. To assist those who may want to cross-reference this

discussion with the program listing in appendix E, a modified form of FORTRAN notation is used here. A "0" in the last character of a variable name indicates that it is a base year parameter.

Utility Parameters

a. Base-Year Parameters

The base year is the latest year for which actual market, price, cost, and financial data pertaining to the utility under study could be gathered. As discussed in more detail later on, the base year in this study is 1980. The base-year parameters, which are necessary to compute projection-year parameters, can be grouped into three categories.

(1) Market parameters

Each utility market is disaggregated into three customer classes--residential, commercial, and industrial--which are indexed by $i=1, 2, \text{ and } 3$, respectively. Each class is characterized by four parameters:

NO_i = number of customers,

QO_i = annual gas sales (mcf),

PO_i = average gas retail price (\$/mcf),

K_i = ratio of peak month sales to annual sales.

The parameters K_i are determined by estimating monthly load equations for each class, specifically by regressing observed monthly loads on the corresponding monthly heating degree-days, with

$$QM_{im} = QM_i (DD_m), \quad (1)$$

where QM_{im} is the 1979 load of class i during month m , DD_m is the number of degree-days for each month of 1979, and QM_i is a function

which is either linear or log-linear, chosen on the basis of the smallest residuals sum of squares.¹ \overline{DD}_m is the 30-year average number of degree-days for each of the twelve months of the year, obtained from the National Oceanic and Atmospheric Administration.² The maximum of these twelve monthly degree-day averages is denoted \overline{DD}_{max} . It is used to predict peak sales for an average year and to compute K_i as

$$K_i = \frac{QM_i (\overline{DD}_{max})^2}{12 \sum_{m=1}^{12} QM_i (\overline{DD}_m)^2} \quad (2)$$

The parameters K_i are used to predict peak sectoral demands, the aggregation of which for the base year is

$$TPQO = \sum_{i=1}^3 K_i * QO_i \quad (3)$$

This is used to allocate peak-demand-related costs. This procedure, in effect, eliminates any unusual weather patterns from the calculation of peak-responsibility cost allocation factors.

Since the actual system peak, QDO, is available for the base year, the daily load factor can be calculated and is

$$LF = \frac{\sum_{i=1}^3 QO_i}{(QDO * 365)} \quad (4)$$

¹See P. Rao and R.L. Miller, Applied Econometrics (Belmont, California: Wadsworth Publishing Company, 1971), pp. 107-111.

²U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service, Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree-Days 1941-1970 (Asheville, N.C.).

(ii) Operating cost and plant parameters

The operation and maintenance costs parameters include:

PGASO = average city-gate price of gas (\$/mcf),

CSOMO = O&M cost of storage (\$),

CTOMO = O&M cost of transmission (\$),

CDOMO = O&M cost of distribution (\$),

CAOO = customer accounts expenses (\$),

CSOO = customer services expenses (\$),

SAOO = sales and advertising expenses (\$),

AGO = administrative and general expenses (\$).

Note that the average city-gate price PGASO is computed by dividing all base-year gas supply expenses, including possibly the O&M cost of utility-produced natural and/or synthetic gas, by the total amount of gas purchased and produced.

The end-of-base-year plant parameters include:

MGPO = manufactured gas production plant in service (\$),

NGPO = natural gas production plant in service (\$),

STPO = storage plant in service (\$),

TRPO = transmission plant in service (\$),

DPO = distribution plant in service (\$),

GPO = general plant in service (\$).

(iii) Financial parameters

Financial parameters include depreciation, rate of return, and tax-related parameters, with:

DEPO = total plant depreciation during the base year (\$),

ADJ = ratio of the net to gross plant in service,

R = actual rate of return,

INCTXO = income taxes, including both Federal and State taxes (\$),

RVTO = revenue-related taxes (\$),

PRTO = property-related taxes (\$),

RVO = total gas sales revenues (\$).

If ACDEPO is the accumulated depreciation, the net plant in service, NPISO, is defined by

$$\text{NPISO} = \text{GPISO} - \text{ACDEPO}, \quad (5)$$

with GPISO, gross plant in service, given by

$$\text{GPISO} = \text{MGPO} + \text{NGPO} + \text{STPO} + \text{TRPO} + \text{DPO} + \text{GPO}. \quad (6)$$

It then follows that

$$\text{ADJ} = \text{NPISO}/\text{GPISO}. \quad (7)$$

The net plant in service is the rate base, to which the allowed rate of return is applied to determine the allowed operating income. In this study, the actually achieved rate of return in the base year is used as the allowed rate of return in the projections/impacts analyses. If OPINCO is the base-year operating income, it follows that

$$\text{R} = \text{OPINCO}/\text{NPISO}. \quad (8)$$

Finally, taxes other than income taxes were apportioned among revenue-related and property-related taxes in the ratio 73:27, based upon more detailed analyses.³

b. Projection Year Parameters

Because the model is to be used to analyze the impacts of price increases on the sectoral demands for gas, Q_i 's, these demands must be functions of the future retail prices of gas, P_i 's, and of the future retail prices of the alternate fuels that may be substituted for gas. Let \bar{P}_{iA} be the vector of the prices of these alternate fuels. Hence,

³The National Association of Regulatory Utility Commissioners (NARUC), Gas Utility Cost Allocation Methods, unpublished report of the NARUC Staff Subcommittee on Gas.

$$Q_i = Q_i (P_i, \bar{P}_{iA}). \quad (9)$$

The calibration procedure for the above demand functions is fully explained in a later section. The determination of the future prices is also discussed in later sections. While, in the long term, changes in quantity demanded are likely to be accompanied by changes in the numbers of customers attached to the system, no data or prior research were available to calibrate functions predicting the number of customers. It was assumed that the sectoral numbers of customers, N_i , would remain constant and equal to their base-year values. Also, the load patterns of each sector separately and of the market as a whole are assumed invariant, hence the use of the parameters K_i and LF in projection-year calculations.

As the study focuses on the impact of future price increases, demands will decrease; hence, the utility will not experience any expansion in its plant, i.e., any increase in its fixed costs. As an approximation, the projection-year gross and net plants in service are taken equal to the corresponding base-year values. Assuming a constant depreciation rate, the future annual depreciation is then also equal to the base-year depreciation. As the rate base and the allowed rate of return are the same as in the base year, the allowed operating income, of course, does not change, and, as a consequence, income taxes taken as proportional to this income do not change either. Finally, the property-related taxes also do not vary, as they are taken proportional to the total gross plant in service.

The projection-year O&M costs are computed in a way consistent with the usual customer class allocation procedures. Let TQ and TPQ be the future total annual demand and peak month demand, with

$$TQ = \sum_{i=1}^3 Q_i, \quad (10)$$

and

$$TPQ = \sum_{i=1}^3 K_i * Q_i. \quad (11)$$

If IP_g is the index of growth of the average city-gate price between the base and projection years, the future city-gate price is

$$PGAS = IP_g * PGASO, \quad (12)$$

and the total cost of gas supply is

$$CSUP = PGAS * TQ. \quad (13)$$

Storage costs are the sum of two components: (a) CSOM1, proportional to total annual sales, and (b) CSOM2, proportional to the difference between peak and average monthly loads. The share of CSOM1 in the total cost CSOM is taken equal to the daily load factor LF. Hence,

$$CSOM1 = CSOMO * LF * (TQ/TQO), \quad (14)$$

and

$$CSOM2 = CSOMO * (1-LF) * \left[\frac{TPQ - TQ/12}{TPQO - TQO/12} \right] \quad (15)$$

where $TQO = \sum QO_i$ is the base-year total annual gas demand.

Transmission O&M costs projections are computed in exactly the same way as storage O&M costs. A fraction, SCD, of distribution O&M costs is taken as proportional to the number of customers, and hence does not change under our customer-related assumption, while the remainder (1-SCD) is projected in the same way as storage and transmission O&M costs. Customer accounts, customer services, and sales expenses are taken as proportional to the number of customers, and therefore do

not vary from the base to the projection years. Finally, administrative and general costs, assumed proportional to total annual sales, are projected equal to

$$AG = AGO * (TQ/TQO). \quad (16)$$

Revenue-related taxes, RVT, are proportional to the total gas sales revenues, RV:

$$RV = \sum_{i=1}^3 P_i * Q_i. \quad (17)$$

It follows that

$$RVT = RVTO * (RV/RVO). \quad (18)$$

The Equilibrium Model of a Regulated Distributor

The model is described here in three subsections: (a) the cost of service, (b) the demand by final users, and (c) the solution procedure.

a. The Cost of Service

(i) A Summary of typical cost allocation procedures

The process of rate design starts with the allocation of the operating expenses, fixed costs, and taxes to the different customer classes, and the functionalization of these costs as customer costs, energy or commodity costs, and demand or capacity costs. There are no absolute rules for functional allocation. However, the following represents the most typical functional grouping, with C indicating a customer cost, D a demand cost, and E an energy cost:

- production plant and purchased gas costs: D,E
- storage and transmission plants and expenses: D
- distribution and general plants and expenses: D,C
- customer accounts and services expenses: C
- sales promotion expenses: D,C.

Customer costs are the costs that vary directly with the numbers of customers served rather than with the amounts of gas supplied, either on an annual or a peak-day basis. Energy or commodity costs vary with the quantity of gas produced or purchased annually. Demand or capacity costs vary with the quantity or size of plant and equipment and are essentially related to the peak daily (or hourly) demand. For a given cost category (e.g., storage O&M), the first step is to apportion the total cost among the customer, energy, and demand categories. This apportionment is generally based on a breakdown of the total cost into subaccounts. For instance, in the case of the distribution plant, the investment in meters and services is related exclusively to the number of customers. However, distribution mains involve both demand and customer components, and customer-related costs are estimated as those that would be necessary to install the same main network, but with minimum-size pipes. The remaining costs then represent the demand-related costs. In the case of the production plant and expenses, when this plant is related to natural gas production, then costs are classified as energy-related, because this production is necessarily steady throughout the year. However, expenses related to gas manufactured to meet the peak are characterized as demand costs.

Total energy costs are allocated to the various customer classes in proportion to their annual gas consumptions. Total customer costs are allocated in proportion to the number of customers in each class, with appropriate weighting to account for differential size effects (e.g., a large industrial customer meter will cost more than a standard residential one). Most of the controversy about cost allocation centers on the allocation of demand or capacity costs. There are several methods for allocating these costs, and no method is universally accepted.

The peak responsibility method, also called the coincident demand method, allocates demand costs in proportion to the various classes' demands at the time of the system peak.

The noncoincident demand method allocates demand costs in proportion to the various classes' actual peaks, regardless of the times of occurrence.

The average-and-excess demand method is a compromise between the above two. Total demand costs are multiplied by the system's load factor to arrive at the costs attributable to average use and allocable on an annual volumetric basis. The remaining costs are allocated to customer classes in proportion to the difference between peak and average demands.

(ii) A simplified model of the cost of service

We showed above how projection-year costs are estimated, given a forecast of the sectoral annual gas demands Q_i 's. Here, we show how each cost component is allocated to the three customer classes. Each allocated amount is then divided by the sectoral annual demand, leading to component unit costs ($\$/\text{mcf}$). When summed up, these unit costs are equal to the average sectoral retail prices of gas that should enable the utility to recover all its costs. Naturally, the computed retail prices may lead to values for the annual demands Q_i 's different from the initially postulated values. The determination of the equilibrium price-quantity values is discussed later on. In this section, we start with exogenously fixed values for the Q_i 's and show how the resulting prices P_i 's are determined.

The Allocation of the Operating Costs

The O&M components' unit costs are denoted X_{ji} for component j and customer class i . Storage costs are allocated according to the average-and-excess demand method, with X_{1i} and X_{2i} corresponding to the "excess" and "average" components:

$$X_{1i} = CSOMO*(1-LF)* \left[\frac{K_i - 1/12}{TPQO - TQO/12} \right] \text{ (excess)} \quad (19)$$

and

$$X_{2i} = CSOMO * LF/TQO \text{ (average)}. \quad (20)$$

Transmission costs are allocated in the same way as storage costs, with X_{3i} and X_{4i} corresponding to the "excess" and "average" components:

$$X_{3i} = CTOMO*(1-LF)* \left[\frac{K_i - 1/12}{TPQO - TQO/12} \right] \text{ (excess)} \quad (21)$$

and

$$X_{4i} = CTOMO * LF/TQO \text{ (average)}. \quad (22)$$

In the case of distribution costs, a fraction SCD is treated as customer costs. If W_i is the weight assigned to a customer in class i , the customer allocation factor is defined by

$$FN_i = \frac{W_i * NO_i}{\sum_{i=1} W_i * NO_i}, \quad (23)$$

and the customer-related unit distribution cost X_{5i} is then

$$X_{5i} = CDOMO * SCD * FN_i/Q_i. \quad (24)$$

The remaining distribution costs are allocated according to the average-and-excess demand method, with

$$X_{6i} = CDOMO*(1-SCD)*(1-LF)* \left[\frac{K_i - 1/12}{TPQO - TQO/12} \right] \text{ (excess)}, \quad (25)$$

and

$$X_{7i} = \text{CDOMO} * (1 - \text{SCD}) * \text{LF/TQO (average)}. \quad (26)$$

The value selected for SCD is 0.44, as reported in the Natural Gas Rate Design Study.⁴ Customer accounts, customer services, and sales promotion expenses are allocated on the basis of the numbers of customers, with the following unit costs:

$$X_{8i} = \text{CA00} * \text{FN}_i / \text{Q}_i, \quad (27)$$

$$X_{9i} = \text{CS00} * \text{FN}_i / \text{Q}_i, \quad (28)$$

$$X_{10i} = \text{SA00} * \text{FN}_i / \text{Q}_i. \quad (29)$$

The allocation factors used for the administrative and general costs AG are a composite of the other O&M costs allocation factors, with

$$\text{AFAG}_i = \frac{\sum_{j=1}^{10} X_{ji} * \text{Q}_i}{\sum_{i=1}^3 \sum_{j=1}^{10} X_{ji} * \text{Q}_i} \quad (30)$$

as the allocation factor for sector i. The corresponding unit costs are then

$$X_{11i} = \text{AGO} * \left(\frac{\text{TQ}}{\text{TQO}} \right) * \frac{\text{AFAG}_i}{\text{Q}_i} \quad (31)$$

⁴U.S. Department of Energy, Natural Gas Rate Design Study (Washington, D.C.: 1980).

The Allocation of the Rate Base

The net to gross plant in service ratio ADJ is uniformly applied to all the plant components, and the net plant components are allocated to the customer classes. Let Y_{ji} be the unit price for component j and class i . The manufactured gas production plant is allocated on the basis of the average-and-excess demand method, with:

$$Y_{1i} = \text{MGPO} * \text{ADJ} * (1 - \text{LF}) * \left[\frac{K_i - 1/12}{\text{TPQ} - \text{TQ}/12} \right] \quad (\text{excess}), \quad (32)$$

$$Y_{2i} = \text{MGPO} * \text{ADJ} * \text{LF} / \text{TQ} \quad (\text{average}). \quad (33)$$

The natural gas production plant is allocated on an annual volumetric basis, with

$$Y_{3i} = \text{NGPO} * \text{ADJ} / \text{TQ}. \quad (34)$$

The storage, transmission, and distribution plants are allocated in exactly the same way as the corresponding O&M costs, with storage plant allocated by

$$Y_{4i} = \text{STPO} * \text{ADJ} * (1 - \text{LF}) * \left[\frac{K_i - 1/12}{\text{TPQ} - \text{TQ}/12} \right] \quad (\text{excess}), \quad (35)$$

and

$$Y_{5i} = \text{STPO} * \text{ADJ} * \text{LF} / \text{TQ} \quad (\text{average}); \quad (36)$$

with transmission plant allocation by

$$Y_{6i} = \text{TRPO} * \text{ADJ} * (1 - \text{LF}) * \left[\frac{K_i - 1/12}{\text{TPQ} - \text{TQ}/12} \right] \quad (\text{excess}), \quad (37)$$

$$Y_{7i} = \text{TRPO} * \text{ADJ} * \text{LF} / \text{TQ} \quad (\text{average}); \quad (38)$$

and with distribution plant allocated by

$$Y_{8i} = \text{DPO} * \text{ADJ} * \text{SCD} * \text{FN}_i / Q_i \quad (\text{customer}), \quad (39)$$

$$Y_{9i} = \text{DPO} * \text{ADJ} * (1 - \text{SCD}) * (1 - \text{LF}) * \left[\frac{K_i - 1/12}{\text{TPQ} - \text{TQ}/12} \right] \quad (\text{excess}), \quad (40)$$

and

$$Y_{10i} = \text{DPO} * \text{ADJ} * (1 - \text{SCD}) * \text{LF} / \text{TQ} \quad (\text{average}). \quad (41)$$

The allocation factors used for the general plant GPO are a composite of the other plant component allocation factors, with

$$\text{AFGPO}_i = \frac{\sum_{j=1}^{10} Y_{ji} * Q_i}{\sum_{i=1} \sum_{j=1}^{10} Y_{ji} * Q_i} \quad (42)$$

as the allocation factor for sector i. The general plant unit costs are then

$$Y_{11i} = \text{GPO} * \text{ADJ} * \text{AFGPO}_i / Q_i. \quad (43)$$

The Allocation of Depreciation and Tax Expenses

Annual depreciation and some tax expenses are allocated with an allocation factor AFRB_i that reflects the allocation of the whole rate base:

$$\text{AFRB}_i = \frac{\sum_{j=1}^{11} Y_{ji} * Q_i}{\sum_{i=1} \sum_{j=1}^{11} Y_{ji} * Q_i} \quad (44)$$

The depreciation expenses unit costs are then

$$D_i = \text{DEPO} * \text{AFRB}_i / Q_i . \quad (45)$$

Property and income taxes are allocated with the factors AFRB_i . The corresponding sectoral unit costs are

$$\text{TP}_i = \text{PRTO} * \text{AFRB}_i / Q_i , \quad (46)$$

and

$$\text{TI}_i = \text{INCTXO} * \text{AFRB}_i / Q_i . \quad (47)$$

Revenue taxes are simply allocated on the basis of sectoral revenues, with the following unit costs:

$$\text{TR}_i = (\text{RVTO}/\text{RVO}) * P_{i0} . \quad (48)$$

P_{i0} is the initially postulated retail price on the basis of which the quantity Q_i is calculated.

The Calculation of the Final Retail Sectoral Prices

The sectoral contributions to the final prices due to the return on the rate base are denoted B_i , with

$$B_i = R * \sum_{j=1}^{11} Y_{ji} . \quad (49)$$

Assuming that gas supply expenses are allocated exclusively on an annual volumetric basis (i.e., demand charges, based on peak day supplies, are non-existent or negligible), the final sectoral prices P_i are then

$$P_i = PGAS + \sum_{j=1}^{11} X_{ji} + B_i + D_i + TP_i + TI_i + TR_i. \quad (50)$$

If gas demands resulting from this pricing structure are equal to those initially postulated (P_{i0}, Q_i) , then $P_i = P_{i0}$, and an equilibrium price structure has been obtained. How to achieve such an equilibrium is fully explained in a later section.

Industrial Costs Reallocation

A policy option considered in the model is the reallocation of some (or all) of the industrial variable and fixed costs to the residential and commercial customers. Such a policy would lead to lower industrial gas prices, and hence to a smaller shrinkage of the industrial market, which has a high price elasticity. On the other side, the resulting higher residential and commercial prices would lead to smaller market changes because these sectors have a relatively low price-elasticity of demand. In order to account for such a reallocation, new unit prices X'_{ji} and Y'_{ji} must be calculated after the quantities X_{ji} and Y_{ji} have been estimated, based on the formulas presented in the previous sections.

Let Z_3 be the fraction of industrial costs reallocated. The new industrial unit prices are then simply

$$X'_{j3} = X_{j3} * (1 - Z_3) , \quad (51)$$

and

$$Y'_{j3} = Y_{j3} * (1 - Z_3) . \quad (52)$$

The costs reallocated amount to $Z_3*Q_3*X_{j3}$ and $Z_3*Q_3*Y_{j3}$, and are apportioned among residential and commercial customers on the basis of their annual demands Q_1 and Q_2 . The new unit prices are then

$$X'_{j1} = X_{j1} + [Z_3*X_{j3}*Q_3/(Q_1+Q_2)] \quad , \quad (53)$$

$$X'_{j2} = X_{j2} + [Z_3*X_{j3}*Q_3/(Q_1+Q_2)] \quad , \quad (54)$$

$$Y'_{j1} = Y_{j1} + [Z_3*Y_{j3}*Q_3/(Q_1+Q_2)] \quad , \quad (55)$$

$$Y'_{j2} = Y_{j2} + [Z_3*Y_{j3}*Q_3/(Q_1+Q_2)] \quad . \quad (56)$$

The above reallocations may apply to either O&M costs or fixed costs or both. In the model applications discussed later on, both O&M costs (excluding, of course, supply expenses) and fixed costs are reallocated. The calculation of the allocation factors $AFRB_i$ (in equation 44) used to allocate tax and depreciation expenses is then based on the unit costs Y'_{ji} instead of the costs Y_{ji} .

b. Demand by Final Users

As indicated in the preceding subsection, sectoral gas demands are functions of the sectoral prices of gas and other competing fuels at the retail level. There is an important econometric literature on gas demand functions estimation.⁵ These studies propose constant price-elasticity functions. However, their elasticity estimates vary over significantly wide ranges. Instead of attempting our own estimation, which was not possible because of lack of appropriate data and research time, we have assumed that the residential, commercial, and industrial annual gas demands are of the constant price-elasticity

⁵See, for instance, the summary in appendix C of the Natural Gas Rate Design Study, op. cit.

type with respect to all prices, and that the corresponding elasticities are those used or estimated by the demand models of the Midterm Energy Forecasting System (MEFS).⁶ The elasticities used are, of course, the long-term ones, and the general forms of the demand functions are described below.

Residential gas demand is proportional to a product of prices, each raised to a power equal to the corresponding elasticity.

$$Q_1 = D_1 * P_{g,1}^{E_{g,1}} * P_{el,1}^{E_{el,1}}, \quad (57)$$

where

- $P_{g,1}$ = residential retail price of gas,
- $E_{g,1}$ = gas price elasticity of residential gas demand,
- $P_{el,1}$ = residential retail price of electricity,
- $E_{el,1}$ = cross price elasticity of residential gas demand with respect to electricity,
- D_1 = constant.

Commercial gas demand is given by

$$Q_2 = D_2 * P_{g,2}^{E_{g,2}} * P_{el,2}^{E_{el,2}}, \quad (58)$$

where

- $P_{g,2}$ = commercial retail price of gas,
- $E_{g,2}$ = gas price elasticity of commercial gas demand,
- $P_{el,2}$ = commercial retail price of electricity,

⁶For more details about MEFS, see the description in chapter 5 of this report.

$E_{el,2}$ = cross price elasticity of commercial gas demand
with respect to electricity,

D_2 = constant.

Industrial gas demand is given by

$$Q_3 = D_3 * P_{g,3}^{E_{g,3}} * P_{el,3}^{E_{el,3}} * P_{df,3}^{E_{df,3}} * P_{rf,3}^{E_{rf,3}} * P_{lg,3}^{E_{lg,3}} * P_{c,3}^{E_{c,3}}, \quad (59)$$

where

$P_{g,3}$ = industrial retail price of gas,

$E_{g,3}$ = gas price elasticity of industrial gas demand,

$P_{el,3}$ = industrial retail price of electricity,

$E_{el,3}$ = cross price elasticity of industrial gas demand
with respect to electricity,

$P_{df,3}$ = industrial retail price of distillate oil,

$E_{df,3}$ = cross price elasticity of industrial gas demand
with respect to distillate oil,

$P_{rf,3}$ = industrial retail price of residual oil,

$E_{rf,3}$ = cross price elasticity of industrial gas demand
with respect to residual oil,

$P_{lg,3}$ = industrial retail price of liquefied gas,

$E_{lg,3}$ = cross price elasticity of industrial gas demand
with respect to liquefied gas,

$P_{c,3}$ = industrial retail price of coal,

$E_{c,3}$ = cross price elasticity of industrial gas demand
with respect to coal,

D_3 = constant.

For equations 57-59 to be fully specified (or calibrated), it is necessary to determine the values of the multiplicative constants D_1 , D_2 , and D_3 . These values are calculated in such a way that the base-year quantities yielded by these equations are exactly equal to the observed base-year annual gas sales QO_i , with the retail prices of gas being the base-year average gas retail prices PO_i charged by the utility under study, and the retail prices of the alternate fuels being estimated as interpolations between the 1979 observed and the 1985 projected prices, as used in and produced by the MEFS model.

c. The Solution Procedure

The sectoral prices computed in the cost-of-service model (given in equation 50) are inputs to the sectoral gas demand functions presented in the previous section, and the resulting quantities are, of course, basic inputs to the cost-of-service model. The demand and cost-of-service models are therefore closely interrelated, and the problem is to find the retail gas price vector $P = (P_1, P_2, P_3)$ that leads to an equilibrium. The nature of the problem may be formally illustrated as follows. Let $Q = (Q_1, Q_2, Q_3)$ be the vector of gas demands, with Q as some general function, G , of P :

$$Q = G(P). \quad (60)$$

It is assumed that the prices of the alternate fuels are constant parameters. The retail prices, as finally computed in equation 50, depend upon the quantities of gas sold, hence:

$$P = F(Q), \quad (61)$$

where F is the vector function summarizing all the calculations of the cost-of-service model. The function (61) can be written in inverse form

$$Q = F^{-1}(P), \quad (62)$$

and the equilibrium solution is obtained by solving the system of equations

$$G(P) = F^{-1}(P). \quad (63)$$

There are several computerized numerical methods to solve such systems of equations. The approach selected here is called the fixed point method. It involves an iterative procedure that can be summarized as follows:

Iteration 1: Select an arbitrary price vector $P_0 = (P_{10}, P_{20}, P_{30})$

Iteration t: Using the price vector P_{t-1} determined in the previous iteration, compute the demand vector $Q_t = G(P_{t-1})$ and the new price vector $P_t = F(Q_t) = F(G(P_{t-1}))$.

If the differences between consecutive prices $|P_{it} - P_{it-1}|$ are below a selected threshold, stop the fixed point search, as the procedure has converged and the equilibrium prices have been obtained. Otherwise, start iteration $(t+1)$.

It is necessary to outline how the model was initially calibrated. Indeed, the equilibrium prices yielded by the model under base-year conditions must be very close, if not equal, to the observed retail prices. However, such a result will be achieved only if, at the equilibrium, the costs allocated to the three sectors reflect

exactly the cost allocations actually implemented by the utility. While the allocation procedures selected in the cost-of-service model are fairly common practice in the gas distribution industry, there may be differences from one utility to another. To account for these (unknown) factors, sensitivity analyses over the weights W_i used in determining customer allocation factors (in equation 23) were performed, and the set of weights leading to equilibrium prices closest to the observed prices were selected.

However, in order to discuss the calibration of the model it is useful to present first the data set upon which both the calibration and the actual runs were based. The data are described in the next subsection and the calibration is discussed in the last subsection of this presentation of the model.

The Data

The major data used in the model presented in the previous section and the procedures used to prepare these data are described in this section. We first present the regional disaggregation, then the characteristics of the regional utilities, and finally the characteristics of the demand functions.

a. Regional Disaggregation

The 10 federal regions used in the MEFS model have been selected for this study. These regions are delineated on figure 6-2 and are

- (1) New England: Maine, Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island;
- (2) East North Central: New York, New Jersey;
- (3) Middle Atlantic: Pennsylvania, West Virginia, Virginia, Maryland, Delaware, District of Columbia;

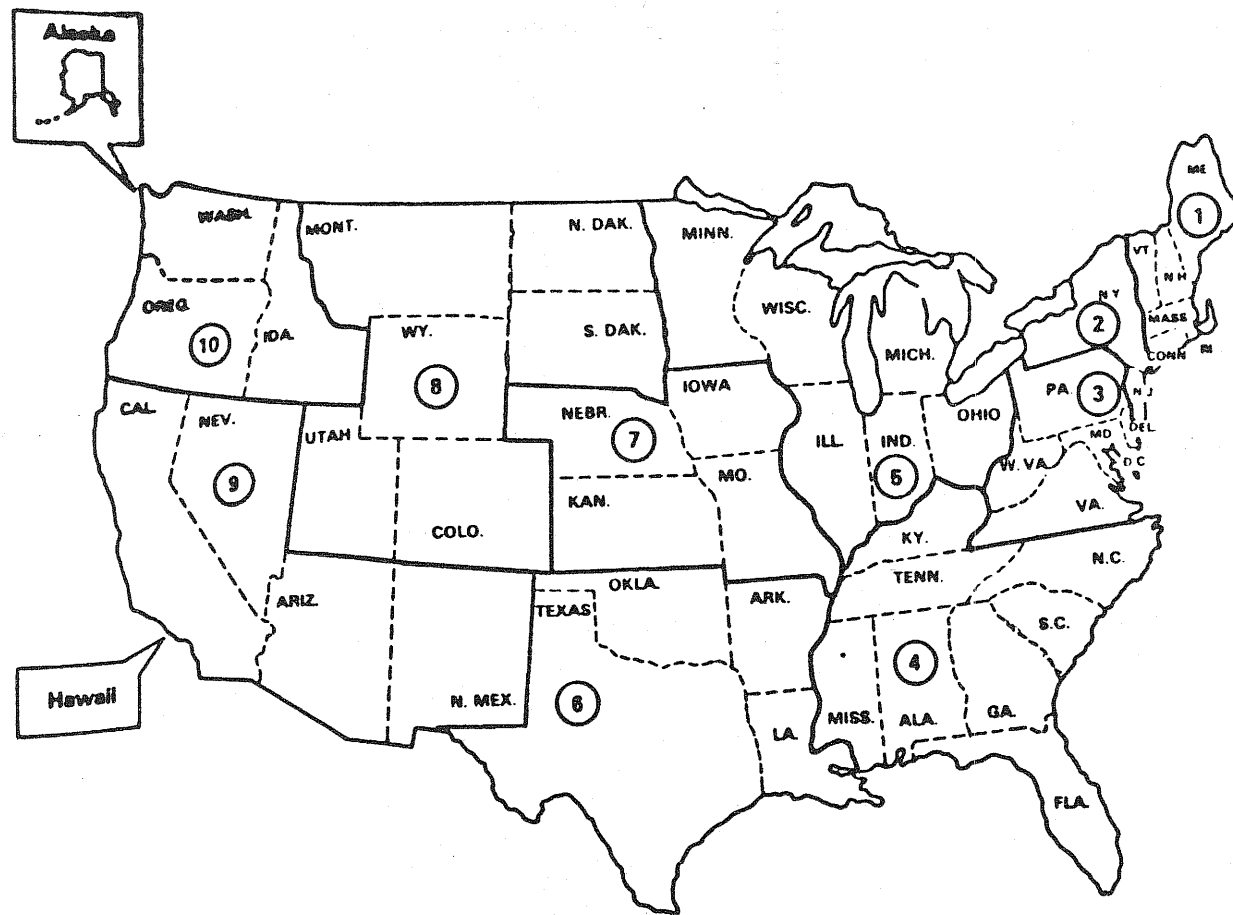


Figure 6-2 Ten Federal Regions (MEFS Demand Regions)

Source: Energy Information Administration, U.S. Department of Energy, 1981 Annual Report to Congress

- (4) South Atlantic: Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida;
- (5) Midwest: Ohio, Michigan, Indiana, Illinois, Wisconsin, Minnesota;
- (6) Southwest: Texas, Oklahoma, Arkansas, Louisiana;
- (7) Central: Iowa, Missouri, Kansas, Nebraska;
- (8) North Central: Montana, Wyoming, Utah, Colorado, North Dakota, South Dakota;
- (9) West: California, Nevada, Arizona, New Mexico, Hawaii;
- (10) North West: Washington, Oregon, Idaho, Alaska

The 1980 market mixes of these regions in terms of gas sales have been determined by aggregating state-level 1980 gas sales, as reported in the 1980 issue of Gas Facts,⁷ and are presented in table 6-1.

TABLE 6-1
1980 GAS SALES MIX IN TEN REGIONS

Region	Market Share (%)		
	Residential	Commercial	Industrial
N. Eng.	48.3	27.2	24.5
E.N. Centr.	52.6	19.4	28.0
Mid. Atl.	40.0	17.9	42.1
Sou. Atl.	22.6	14.6	62.8
Midwest	42.8	19.6	37.6
Southwest	12.0	6.8	81.2
Central	33.3	20.7	46.0
N. Centr.	36.9	23.2	39.9
West	31.0	15.6	53.4
<u>N. West</u>	<u>22.9</u>	<u>20.7</u>	<u>56.4</u>
U.S.	32.9	16.1	51.0

Source: Gas Facts-1980 Data, AGA, 1981.

⁷American Gas Association, Policy Evaluation and Analysis Group, Gas Facts-1980 Data (Arlington, Virginia: 1981).

There is a significant variability in market mix among the 10 regions, ranging from predominantly residential markets in New England and the East North Central region to predominantly industrial markets in the Southwest, South Atlantic, West, and North West regions. This variability alone therefore warrants a regional approach to the analysis of the impacts of alternative pricing policies on customer rates. As will be seen in the next section, average city-gate prices also display considerable variability from one region to another. The next step was to select, in each region, a gas distribution utility having a gas sales market mix as close as possible to the regional mix presented in table 6-1.

b. Utility Characteristics

Two distinct data sources were used in determining the values of the utility parameters: (1) the computerized utility data file COMPUSTAT for 1980, and (2) data gathered on 120 gas utilities during past NRRI research. The "NRRI file" includes data extracted from the 1979 annual report of each utility to its state regulatory commission and from the 1979 Uniform Statistical Report (USR) prepared (optionally) by the utility for the American Gas Association. The USR includes monthly loads and degree-days data, which were used to compute the load parameters K_1 . The other data were extracted from the 1980 COMPUSTAT records and from the 1979 annual reports when the data were unavailable in COMPUSTAT. In this case, the 1979 values were inflated to the 1980 level, using utility-wide growth factors. (This was only the case, for some utilities, of disaggregated O&M costs and plant in service data). The resulting parameters are presented in tables 6-2 through 6-6, in which quantities labeled "base-year" are allowed to change in the model and quantities not so labeled are assumed to be constant.

TABLE 6-2
BASE-YEAR MARKET DATA FOR TEN UTILITIES

Utility's Region	Market Sector		
	Residential	Commercial	Industrial
	Sales (thousands of mcf)		
N. Eng.	36,200	26,700	9,800
E.N. Centr.	102,300	51,000	44,700
Mid. Atl.	38,665	17,924	42,713
Sou. Atl.	10,300	8,600	31,700
Midwest	38,244	19,275	33,706
Southwest	61,835	36,993	240,047
Central	14,100	9,200	15,800
N. Centr.	11,736	7,753	30,338
West	282,100	94,500	550,900
N. West	6,800	6,400	20,400
Numbers of Customers			
N. Eng.	444,841	32,965	353
E.N. Centr.	1,168,800	142,466	4,826
Mid. Atl.	240,900	16,268	363
Sou. Atl.	151,597	12,048	349
Midwest	266,241	28,867	480
Southwest	624,863	66,962	1,932
Central	110,086	17,053	502
N. Centr.	89,622	11,227	513
West	3,550,680	171,767	29,862
N. West	65,963	9,488	301
Average Retail Price (\$/mcf)			
N. Eng.	5.445	4.810	4.102
E.N. Centr.	5.034	4.506	3.686
Mid. Atl.	3.416	3.223	2.630
Sou. Atl.	4.338	3.154	2.696
Midwest	2.947	2.745	2.510
Southwest	2.538	2.371	2.179
Central	2.833	2.536	2.348
N. Centr.	2.964	3.187	2.928
West	3.223	3.422	2.567
N. West	4.577	4.167	3.666

Source: 1980 COMPUSTAT data file.

TABLE 6-3
PEAK LOAD CHARACTERISTICS FOR TEN UTILITIES

Utility's Region	Monthly Peak Load Factors K_i			Daily Peak Load
	Residential	Commercial	Industrial	Factor LF
N. Eng.	0.1168	0.1059	0.0971	0.3481
E.N. Centr.	0.1634	0.1550	0.1181	0.3778
Mid. Atl.	0.1643	0.1557	0.0980	0.3510
Sou. Atl.	0.2000	0.1186	0.0833	0.6030
Midwest	0.1963	0.1969	0.1015	0.4238
Southwest	0.3223	0.1552	0.0919	0.3856
Central	0.1855	0.1800	0.0833	0.4958
N. Centr.	0.1610	0.1627	0.1070	0.4088
West	0.1417	0.1162	0.0833	0.5145
N. West	0.1623	0.1575	0.0977	0.4473

Source: Authors' calculations.

c. Gas Demand Parameters

The elasticities of the sectoral gas demands for gas, electricity, and other fuel prices are presented in tables 6-7 and 6-8. The base-year (1980) retail prices of natural gas were presented in table 6-2. The other base-year prices are presented in table 6-9, and the forecasts of these prices for 1985 by the MEFS model under the medium world oil price scenario are presented in table 6-10. It is important to note that non-gas price forecasts remain invariant in our analysis, the results of which are presented in the next section. The 1981 Annual Report to Congress prepared by the Energy Information Administration includes the 1979 actual prices and the 1985 forecasts. The 1980 prices reported in table 6-9 have been interpolated between these two values, assuming a constant rate of price increase. Finally, the demand functions multiplicative constants (in equations 57-59) are presented in table 6-11. With these constants, the values of the demand functions calculated with the 1980 prices are exactly equal to the sectoral utility gas sales presented in table 6-2.

TABLE 6-4

BASE-YEAR OPERATION AND MAINTENANCE COSTS FOR TEN UTILITIES

Utility's Region	O&M Total Costs (\$1000)						Sales & Admin. & General	City-Gate Gas Price (\$/mcf)
	Storage	Transmission	Distribution	Cust. Accts.	Cust. Servs.	Promo.		
N. Eng.	2,321	0	22,157	18,804	0	4,480	19,989	3.093
E.N. Centr.	697	78	38,388	18,042	1,956	72	29,542	2.734
Mid. Atl.	2,942	6,224	21,160	9,653	0	1,027	17,409	1.576
Sou. Atl.	0	1,923	5,557	2,652	294	254	4,671	2.406
Midwest	3,799	0	13,287	6,479	263	0	6,819	1.981
Southwest	1,321	16,044	23,299	11,343	206	480	32,826	1.632
Central	0	18	3,260	2,046	18	65	3,636	2.262
N. Centr.	249	1,146	2,806	1,478	372	133	5,554	2.489
West	19,343	19,702	93,057	61,696	0	21,175	93,913	2.837
N. West	273	0	1,462	1,213	418	37	3,309	3.395

Source: 1980 COMPUSTAT data file,
1979 Annual Reports to state regulatory commissions

TABLE 6-5

GROSS PLANTS IN SERVICE, RATE BASE RATIO (ADJ), AND ANNUAL DEPRECIATION FOR TEN UTILITIES

Utility's Region	Gross Plant in Service (\$1000)						Ratio ADJ	Annual Depreciation (\$1000)
	Manufactured Produc.	Nat. Gas Produc.	Storage	Transmission	Distribution	General		
N. Eng.	18,908	0	10,113	0	258,991	16,419	0.734	9,482
E.N. Cen.	146,179	0	11,243	25,503	770,522	5,881	0.608	42,332
Mid. Atl.	0	193,187	47,508	55,102	216,118	14,061	0.639	11,493
Sou. Atl.	8,367	0	15,299	27,878	86,458	2,207	0.686	5,241
Midwest	4,470	414	23,269	0	224,468	19,864	0.740	8,367
Southwest	0	209,289	47,032	283,336	308,049	50,120	0.678	22,478
Central	0	0	0	2,673	54,080	3,007	0.688	1,527
N. Centr.	0	100,260	36,462	58,419	41,523	5,795	0.642	6,669
West	0	0	105,752	257,470	1,320,978	52,820	0.622	63,938
N. West	0	0	12,457	0	63,519	690	0.770	1,971

Source: 1980 COMPUSTAT data file,
1979 Annual Reports to state regulatory commissions

TABLE 6-6

FINANCIAL VARIABLES FOR TEN UTILITIES

Utility's Region	Rate of Return (%)	Income Taxes (\$1000)	Revenue Taxes (\$1000)	Property Taxes (\$1000)	Gas Sales Revenues (\$1000)
N. Eng.	13.113	17,966	15,945	5,898	368,953
E.N. Centr.	11.960	31,367	99,673	36,865	910,154
Mid. Atl.	9.603	11,795	13,485	4,988	304,807
Sou. Atl.	8.687	2,487	3,274	1,211	157,643
Midwest	8.097	8,424	3,972	1,469	250,223
Southwest	13.185	42,988	12,919	4,778	767,784
Central	2.442	-892	930	344	100,398
N. Centr.	4.620	-4,527	3,124	1,155	149,394
West	7.235	51,391	46,651	17,255	3,197,440
N. West	8.184	833	3,047	1,127	132,584

Source: 1980 COMPUSTAT data file,
1979 Annual Reports to state regulatory commissions

TABLE 6-7

ELASTICITIES OF GAS DEMAND WITH RESPECT
TO GAS AND ELECTRICITY PRICES FOR TEN REGIONS

Region	Gas Price			Electricity Price		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
N. Eng.	-0.353	-0.360	-2.090	0.030	0.011	0.326
E.N. Centr.	-0.329	-0.350	-2.383	0.000	0.000	0.750
Mid. Atl.	-0.347	-0.364	-2.198	0.015	0.022	1.000
Sou. Atl.	-0.394	-0.367	-1.975	0.030	0.022	0.883
Midwest	-0.347	-0.340	-2.110	0.015	0.005	0.877
Southwest	-0.422	-0.343	-1.280	0.029	0.010	0.230
Central	-0.365	-0.343	-1.986	0.014	0.011	0.578
N. Centr.	-0.315	-0.361	-2.020	0.013	0.011	1.100
West	-0.385	-0.350	-2.432	0.016	0.000	0.443
N. West	-0.329	-0.350	-1.770	0.030	0.011	0.710

Source: MEFS documentation

TABLE 6-8

CROSS PRICE ELASTICITIES OF INDUSTRIAL GAS DEMAND
WITH RESPECT TO ALTERNATE FUELS FOR TEN REGIONS

Region	Distillate Oil	Residual Oil	Liquid Gas	Coal
N. Eng.	0.290	0.930	0.270	0.030
E.N. Centr.	0.400	0.930	0.320	0.030
Mid. Atl.	0.200	0.490	0.170	0.090
Sou. Atl.	0.180	0.650	0.160	0.053
Midwest	0.170	0.410	0.200	0.070
Southwest	0.150	0.260	0.310	0.050
Central	0.260	0.300	0.430	0.030
N. Centr.	0.090	0.400	0.310	0.070
West	0.250	0.410	1.364	0.060
N. West	0.180	0.330	0.188	0.090

Source: MEFS documentation

TABLE 6-9

BASE-YEAR (1980) ALTERNATE FUEL RETAIL PRICES FOR TEN REGIONS
(\$ per million Btu)

Region	Electricity			Industrial Distillate Oil	Industrial Residual Oil	Industrial Liquid Gas	Industrial Coal
	Residen- tial	Commer- cial	Indus- trial				
N. Eng.	17.70	17.58	13.23	5.67	4.12	4.36	2.08
E.N. Centr.	20.79	19.38	11.68	5.52	3.97	4.35	1.72
Mid. Atl.	15.04	14.63	10.11	5.47	3.96	4.44	1.45
Sou. Atl.	12.39	12.72	9.10	5.40	3.56	4.12	1.70
Midwest	14.54	14.14	9.65	5.43	3.59	4.10	1.58
Southwest	13.42	12.47	9.02	5.49	3.53	4.22	1.70
Central	14.09	13.21	9.80	5.45	3.56	3.93	1.49
N. Centr.	11.47	10.44	6.10	5.27	3.45	4.05	1.17
West	14.30	13.95	11.61	5.31	3.60	3.71	1.58
N. West	6.39	6.33	2.73	5.09	3.57	3.56	1.59

Source: EIA, op. cit.

TABLE 6-10

1985 FORECASTS OF ALTERNATE FUEL RETAIL PRICES FOR TEN REGIONS
(\$ per million Btu)

Region	Electricity			Industrial Distillate Oil	Industrial Residual Oil	Industrial Liquid Gas	Industrial Coal
	Residen- tial	Commer- cial	Indus- trial				
N. Eng.	22.44	22.31	18.00	7.55	6.20	6.11	2.73
E.N. Centr.	23.70	22.29	14.62	7.57	6.42	6.20	2.35
Mid. Atl.	16.53	16.12	11.60	7.45	6.63	6.50	1.97
Sou. Atl.	14.71	15.04	11.44	7.56	6.11	6.66	2.76
Midwest	16.86	16.46	11.98	6.98	6.16	6.20	2.06
Southwest	20.58	19.56	16.28	6.92	6.19	6.22	2.51
Central	18.39	17.51	14.13	6.90	6.22	6.04	1.75
N. Centr.	11.81	10.77	6.44	7.23	5.93	6.29	1.32
West	20.05	19.70	17.40	7.15	5.96	5.38	2.67
N. West	8.25	8.19	4.64	7.15	6.06	5.38	2.12

Source: EIA, op. cit.

TABLE 6-11

MULTIPLICATIVE CONSTANTS OF THE SECTORAL GAS DEMAND FUNCTIONS
FOR TEN UTILITIES*

Utility's Region	Residential Constant	Commercial Constant	Industrial Constant
N. Eng.	60,405,520	45,539,503	9,800,000
E.N. Centr.	174,102,530	86,376,796	13,639,356
Mid. Atl.	56,857,795	25,870,589	9,634,412
Sou. Atl.	17,026,963	12,396,012	8,017,276
Midwest	53,458,294	26,812,738	10,437,208
Southwest	84,962,171	48,501,746	136,408,340
Central	19,870,298	12,304,985	5,549,480
N. Centr.	16,009,855	11,481,140	11,638,855
West	424,226,630	145,354,940	259,806,590
N. West	10,609,014	10,334,817	36,913,676

Source: Authors' calculations

*The units of these constants are as implied by equations 57, 58, and 59.

Calibration and Testing of the Model

As indicated previously, the model was calibrated by adjusting the weights for the three customer classes in the customer allocation factors, so that, when using the 1980 utility parameters, the calculated equilibrium retail prices converge with the actual 1980 retail prices. Tables 6-12 and 6-13 present the actual and calculated gas prices and sales. A comparison of tables 6-12 and 6-13 shows that except for the Southwest and West regions, the equilibrium model is able to replicate the actually observed prices quite accurately, with an average difference of less than 1 percent.

A further test of the validity of the model was performed by computing the equilibrium retail prices resulting from the actual 1982 city-gate prices, and by comparing these computed prices to the actually observed 1982 retail prices.⁸ While the model may either overestimate or underestimate the retail prices, depending upon the customer class and the utility/region, the average of the absolute values of the percentage price deviations varies from 7 percent (residential prices) to 7.5 percent (commercial and industrial prices). When using the actual percentage price deviations, these averages turn out to be equal to -1.74 percent for the residential sector, -2.37 percent for the commercial sector, and -1.23 percent for the industrial sector. The general trend towards underestimation may be explained by the use, in the model, of the 1980 plant-in-service data, without adjustment for the plant added in 1981 and 1982 simply to replace the plant normally retired during the same period. As the retired plant is accounted for at its original cost, and the corresponding replacement plant at its current cost, the plant-in-service value is bound to increase, even in the absence of

⁸The 1982 price data were gathered through telephone and mail contacts with the ten utilities selected. These data are presented in chapter 7, table 7-3.

TABLE 6-12

ACTUAL 1980 GAS PRICES AND SALES FOR TEN UTILITIES

Utility's Region	Natural Gas Prices (1980 \$/mcf)			Annual Gas Sales (thousands of mcf)		
	Resi- dential	Commer- cial	Indus- trial	Resi- dential	Commer- cial	Indus- trial
N. Eng.	5.45	4.81	4.10	36,200	26,700	9,800
E.N. Centr.	5.03	4.51	3.67	102,300	51,000	44,700
Mid. Atl.	3.42	3.22	2.63	38,665	17,924	42,713
Sou. Atl.	4.34	3.15	2.70	10,300	8,600	31,700
Midwest	2.95	2.74	2.51	38,244	19,275	33,706
Southwest	2.54	2.37	2.18	61,835	36,993	240,047
Central	2.83	2.54	2.35	14,100	9,200	15,800
N. Centr.	2.96	3.19	2.93	11,736	7,753	30,338
West	3.22	3.42	3.57	282,100	94,500	550,900
N. West	4.58	4.17	3.67	6,800	6,400	20,400

Source: 1980 COMPUSTAT data file

TABLE 6-13

CALCULATED 1980 GAS PRICES AND SALES FOR TEN UTILITIES

Utility's Region	Natural Gas Prices (1980 \$/mcf)			Natural Gas Sales (thousands of mcf)		
	Resi- dential	Commer- cial	Indus- trial	Resi- dential	Commer- cial	Indus- trial
N. Eng.	5.52	4.92	4.14	36,018	26,480	9,641
E.N. Centr.	5.03	4.50	3.73	102,348	51,039	43,362
Mid. Atl.	3.07	3.08	2.63	40,130	18,230	42,720
Sou. Atl.	4.44	3.21	2.73	10,211	8,551	30,867
Midwest	2.95	2.75	2.51	38,220	19,269	33,612
Southwest	2.80	2.57	2.31	59,302	36,008	222,346
Central	2.83	2.53	2.35	14,096	9,204	15,772
N. Centr.	3.06	3.19	2.93	11,624	7,751	30,182
West	3.38	3.59	3.73	277,116	92,964	495,485
N. West	4.58	4.16	3.67	6,800	6,400	20,399

Source: Model output

market expansion. Another source of discrepancy is the difference between the actually achieved rates of return in 1980 and 1982. Indeed, the use, in the model, of the 1980 rate of return may lead to underestimation or overestimation of the 1982 earnings. Despite these approximations, the test results confirm the usefulness of the model.

Effects of Federal Wellhead Pricing Policy

The previous section presented the NRRI equilibrium model of a distribution utility designed to analyze the effects of various federal and state natural gas pricing policies on retail rates. This section contains the results of the analyses of federal wellhead pricing policy.

In examining the consequences of federal wellhead pricing policies, the equilibrium model was first used to estimate retail rates for the range of forecasted city-gate prices identified in chapter 5. The resulting retail rates and sales are presented in the first part of this section. Federal wellhead pricing policy effects are examined next in the context of natural gas market conditions.

Effects of Various City-Gate Price Increases

The overall range of expected 1980-to-1985 city-gate real price increases reported here is from approximately 50 to 125 percent. The precise values for the lower end of this range were those reported for the medium world oil price scenario in the 1981 Annual Report to Congress (ARC81). In some regions the increase was larger than 50 percent and in some regions it was less. These values were 45 percent for the New England region, 43 percent for the East North Central region, 53 percent for the Middle Atlantic region, 55 percent for the South Atlantic region, 64 percent for the Midwest region, 60 percent

for the Southwest region, 60 percent for the Central region, 66 percent for the North Central region, 88 percent for the West region, and 65 percent for the North West region. In addition to the lower and upper values, two intermediate values of price increases were studied by the NRRI study team: 75 percent and 100 percent. This set of possible city-gate real price increases covers the entire range of forecasts reviewed in chapter 5 in light of the recent decline in the demand for natural gas.

These price increases, however, do not correspond well to particular decontrol alternatives, as discussed in the previous chapter. The strategy here is, therefore, to estimate end-user prices for this range of city-gate price increases first. Next, the resulting changes in retail rates and sales are related to the differences between a policy of partial and total decontrol. In particular, the difference between a 100 and 125 percent city-gate price increase can be interpreted as the difference between a policy of partial versus total decontrol under normal market conditions. The difference between an increase of 75 to 100 percent can be associated with the difference between these two policies under somewhat slacker market conditions.

In the first step, each of the four levels of city-gate price increases was examined with the model for each region. Each model run produced expected 1985 retail rates and sales for the three customer classes--residential, commercial, and industrial. The results are presented in tables 6-14 through 6-17, each corresponding to a different level of city-gate price increase.

It is important to recall that the 1985 prices in these tables are reported in 1980 dollars. If these forecasts are correct, CPI inflation will result in higher nominal prices in 1985. For example,

TABLE 6-14

1985 NATURAL GAS RETAIL PRICES AND SALES FOR TEN UTILITIES WITH
1985 CITY-GATE PRICES AS PROJECTED IN ARC81*

Utility's Region	Projected 1985 City- Gate Price (1980 \$/ mcf)	Projected 1985 Gas Retail Prices (1980 \$/mcf)				Projected 1985 Gas Sales (mmcf)			
		Resi- dential	Commer- cial	Indus- trial	Weighted Average	Resi- dential	Commer- cial	Indus- trial	Total
N. Eng.	4.48	7.13	6.50	5.61	6.68	33,157	24,022	9,897	67,076
E.N. Centr.	3.91	6.47	5.90	5.07	5.97	94,216	46,408	49,708	190,332
Mid. Atl.	2.41	4.08	4.09	3.63	3.90	36,415	16,475	36,363	89,253
Sou. Atl.	3.73	5.94	4.62	4.10	4.56	9,145	7,507	28,322	44,974
Midwest	3.25	4.35	4.12	3.97	4.18	33,498	16,806	22,380	72,684
Southwest	2.61	3.86	3.63	3.33	3.45	52,477	32,124	220,360	304,961
Central	3.62	4.25	3.91	3.72	3.97	12,208	7,952	11,866	32,026
N. Centr.	4.13	5.14	5.31	5.01	5.11	9,869	6,450	16,443	32,762
West	5.33	5.97	6.23	6.44	6.26	233,705	76,606	355,743	666,054
N. West	5.60	6.95	6.50	5.94	6.25	5,972	5,492	17,743	29,207

Source: Model output and authors' calculations

*The projected 1985 city-gate prices in ARC81 were about 50 percent higher than 1980 city-gate prices.

TABLE 6-15

1985 NATURAL GAS RETAIL PRICES AND SALES FOR TEN UTILITIES WITH
A 75 PERCENT REAL INCREASE IN CITY-GATE PRICE FROM 1980 TO 1985

Utility's Region	Projected 1985 City- Gate Price (1980 \$/ mcf)	Projected 1985 Gas Retail Prices (1980 \$/mcf)			Weighted Average	Projected 1985 Gas Sales (mmcf)			Total
		Resi- dential	Commer- cial	Indus- trial		Resi- dential	Commer- cial	Indus- trial	
N. Eng.	5.41	8.20	7.55	6.75	7.80	31,566	22,758	6,728	61,052
E.N. Centr.	4.78	7.58	7.00	6.14	7.15	89,421	43,727	31,474	164,622
Mid. Atl.	2.76	4.56	4.56	4.27	4.46	35,039	15,827	25,477	76,343
Sou. Atl.	4.21	6.49	5.15	4.63	5.16	8,836	7,215	22,303	38,354
Midwest	3.47	4.59	4.35	4.27	4.44	32,877	16,488	19,175	68,540
Southwest	2.86	4.16	3.91	3.62	3.75	50,845	31,296	197,694	279,385
Central	3.96	4.59	4.26	4.07	4.33	11,864	7,725	9,948	29,537
N. Centr.	4.36	5.41	5.57	5.29	5.39	9,716	6,339	14,731	30,786
West	4.69	5.57	5.83	5.97	5.83	229,710	78,403	428,854	736,967
N. West	5.94	7.31	6.86	6.30	6.63	5,873	5,390	15,998	27,261

Source: Model output and authors' calculations

TABLE 6-16

1985 NATURAL GAS RETAIL PRICES AND SALES FOR TEN UTILITIES WITH
A 100 PERCENT REAL INCREASE IN CITY-GATE PRICE FROM 1980 TO 1985

Utility's Region	Projected 1985 City- Gate Price (1980 \$/ mcf)	Projected 1985 Gas Retail Prices (1980 \$/mcf)			Weighted Average	Projected 1985 Gas Sales (mmcf)			Total
		Resi- dential	Commer- cial	Indus- trial		Resi- dential	Commer- cial	Indus- trial	
N. Eng.	6.19	9.08	8.42	7.71	8.71	30,432	21,881	5,085	57,398
E.N. Centr.	5.47	8.44	7.84	6.97	8.05	86,327	42,022	23,239	151,588
Mid. Atl.	3.15	5.09	5.09	5.05	5.08	33,722	15,206	17,612	66,540
Sou. Atl.	4.81	7.17	5.81	5.29	5.89	8,496	6,983	17,139	32,618
Midwest	3.96	5.13	4.89	4.97	5.03	31,623	15,850	13,910	61,383
Southwest	3.26	4.65	4.39	4.11	4.25	48,478	30,086	168,030	246,594
Central	4.52	5.17	4.83	4.65	4.92	11,362	7,398	7,645	26,405
N. Centr.	4.98	6.13	6.30	6.07	6.14	9,340	6,065	11,153	26,558
West	5.67	6.34	6.60	6.90	6.66	218,612	75,077	301,185	594,874
N. West	6.79	8.22	7.76	7.20	7.57	5,652	5,162	12,644	23,458

Source: Model output and authors' calculations

TABLE 6-17

1985 NATURAL GAS RETAIL PRICES AND SALES FOR TEN UTILITIES WITH
A 125 PERCENT REAL INCREASE IN CITY-GATE PRICE FROM 1980 TO 1985

Utility's Region	Projected 1985 City- Gate Price (1980 \$/ mcf)	Projected 1985 Gas Retail Prices (1980 \$/mcf)				Projected 1985 Gas Sales (mmcf)			
		Resi- dential	Commer- cial	Indus- trial	Weighted Average	Resi- dential	Commer- cial	Indus- trial	Total
N. Eng.	6.96	9.97	9.29	8.70	9.61	29,454	21,123	3,955	54,532
E.N. Centr.	6.15	9.29	8.67	7.81	8.93	83,652	40,562	17,761	141,975
Mid. Atl.	3.55	5.61	5.61	5.91	5.67	32,602	14,678	12,424	59,704
Sou. Atl.	5.41	7.85	6.47	5.95	6.62	8,197	6,636	13,584	28,417
Midwest	4.46	5.67	5.43	5.72	5.61	30,542	15,301	10,342	56,185
Southwest	3.67	5.15	4.86	4.60	4.75	46,456	29,045	145,484	220,985
Central	5.09	5.75	5.41	5.23	5.52	10,929	7,118	6,058	24,105
N. Centr.	5.60	6.84	7.02	6.86	6.89	9,021	5,833	8,721	23,575
West	6.38	7.10	7.37	7.87	7.47	209,228	72,240	218,480	499,948
N. West	7.64	9.12	8.66	8.09	8.50	5,461	4,967	10,272	20,700

Source: Model output and authors' calculations

in table 6-14 the New England city-gate price in 1985 is given as \$4.48 per mcf in 1980 dollars. Since consumer prices rose 17% from 1980 to 1982, this value is \$5.24 per mcf in 1982 dollars. Depending on the additional inflation that occurs from 1982 to 1985, the actual numbers that appear on 1985 tariffs could be substantially above the 1980-value prices in these tables.

Each table contains, for the 10 regional utilities, two sets of information: the expected natural gas prices and the expected natural gas sales. The following prices are reported: the city-gate price that was input to the model, the residential retail price, the commercial retail price, the industrial retail price, and the weighted average retail price with weights equal to the annual gas sales of the three sectors. Hence, gas sales are reported in the tables for each customer class as well as for the whole utility.

Tables 6-14 through 6-17 form the basis of the analysis that follows. With the results presented in these tables and the base case data in table 6-13, the percent changes in retail rates and sales due to city-gate price increases were calculated. These percent changes for residential, commercial, and industrial customers are presented in tables 6-18, 6-19, and 6-20, respectively.

Table 6-18 shows that the increases in the city-gate price have the minimal impact on the residential rate for the utility in the South Atlantic region. In contrast, the impact is quite significant for the utility in the North Central region: the expected retail rate would double if the city-gate price increases by 100 percent. Table 6-18 also shows that the impact on residential loads is minimal for the utilities in the New England and the East North Central regions. This is because these two regional utilities have predominantly residential demand (residential market shares for both utilities are over 50 percent), and hence the response to changing prices is inelastic. Table 6-19 contains results for the commercial sector, which are similar to the results for the residential sector.

TABLE 6-18

PERCENT CHANGES IN RESIDENTIAL PRICES AND SALES FOR TEN UTILITIES DUE TO
THE REAL CITY-GATE PRICE INCREASES OF ARC81 AND OF 75%, 100%, and 125% FROM 1980 TO 1985

Utility's Region	Percent Change in Price				Percent Change in Sales			
	ARC81 Increases	75% Increase	100% Increase	125% Increase	ARC81 Increases	75% Increase	100% Increase	125% Increase
N. Eng.	29	49	64	81	-8	-12	-16	-18
E.N. Centr.	29	51	68	85	-8	-13	-16	-18
Mid. Atl.	33	49	66	83	-9	-13	-16	-19
Sou. Atl.	34	46	61	77	-10	-13	-17	-20
Midwest	47	56	74	92	-12	-14	-17	-20
Southwest	38	49	66	84	-12	-14	-18	-22
Central	50	62	83	103	-13	-16	-19	-22
N. Centr.	68	77	100	124	-15	-16	-20	-22
West	77	65	88	110	-16	-17	-21	-24
N. West	52	60	79	99	-12	-14	-17	-20

Source: Authors' calculations

TABLE 6-19

PERCENT CHANGES IN COMMERCIAL PRICES AND SALES FOR TEN UTILITIES DUE TO
THE REAL CITY-GATE PRICE INCREASES OF ARC81 AND OF 75%, 100%, AND 125% FROM 1980 TO 1985

Utility's Region	Percent Change in Price				Percent Change in Sales			
	ARC81 Increases	75% Increase	100% Increase	125% Increase	ARC81 Increases	75% Increase	100% Increase	125% Increase
N. Eng.	32	53	71	89	-9	-14	-17	-20
N.E. Centr.	31	56	74	93	-9	-14	-18	-21
Mid. Atl.	33	48	65	82	-10	-13	-17	-19
Sou. Atl.	44	60	81	102	-12	-16	-18	-22
Midwest	50	58	78	97	-13	-14	-18	-21
Southwest	41	52	71	89	-11	-13	-16	-19
Central	55	68	91	114	-14	-16	-20	-23
N. Centr.	66	75	97	120	-17	-18	-22	-25
West	74	62	84	105	-18	-16	-19	-22
N. West	56	65	87	108	-14	-16	-19	-22

Source: Authors' calculations

TABLE 6-20

PERCENT CHANGES IN INDUSTRIAL PRICES AND SALES FOR TEN UTILITIES DUE TO
THE REAL CITY-GATE PRICE INCREASES OF ARC81 AND OF 75%, 100%, AND 125%, FROM 1980 TO 1985

Utility's Region	Percent Change in Price				Percent Change in Sales			
	ARC81 Increases	75% Increase	100% Increase	125% Increase	ARC81 Increases	75% Increase	100% Increase	125% Increase
N. Eng.	36	63	86	110	3	-30	-47	-59
E.N. Centr.	36	65	87	109	15	-27	-46	-59
Mid. Atl.	38	62	92	125	-15	-40	-59	-71
Sou. Atl.	50	70	94	118	-8	-28	-44	-56
Midwest	58	70	98	128	-33	-43	-59	-69
Southwest	44	57	78	99	-1	-11	-24	-35
Central	58	73	98	123	-25	-37	-52	-62
N. Centr.	71	81	107	134	-46	-51	-63	-71
West	73	60	85	111	-28	-13	-39	-56
N. West	62	72	96	120	-13	-22	-38	-50

Source: Authors' calculations

Table 6-20 shows that the increase in the industrial rate is the smallest for the utility in the Southwest region, while for the utility in the North Central region it is the largest. The loss of industrial loads is minimal for the utility in the Southwest region, as indicated in table 6-20. For the Southwest utility, the market mix is predominantly industrial (over 70 percent), and there is a heavy reliance on natural gas versus alternate fuels, presumably because customers are close to the gas fields, incurring relatively small transportation costs. As a result, the (own and cross) price elasticities of gas demand (tables 6-7 and 6-8) are small, so industrial load loss is limited. In contrast, the utilities in the North Central, Middle Atlantic, and Midwest regions would experience a serious loss of industrial loads.

Expected average annual residential gas bills are reported in table 6-21. Bill increases are less than price increases because price increases cause a decrease in consumption, and bills are, of course, a product of price and consumption. One benefit of the equilibrium model is its ability to handle conservation effects. The first column of the table contains the reference year (1980) gas bills for the 10 regional utilities. The remainder of the table contains the expected 1985 residential gas bills for the four levels of city-gate price increase. Both the 1985 value of the bills and the percent change in that value from the reference year are reported. Table 6-21 shows that the annual residential gas bill would be least affected by the increases in the city-gate price for the utility in the South Atlantic region. This is apparent from the data presented in table 6-18, showing that the increase in the retail rate is the smallest for this utility, and the decrease in gas demand is the second smallest. The largest impact on residential gas bills is expected for the utility in the North Central region, as indicated in table 6-21.

TABLE 6-21

ANNUAL RESIDENTIAL NATURAL GAS BILLS IN 1980 AND 1985 FOR TEN UTILITIES FOR
VARIOUS INCREASES IN REAL CITY-GATE PRICES, EXPRESSED IN 1980 DOLLARS

Utility's Region	1985 ANNUAL RESIDENTIAL NATURAL GAS BILL								
	1980 Bill	ARC81 City-Gate Price Increases		75% City-Gate Price Increase		100% City-Gate Price Increase		125% City-Gate Price Increase	
		Bill	% Change	Bill	% Change	Bill	% Change	Bill	% Change
N. Eng.	447	531	19	582	30	621	39	660	48
E.N. Centr.	440	522	19	580	32	623	42	665	51
Mid. Atl.	511	617	20	663	30	713	40	759	49
Sou. Atl.	299	358	20	378	26	402	34	424	42
Midwest	423	547	29	567	34	609	44	650	54
Southwest	266	324	22	339	27	361	36	383	44
Central	362	471	30	495	37	534	48	571	58
N. Centr.	397	566	43	587	48	639	61	688	73
West	264	376	42	360	36	390	48	418	58
N. West	472	629	33	651	38	704	49	755	60

Source: Authors' calculations

The Effect of Partial Versus Total Decontrol

The following discussion relates the changes in retail rates and sales to federal wellhead pricing policy alternatives. Specifically, the effect on retail rates and annual residential gas bills of the choice between policies of partial and total decontrol is analyzed considering natural gas market conditions. As previously discussed, these policies yield city-gate price increase differences of about 25 percentage points. Hence, comparisons of expected retail rates and residential gas bills between a 75 and 100 percent city-gate price increase and between a 100 and 125 percent city-gate price increase are of interest and are contained in table 6-22.

The data in table 6-22 can be interpreted as the percentages by which rates under total decontrol of wellhead prices would exceed rates under the NGPA in 1985. If the market is rather slack (corresponding to the difference between a 75 and 100 percent city-gate price increase), the expected residential rate differences between policies of partial and total decontrol range from 11 percent for the utilities in the New England, East North Central, and South Atlantic regions to 14 percent for the utility in the West region. Thus, the variations in rate differences among regions are not very significant (about 1 to 2 percentage points). The regional variations in expected commercial rate differences are even smaller, as indicated in the third column of table 6-22, with five of the regional utilities expected to experience a 12 percent higher commercial rate under total decontrol and the remainder a 13 percent higher rate. For industrial customers, expected rate hikes are somewhat higher (2 or 3 percentage points) than those for residential and commercial customers. They range from 14 percent for the utilities in New England, East North Central, South Atlantic, Southwest, Central, and North West to 18 percent for the utility in the Middle Atlantic region. The column

TABLE 6-22

PERCENT DIFFERENCES IN 1985 RETAIL PRICES AND ANNUAL RESIDENTIAL
 BILLS COMPARING 75% VERSUS 100% REAL CITY-GATE PRICE INCREASES AND
 COMPARING 100% VERSUS 125% REAL CITY-GATE PRICE INCREASES

Utility's Region	Percent Difference in Retail Prices								Percent Difference in Annual Residential Bill	
	Residential		Commercial		Industrial		Average		75%	100%
	75% vs. 100%	100% vs. 125%	75% vs. 100%	100% vs. 125%	75% vs. 100%	100% vs. 125%	75% vs. 100%	100% vs. 125%	75% vs. 100%	100% vs. 125%
N. Eng.	11	10	12	10	14	13	12	10	7	6
E.N. Centr.	11	10	12	11	14	12	13	11	7	7
Mid. Atl.	12	10	12	10	18	17	14	12	8	6
Sou. Atl.	11	9	13	11	14	12	14	12	6	5
Midwest	12	11	12	11	16	15	13	12	7	7
Southwest	12	11	12	11	14	12	13	12	6	6
Central	13	11	13	12	14	12	14	12	8	7
N. Centr.	13	12	13	11	15	13	14	12	9	8
West	14	12	13	12	16	14	14	12	8	7
N. West	12	11	13	12	14	12	14	12	8	7

Source: Authors' calculations

labeled "Average" in table 6-22 gives the expected percent differences in average retail rates. They range from 12 percent for the utility in New England to 14 percent for the utilities in the following six regions: Middle Atlantic, South Atlantic, Central, North Central, West, and North West. Again, the variations among regions are not very significant (about 1 to 2 percentage points), with the difference averaging about 13 percent for slack market conditions.

While the residential rate increase due to a policy of total decontrol versus one of partial decontrol under slack demand conditions is expected to be about 13 percent, the expected increase in the annual gas bill is only about 8 percent, because the higher rate results in a decline in load. The expected magnitude of this demand reduction is (from the annual sales data presented in tables 6-15 and 6-16) about 4 to 5 percent. The expected increases in residential gas bills range from 6 percent for the utilities in the South Atlantic and Southwest regions to 9 percent for the utility in the North Central region.

If the market demand for natural gas is not slack (i.e., normal), then the effect on retail rates and residential gas bills of changing federal policy from partial to total decontrol can be examined by comparing the differences between 100 and 125 percent city-gate price increases. These comparisons can be found in the 2nd, 4th, 6th, 8th, and 10th columns of table 6-22. It appears that the effects on retail rates and on residential gas bills are similar to those observed in the slack market case. The percentage change, however, is approximately 1 to 2 percentage points smaller. This is because the differences are measured at the 100 percent price increase level, which is itself higher than the 75 percent level used to measure the rate effect under the slacker market assumption. The residential rate differences are 9 percent for the utility in the South Atlantic region, and 12 percent for the utilities in the North Central and West regions. For commercial customers, the rate increases range from 10

percent for the utilities in New England and Middle Atlantic regions to 12 percent for the utilities in the Central and West regions. As in the case of slacker market conditions, the rate increases for industrial customers are about 2 percentage points higher than those for the residential and commercial customers. They range from 12 percent for the utilities in the East North Central, South Atlantic, Southwest, Central, and North West regions to 17 percent for the utility in the Middle Atlantic region. The expected increases in the residential gas bills range from 5 percent for the utility in the South Atlantic region to 8 percent for the utility in the North Central region. The level of expected increase in gas bills is about 4 percentage points lower than that of the expected residential rate increase.

An important parameter for state utility commissions is the fraction of the average retail price contributed by the gas cost at the city gate. This fraction, reported in table 6-23, is the purchased gas component of retail price. It may be noted that, for some utilities, this fraction remains fairly constant with increasing city-gate price. This is because an increase in price results in a decrease in gas demand, which tends to lower the ratio of purchased gas cost to total distribution system cost. The offsetting effects of rising gas costs and decreasing demand can result in a roughly constant ratio.

This ratio represents a measure of the degree of control by state commissions over retail rates. It can be seen that, except for the utilities in the Middle Atlantic, East North Central, and New England regions, the cost of purchased gas will be more than 75 percent of the 1985 retail cost. For the utilities in the Central and North West regions, this fraction is expected to be higher than 90 percent, leaving only about 10 percent or less of their total cost subject to the control of the state commissions. (The ratios for 1982 are given in chapter 7, table 7-3.)

TABLE 6-23

RATIOS OF CITY-GATE PRICES TO AVERAGE RETAIL
PRICES IN 1985 FOR VARIOUS 1980-1985 CITY-GATE
PRICE INCREASES

Utility's Region	ARC81 Price Increases	75% Price Increase	100% Price Increase	125% Price Increase
N. Eng.	0.671	0.694	0.711	0.724
E.N. Centr.	0.656	0.669	0.680	0.689
Mid. Atl.	0.618	0.619	0.620	0.626
Sou. Atl.	0.818	0.817	0.817	0.817
Midwest	0.778	0.781	0.787	0.795
Southwest	0.756	0.763	0.767	0.773
Central	0.912	0.915	0.918	0.922
N. Centr.	0.809	0.810	0.811	0.813
West	0.851	0.851	0.852	0.855
N. West	0.896	0.896	0.897	0.899

Source: Authors' calculations.

Effects of State Cost Allocation Policy

The effect on 1985 retail rates of state policy options is considered here. Specifically, the model is used first to estimate the effect on retail rates of using two different traditional demand cost allocation methods, the peak responsibility method and the average-and-excess demand method. The purpose of this analysis is to examine state commissions' ability to mitigate against rising retail rates using such traditional methods. Then, the effect of relieving industrial customers of some or all of the costs of supporting the local distribution system is analyzed, particularly the consequences

for industrial fuel switching and for prices and sales. This analysis is based on the assumption that state commissions are not constrained by traditional cost allocation procedures in setting rates. Lastly, the ability of the model to deal with sudden, large losses of load is discussed.

Traditional Demand Cost Allocation Methods

So far the analysis has focused on the effects of federal policies on retail rates and sales. The effect of altering traditional cost allocation procedures, one of the options open to state public utility commissions to control prices, is examined and discussed in this section.

Among the various methods generally accepted for allocating demand-related costs, the peak responsibility (PR) method and the average-and-excess demand (AED) method are considered here. The analysis must be restricted to these two methods because of the limited availability of utility load data. The capability of using either method in allocating demand costs was incorporated into the distribution utility equilibrium model.

Table 6-24 shows, for each regional utility, the expected 1985 retail rates using these two demand cost allocation methods. The assumed level of city-gate price increase between 1980 and 1985 is 100 percent. As one can see from the table, the rate differences using these two demand cost allocation methods are relatively small. The industrial rate differences range from 1 cent per mcf, which is about 0.2 percent of the industrial retail rate, for the utilities in the Southwest and Central regions to 28 cents per mcf (6 percent of the retail rate) for the utility in the Middle Atlantic region. The results for the other cases of city-gate price increases show very similar trends; they are presented in appendix F. These results demonstrate that, with the traditional cost-of-service approach to

TABLE 6-24

PROJECTED 1985 RETAIL PRICES USING TWO DEMAND COST ALLOCATION METHODS WITH A 100 PERCENT REAL INCREASE IN CITY-GATE PRICES

Util- ity's Region	1985 Natural Gas Price (1980 \$/mcf)					
	Residential		Commercial		Industrial	
	AED Method	PR Method	AED Method	PR Method	AED Method	PR Method
N. Eng.	9.08	9.00	8.42	8.49	7.71	7.93
E.N. Cen.	8.44	8.42	7.84	7.84	6.97	7.05
Mid. Atl.	5.09	5.05	5.09	5.08	5.05	5.33
Sou. Atl.	7.17	6.90	5.81	5.78	5.29	5.36
Midwest	5.13	5.11	4.89	4.87	4.97	5.04
Southwest	4.65	4.64	4.39	4.38	4.11	4.10
Central	5.17	5.16	4.83	4.82	4.65	4.66
N. Centr.	6.13	6.09	6.30	6.25	6.07	6.14
West	6.34	6.26	6.60	6.59	6.90	6.77
N. West	8.22	8.16	7.76	7.71	7.20	7.24

Source: Model output.

rate setting, as city-gate prices increase in the future altering cost allocations among customer classes will have a very limited effect on retail rates for gas.

Nontraditional Industrial Cost Reallocation

The previous analysis shows that state commissions' future ability to shield industrial customers from rising city-gate prices,

by altering traditional cost allocation procedures, will be quite limited. In the face of rising wholesale prices, this could be a serious problem because large industrial customers generally have alternate fuel capability. Higher rates can lead to fuel switching and the loss of such customers. Consequently, the distribution utility's fixed costs may have to be paid by fewer customers, resulting in even higher rates for these remaining residential, commercial, and industrial customers.

In the analysis that follows, the effect on retail rates and sales resulting from the reallocation of industrial costs is considered. In other words, the ability of state commissions to shield industrial customers from rising wholesale prices is examined under the assumption that commissions are not constrained by traditional cost allocation procedures in setting rates. Two levels of industrial cost reallocation were considered in the present study: 50 percent and 100 percent. A 100 percent reallocation represents a situation in which industrial customers are relieved of all of the costs of supporting the distribution system. That is, the industrial retail price equals the city-gate price plus a gross receipts tax. For the 50 percent cost reallocation, half the cost of supporting the distribution system is shifted from the industrial to other customers. The effects on the expected retail rates and sales of these cost reallocations are presented in tables 6-25 and 6-26. In these tables, a 100 percent city-gate price increase from 1980 to 1985 is assumed. The conclusions do not change significantly if the city-gate price increase is different from this, as shown by the data in appendix F. The analysis is done in terms of 1985 prices for two reasons: one, to take advantage of the equilibrium model, which is set up to forecast 1985 retail rates; and two, to give perspective on the severity of certain problems in the near-term future.

TABLE 6-25

PERCENT CHANGE IN RETAIL PRICES AND ANNUAL SALES
DUE TO A 100 PERCENT INDUSTRIAL COST REALLOCATION
WITH A 100 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	Percent Change in Price				Percent Change in Sales			
	Resi- dential	Com- mercial	Indus- trial	Average	Resi- dential	Com- mercial	Indus- trial	Average
N. Eng.	2	2	-16	-1	-1	-1	21	3
E.N. Centr.	2	2	-12	-1	-1	-1	19	5
Mid. Atl.	17	17	-35	-5	-5	-6	154	37
Sou. Atl.	7	8	-7	-1	-3	-3	16	7
Midwest	6	7	-19	-2	-2	-2	56	11
Southwest	50	54	-19	-2	-16	-14	32	17
Central	1	1	-2	0	0	0	4	1
N. Centr.	14	13	-16	-2	-4	-4	43	16
West	24	23	-17	-2	-8	-7	55	24
N. West	4	4	-3	0	-1	-1	6	3

Source: Authors' calculations.

If a 100 percent reallocation is in effect, the industrial rate decrease varies from 2 percent for the utility in the Central region to 35 percent for the utility in the Middle Atlantic region as indicated in table 6-25. The table also shows that the accompanying increase in expected industrial demand varies from 4 percent for the utility in the Central region to 154 percent for the utility in the Middle Atlantic region. For the utility in the Central region, the practice of industrial cost reallocation has minimal effect on retail

TABLE 6-26

PERCENT CHANGE IN RETAIL PRICES AND ANNUAL SALES
DUE TO A 50 PERCENT INDUSTRIAL COST REALLOCATION
WITH A 100 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	Percent Change in Price				Percent Change in Sales			
	Resi- dential	Com- mercial	Indus- trial	Average	Resi- dential	Com- mercial	Indus- trial	Average
N. Eng.	1	1	-9	0	0	0	11	2
E.N. Centr.	1	1	-6	0	0	0	9	2
Mid. Atl.	6	6	-22	-1	-2	-2	73	15
Sou. Atl.	3	4	-4	0	-1	-1	8	3
Midwest	3	3	-11	-1	-1	-1	28	6
Southwest	21	23	-10	-1	-8	-7	15	8
Central	0	0	-1	0	0	0	2	0
N. Centr.	6	6	-9	-1	-2	-2	21	8
West	10	10	-9	-1	-4	-3	27	12
N. West	2	2	-2	0	-1	-1	3	1

Source: Authors' calculations.

rates and sales, because the cost of purchased gas is 92 percent of the utility's total costs in 1985 (as shown in table 6-23). In contrast, the effect of cost reallocation is very significant for the utility in the Middle Atlantic region, since in 1985 about 62 percent of its total cost is contributed by the cost of purchased gas, leaving 38 percent of its total cost subject to this cost reallocation practice. For most utilities, an industrial rate reduction of 12 to 19 percent is expected, while the increase in industrial demand is expected to be 16 to 56 percent.

Table 6-25 also shows that expected residential and commercial rates go up as a result of the cost reallocation. The effect is minimal for the utility in the Central region; both the residential and commercial rates increase by about 1 percent. But, for the utility in the Southwest region the effect on residential and commercial rates is quite significant (50 percent and 54 percent increases, respectively). This is because of the large industrial market share. From table 6-16, the 1985 industrial market share is expected to be about 68 percent of the utility's total sales (i.e., $168,030/246,594 = 0.682$) before any industrial cost reallocation. Consequently, any industrial cost reallocation imposes a large cost on a relatively small segment of the market. For other utilities, the residential rate increase is expected to range from 4 percent to 24 percent, and the effect on commercial customers is similar. In table 6-25, the column labeled "Average" shows the effect of cost reallocation on the average retail rate. In the case of a 100 percent cost reallocation, the average rate decrease ranges from 0 percent for the utilities in North West and Central to 5 percent for the utility in the Middle Atlantic region. The corresponding changes in expected total sales are shown in table 6-25, in the column labeled "Average." They range from a 1 percent increase in total sales for the utility in the Central region to a 37 percent increase for the utility in the Middle Atlantic region.

The effects of a 50 percent cost reallocation are shown in table 6-26. The industrial rate decrease varies from 1 percent for the utility in the Central region to 22 percent in the Middle Atlantic region; the corresponding increase in expected industrial demand ranges from 2 percent for the utility in the Central region to 73 percent for the utility in the Middle Atlantic region. For most utilities, an industrial rate reduction of 4 to 11 percent is expected, and the increase in industrial load would range from 3 percent to 28 percent. The resulting rate increase for residential and commercial customers is as low as 1 percent for the utilities

in the New England and East North Central regions and as high as 23 percent for the utility in the Southwest region. For most utilities, the increase in residential and commercial rates is expected to be somewhere between 3 percent and 10 percent, the average retail rate changes by about 1 to 2 percent, and total sales increase by 2 to 12 percent.

In general, the effect on expected retail rates and sales of shifting 50 percent of industrial costs to other customers is similar to that observed in the 100 percent reallocation case, but smaller in magnitude. In either case, the results are often much larger than those obtained by altering traditional cost allocation procedures. As mentioned, appendix F presents the results for some levels of 1985 city-gate price increases other than 100 percent.

The Importance of Catastrophic Load Loss

An important result of this gas distributor equilibrium analysis is that a reallocation of fixed cost from industrial to nonindustrial users succeeds in lowering the price paid by the industrial sector but only at the expense of higher nonindustrial prices. That is, the residential and commercial price changes in tables 6-25 and 6-26 and in appendix F are all positive, indicating increasing prices. Therefore, the numerical examples in this study indicate that state commissions always must contend with a trade-off between gas rates in the industrial and nonindustrial sectors. If the model is accurate, it is not typically possible to lower both industrial and nonindustrial prices merely by shifting the allocation of fixed costs.

This conclusion stands in sharp contrast to the widespread conventional wisdom in the industry that lowering gas rates for industrial customers will prevent them from leaving the system and thereby relieve residential and commercial consumers from the need of

assuming the fixed cost burden previously borne by the now departed large-scale user. The implication is, of course, that nonindustrial prices also will be lower. The purpose of the following discussion is to reconcile and explain these two quite different types of qualitative conclusions.

The NRRI model is based upon a representation of demand curves that might be called well-behaved. In particular, the demand curves are smooth so that as the industrial price increases, industrial load is lost in a continuous, smooth fashion. In these circumstances, the result of decreasing the industrial price is a smooth increase in the residential price. If, however, a small increase in the industrial price results in a large, discontinuous decrease in industrial load (due to the loss of a major industrial user, for example), the residential price will also rise in a discontinuous fashion. Further increases in the industrial price, however, are likely to cause residential prices to drop in a smooth manner, eventually reducing residential prices below the level that had been attained just prior to the discontinuous, upward jump.

One extreme version of this phenomenon occurs when the demand curve consists of a series of discontinuous steps as shown in figure 6-3.

The relationship of industrial to residential prices that corresponds to the demand curve in figure 6-3 is shown in figure 6-4. Beginning at point A in both diagrams, as fixed costs are reallocated from industrial to residential users, industrial prices decline. Along a conventional portion of the demand curve such as the segment between points A and B in figure 6-3 (that is, not horizontal), as industrial prices decline residential prices increase. Hence, the result of the fixed cost reallocation, which reduces industrial prices, is shown in figure 6-4 as a negative sloping segment of the sawtooth relationship, such as the line between points A and B. As

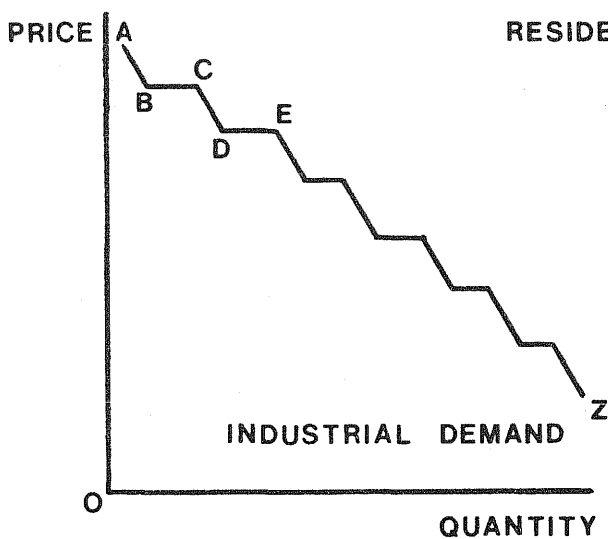


Fig. 6-3 A discontinuous demand curve

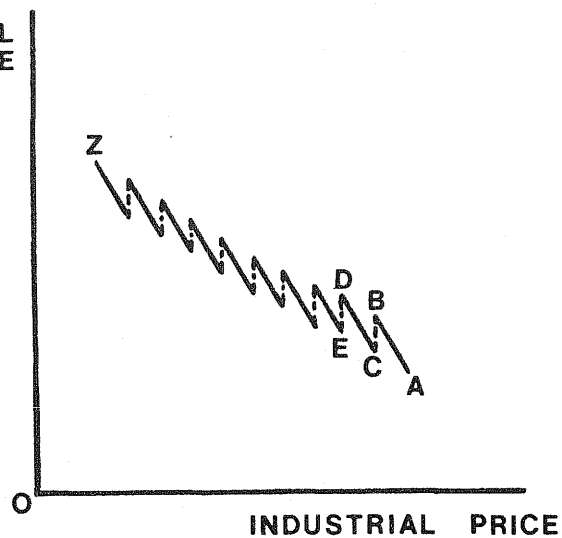


Fig. 6-4 Price pattern in two sectors resulting from a discontinuous demand curve

industrial price is reduced in figure 6-3 below point B, there is a sudden, discontinuous additional industrial load as a major customer connects to the system. This fortuitous event gives rise to a sudden, discrete load increment over which fixed costs may be spread. It is clearly possible to transfer some fixed costs from residential to industrial users and simultaneously keep the industrial price the same since there is a larger industrial load to share any fixed cost burden. Such a reallocation will reduce residential prices in a sudden, discontinuous way. This is shown in figure 6-4 as the downward jump between points B and C. Further reduction in the industrial price brings forth new load along the conventional demand curve segment from C to D in figure 6-3; and in figure 6-4, the corresponding increase in residential prices is shown as the increment between C and D.

Hence, the relationship between residential and industrial prices has a downward sloping, sawtooth nature. In figure 6-4, the overall slope from Z to A has been drawn as negative. That is, very large

reductions in industrial prices cause residential prices to eventually increase. This will be true unless the overall demand curve in figure 6-3 is extremely elastic (almost horizontal) from point A to Z.

Another extreme version of a demand curve is shown in figure 6-5. In this example, demand is well-behaved as price decreases from points B to Z. In this range, industrial price reductions brought about by fixed cost reallocations result in residential price increases as shown in figure 6-6 as the movement from point B to Z.

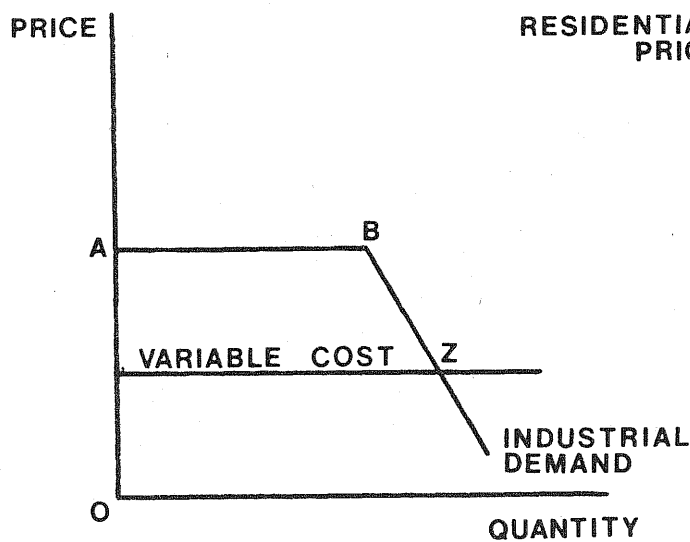


Fig. 6-5 A kinked demand curve

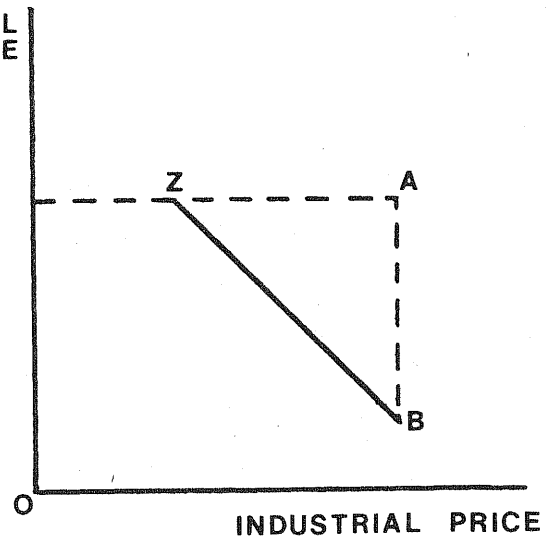


Fig. 6-6 Price pattern in two sectors resulting from a kinked demand curve

results in massive fuel switching and a complete loss of industrial load. The industrial sector would be at point A with zero sales. The residential sector then would have to pay all fixed costs (assuming

regulators deem all capacity to be used and useful). This clearly results in exactly the same residential price that would emerge from a policy of charging industrial customers only variable costs because under both policies nonindustrial users pay all fixed costs. Hence, in figure 6-6, point A, representing a total loss of industrial load yields the same price as point Z, variable cost pricing for industrial customers. If the demand curve in figure 6-5 reflects reality, regulators would clearly prefer an industrial price slightly less than point B since this results in the lowest possible residential price, and a somewhat lower industrial price.

A convenient way to describe discontinuous demand curves, such as the one in figure 6-5, is to call the portion from Z to B stable and the portion from B to A unstable. Small price changes in stable regions of the demand curve result in small changes in the quantity sold. In stable regions, cost reallocation reduces the price in one sector at the expense of the other sector that then bears a larger fixed cost burden. In unstable regions, small price increases result in large, perhaps catastrophic, load losses. In such regions, it is possible that small reductions in industrial price can restore stability, reconnect a large load to the system, and thereby also reduce residential prices.

To summarize, under normal, stable demand conditions, the lowering of industrial prices (by fixed cost reallocation) will raise nonindustrial prices. It is not normally possible to lower the prices in both sectors simultaneously. The NRRI gas distributor equilibrium model has incorporated such stable demand curves. Consequently, our results reflect the usual circumstance encountered in economic matters that there is a trade-off, in this case between two end-user prices, and therefore a substantive choice to be made. Stated alternatively, with stable demand curves, there is no free lunch. When demand is unstable, however, lunch is indeed freely available because both

industrial and nonindustrial prices can be reduced simultaneously by avoiding catastrophic industrial load loss.

The fundamental public policy question, then, revolves around the issue of whether industrial demand is stable (thereby having a conventional price elasticity of perhaps -1.5 to -3.0) or whether it is unstable (having a very high price elasticity of perhaps -10 or even larger in absolute value). Aggregate demand curves for most utilities are very likely to be stable. The demand elasticities estimated by the DOE and presented in this chapter indicate that demand is, in fact, stable. Consequently, the NRRI equilibrium model dealt only with stable demand curves. Unstable demand is a very elusive phenomenon. Such demand, by its very nature, is never observed except at the time when the industrial load suddenly disappears. Predicting the exact price at which such a catastrophe occurs is difficult since historical observation of stable markets offers no clues. The possibility of catastrophic industrial load loss is important, however, and it is the principal reason why several commissions have adopted an entirely new tariff form called flexible rates, a topic discussed along with other state commission policy options in the next chapter.

CHAPTER 7

STATE COMMISSION POLICY OPTIONS

State regulators are necessarily concerned about what policy options are open to them for dealing with natural gas wellhead price deregulation and its possible consequences. The range of options depends in part on each regulator's view of his or her own role in shaping utility energy policy. Commissioners who strictly construe the limitations of their authority as set out in state law may consider only those policy options relating to commission regulatory actions. Others, who see their roles as participants in shaping state or national energy policy, may wish to consider a larger set of policy options that can be taken up with state or federal legislators. Some commissioners may choose to take a more active role in informing the public about the current natural gas situation, about the likely price changes over the next several years, and about the actions that gas customers themselves can undertake to alleviate the effects of rising gas prices.

Accordingly, this chapter contains a discussion of various natural gas public policy options. The purpose is to inform state commissions about a variety of possible national as well as state policy issues. This information may be helpful to commissioners who want to formulate a commission policy or who decide to testify before other governmental bodies, and in addition it may assist commissioners in explaining overall governmental policy to natural gas customers.

State Regulatory Actions

As public utility commissions are faced with ever increasing wholesale rates for gas and the inevitable, resulting increase in retail rates, the commissions encounter great demands for regulatory actions to control prices. The difficulty, of course, is that most of

the costs that enter into retail rates are incurred before the gas reaches state regulatory jurisdiction. Yet, the demands for PUC action remain.

Outside of acting to influence federal or state policymakers, state commissioners have a limited set of policy options available to them. No option is a complete remedy for the problem of nationally rising wellhead prices. The available commission actions are to (a) change rate structures, (b) alter cost allocations among customer classes, (c) create new tariff forms, such as flexible pricing, (d) provide incentives for distribution utilities to seek remedies, and (e) if all else fails, examine the utility's franchise.

Change Rate Structures

As gas rates began rising sharply in the mid-1970s, public utility commissions looked to rate structure changes as a partial solution to the problem of rising prices. The mid-1970s, however, was a period of gas curtailments, and the rate structure reforms were those appropriate during a shortage. Declining block rates were flattened or completely eliminated to discourage excessive, economically unjustified use of gas. Inverted rates, in which the price increases with increasing monthly consumption, were tried in some states in order to penalize large users and reward conservation efforts.

Because rising gas prices created a burden for residential ratepayers, some commissions instituted some form of lifeline rate to provide a subsidy for essential gas use by all, or sometimes just by poor, residential customers. Some tariffs combined a lifeline rate with an inverted rate so that large users--be they residential, commercial, or industrial--would subsidize basic residential gas needs.

In recent years, the arguments in favor of income subsidies have grown stronger as the arguments against conservation rates grew weaker. Some commissions are looking anew at some form of rate subsidy for the poor who cannot handle rising winter heating bills. While most commissioners agree that it is preferable for the federal or state government to provide such relief using tax revenue, in its absence a lifeline rate may be the only policy option affecting the poor available to a commission.

But, determining who should support the subsidy is more difficult than ever. The residential customer with a large family in an old, drafty home will be worse off than before if large-use residential customers provide the subsidy. And, charging it to industrial customers will exacerbate the problem of losing such customers to fuel oil.

Some analysts have suggested that it may be appropriate to reinstitute declining block rates, at least for industrial customers, to keep them on the utility system. Then they could contribute some share of the distribution system costs in the early rate blocks and pay a rate close to city-gate prices in the tail block.

Alter Cost Allocations

In the absence of incremental pricing, each customer class of a gas distribution company typically pays, in the aggregate, a certain class revenue made up of (i) reimbursement for the commodity cost of gas, plus (ii) a share of the distribution company's remaining cost of service. In the rate hearing process, each class's share of the total company cost of service is decided by an allocation procedure. Some leeway is open to the commission in deciding among various cost allocation procedures, thereby affecting rates for each customer class.

Faced with rising wholesale prices, a commission might choose an allocation method that buffers a particular class from effects of rising retail prices. In the past, some commissions were accused of protecting residential customers in this way. Now, commissions are looking for ways to ease the rate increases for large industrial customers with alternate fuel capability because high rates can drive such customers off the utility system, leaving fewer customers to share in supporting the fixed costs of the distribution company.

A commission's ability to shield industrial customers from rising city-gate prices with traditional cost allocation procedures is limited, as one can see from the data presented in chapter 6. Table 6-24 shows, for a 1985 city-gate price that represents a 100 percent increase over the 1980 city-gate price, how industrial retail rates in various regions differ using two demand cost allocation methods. These are the peak responsibility method and the average-and-excess demand method. The rate differences vary from 1 cent per mcf (0.2 percent of the retail industrial rate) for the example utilities in the Central and Southwest regions to 23 cents per mcf (3 percent) for the example utility in New England. Hence, the leeway expected to be available to commissions in 1985 for varying industrial gas rates using traditional cost allocation procedures is small. Typically, prices can be varied by a few cents per thousand cubic feet, which is about 1 percent of the retail price.

Commissions can, of course, have greater impact if they are not constrained by traditional cost allocation procedures. Setting aside for the moment the appropriateness of such a policy, it is instructive to consider the effects of relieving industrial customers of some or all of the costs of supporting the local distribution system. Tables 6-25 and 6-26 show these effects regionally for 1985 natural gas prices and sales. Table 6-25 shows the effects of shifting all distribution company costs from industrial to other customers; that

is, the industrial retail price equals the city-gate price plus a gross receipts tax. This rate relief has minimal effect for the example utility in the Central region: the industrial rate declines only 2 percent, and industrial load increases by 4 percent. But, for other utilities the results are dramatic. For the Middle Atlantic utility, the industrial rate decreases 35 percent, and industrial demand increases by more than 150 percent. A pick-up in industrial demand between 15 percent and 55 percent is expected for most utilities.

If one motivation for keeping industrial customers on the distribution system, however, is for them to bear a portion of system costs, such a policy, of 100 percent cost reallocation, defeats its own purposes. More appropriate would be to have these customers pick up some share of distribution system costs. Table 6-26 shows the effects of industrial customers picking up 50 percent of this normal share of distribution costs. The results are still significant: an increase in industrial load varying from 2 to 73 percent, with typical utilities experiencing from 7 to 28 percent.

While the results may be dramatic, developing a rationale for such a cost allocation is another matter. Under most states' laws, rates must be based on costs, and traditional cost allocation methods have the weight of precedent, if not the force of law. Furthermore, a cost reallocation, such as the 50 percent reallocation in our example, may be appropriate only for a brief time. If the reallocation is designed to allow the gas utility to compete with fuel oil for industrial customers, fluctuations in the price of oil may result in the industrial gas rate being too high or too low. If the price of fuel oil declines after the tariff is set, the reduced gas rate may be ineffective for allowing competition (though perhaps better than no reduction at all); if the price of fuel oil rises, industrial customers may receive an unnecessary rate subsidy. Hence, developing

a rationale for an industrial rate subsidy--one that is valid for the entire future period that the tariff will be in effect--is difficult.

A rationale sometimes offered for transferring costs from large customers with alternate fuel capability to residential and commercial customers is that these latter customers are better off under this policy. That is, it is said to be better for residential customers to have the large industries pick up at least some of the distribution system fixed costs rather than none. The results of our simulation of such cost transfer, described in chapter 6, indicate that this is not so. In every case examined in that chapter, residential and commercial prices increased as these sectors paid a higher share of the distribution fixed costs.

It is important to note that the model used in arriving at this conclusion includes the phenomenon that load loss occurs as prices rise and vice versa. That is, the price elasticity of demand has been accounted for. So, as fixed costs are shifted away from industrial users to the nonindustrial sectors, the industrial price declines which in turn encourages industrial demand, and with more industrial load there are more total sales over which fixed costs can be spread. Some observers believe that by spreading fixed costs over these additional sales, residential and commercial rates can also be decreased, despite the fact that such users are paying a larger fraction of the fixed costs due to the initial cost reallocation. Our results show the opposite--residential and commercial rates increase as they are asked to bear a larger fixed cost burden. Hence, if our simulations are good representations of reality, state commissions can not justify such cost reallocation on the basis of protecting residential customers.

This conclusion should be understood in light of two important conditions, however. First, our conclusion that residential customers

are worse off if they pay part of the industrial sector's fixed cost allocation is based upon the reallocation policy being permanent. Short term cost reallocation may benefit residential users if such temporary action avoids the permanent loss of industrial load, as would occur, for instance, if a major factory moved to another state. Second, our results are based on demand curves that were smooth so that as the industrial price increases, industrial load is lost in a continuous, smooth fashion, as discussed at the end of chapter 6. To summarize that discussion, under normal conditions of smooth demand loss, the lowering of industrial prices (by fixed cost reallocation) raises nonindustrial prices. It is not then possible simultaneously to lower prices in both sectors merely by cost reallocation. If demand is lost in very large increments, however, it is possible to prevent an increase in nonindustrial prices by lowering industrial price and thereby preventing a catastrophic industrial load loss. The possibility of such large scale loss of gas sales and the difficulty of knowing in advance the exact price at which such a loss will occur is the principal reason why several commissions have adopted an entirely new tariff form called flexible rates.

Use Flexible Rates for Large Volume Industrial Customers

Use of flexible rates is one option that several state public utility commissions have considered. Under this procedure, the commission allows a gas distribution company to charge special, lower rates to its large industrial customers so that those customers will continue to use gas instead of switching to an alternate fuel, such as oil. Also, a large, feedstock customer may be allowed lower rates to avoid plant closings when gas prices are too high.

Several states have instituted some form of flexible pricing. These rates have been applied mainly to interruptible customers. The term used to describe the tariff varies from state to state. Usually, the terms, "flexible rate," "floating rate," and "negotiated rate" have been used.

With flexible pricing, floor and ceiling prices are chosen to allow the utility to set prices competitively, within certain bounds. A minimum price, or floor, is set for the retail sale of natural gas. This floor always covers at least the commodity cost of the gas. There is usually a ceiling price also. For example, Pennsylvania sets a ceiling price equal to the rate established for the utility's firm industrial customers. The intent is that the retail price of gas be allowed to vary between the floor and ceiling prices so as to match the cost of the competing alternative fuel.

Flexible rates can be designed to cover the commodity costs of the gas, but only a portion of the utility's other operating and fixed costs. The fraction of these other costs that is covered is adjusted up or down according to the utility's ability to trade off successfully a higher rate with less market share and a lower rate with greater market share. In effect, the utility's ability to prevent fuel switching is a major factor in determining its profitability.

So long as a flexible pricing policy results in a variation of utility profit margin, it is not subject to the criticism raised against industrial cost reallocation generally, namely, that it raises rates for other customers more than the lack of such a policy would. However, if the lowering of flexible prices results in an automatic increase in other customers' rates, then it is likely that other customers would be better off without a permanent policy of flexible pricing. However, a temporary policy of flexible pricing--even if it results in automatic rate increases for other customers--might be in their interest if it avoided a permanent loss of a major industrial load.

Flexible pricing might be considered discriminatory, singling out a particular class of customers for special, preferential treatment. Yet, unduly discriminatory rates are prohibited by state law.

Statutory prohibitions do not seem to have been a factor in those states that have adopted some sort of flexible pricing, but it is not clear whether such prohibitions would prevent the adoption of flexible pricing in other states.

Even if flexible pricing were not prohibited, state public utility commissioners might feel considerable pressure against granting relief to just one class of customers at a time when rates for all gas customers are increasing. Residential customers (and their representatives in state legislatures) might find such a policy rather hard to accept. Any commission approving a flexible rate structure for large industrial customers might find it necessary to justify its action by attempting to educate the public on why it has done so.

With this background, it is useful to examine the flexible pricing rates adopted by various states. At least nine state public utilities commissions have approved or are close to approving some form of flexible pricing tariff. One state, North Carolina, has approved a state-wide system allowing all natural gas utilities that serve the state to institute flexible pricing under certain guidelines.

The design of all the flexible rates is similar. The customers that are eligible for flexible rates are usually large, interruptible commercial and industrial gas users or boiler fuel users of gas. These customers differ from utility to utility; for example, to qualify as a large industrial customer under flexible rates for the Public Service Electric and Gas Company (a New Jersey utility), a customer must consume more than 5000 therms (about 500 mcf) of gas per day. Under the flexible rates of the Elizabethtown Gas Company (another New Jersey utility), a customer need consume only 1700 therms per day to be considered a large user.

Eligibility requirements for the Southern California Gas Company and the Orange and Rockland Utilities of New York differ slightly from those of other utilities. Only electric utilities served by Southern California Gas may receive flexible rates, while Orange and Rockland provides flexible gas rates to its own electric department as well as to large interruptible customers.

Without doing a full 50-state survey, the NRRI has attempted to identify all flexible pricing tariffs approved by state commissions. A state-by-state summary of the floor and ceiling prices in the tariffs identified is contained in table 7-1. Most of these flexible tariffs specify floor and ceiling prices for gas or formulas for calculating them. The actual rate that is charged to a customer eligible for flexible rates falls between the floor and ceiling prices and is usually determined either by negotiation between the customer and the utility or through a formula developed by the utility that prices the gas competitively with known prices for alternate fuels.

Following the approval of a flexible rate design, the traditional role of the state public utilities commission changes very little. Most commissions include in the rate design some type of requirement for their notification and approval of a change in the rate prior to its initiation. In most flexible rate designs, the role of the utility involves the notification of public utilities commissions and customers of changes in gas prices and the notification of customers about interruption of service. States differ only in the amount of prior notice a utility must give and by what means it must give it (e.g., by registered letter or by telephone). The Tennessee Public Service Commission approved flexible rates only through December 1983, at which time it will review the results of this rate design and decide whether to make it permanent. A few utilities, New York State Electric and Gas and Rochester Gas and Electric, for example, specify in the rate designs how excess revenues are to be treated. Fifty

TABLE 7-1

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
<u>California</u>		
Southern California Gas Company's Floating Rate (Decision 83-05-056) May 18, 1983	\$.419 per therm (the current wholesale commodity rate schedule)	\$.567 per therm (the current price to electric utilities served by Southern California Gas that are eligible for the floating rate)
<u>Connecticut</u>		
Connecticut Light and Power Company's Large Volume Firm and Interruptible Gas Service Rates (Docket No. 82-07-01) December 22, 1982	The commodity cost of gas + \$0.39 per mcf to ensure the recovery of the company's costs and its allowed rate of return	95% of the firm gas rates to large general service customers + purchased gas adjustments
Connecticut Natural Gas Corporation's Automatic Interruptible Service and Manual Interruptible Service Rates ¹ September 15, 1982	For Automatic Interruptible Service: \$.4265 per ccf + purchased gas adjustments	For Automatic Interruptible Service: the average posted price of No. 2 fuel oil for the Hartford, Connecticut area
	For Manual Interruptible Service: \$.3607 per ccf + purchased gas adjustments	For Manual Interruptible Service: the average posted price of no. 6 fuel oil for Hartford, Connecticut area
Southern Connecticut Gas Company's Interruptible Gas Service ² (Docket No. 82-06-12)	\$4.15 per mcf + purchased gas adjustments	The lowest price per mcf as approved for firm commercial and industrial general service customers + purchased gas adjustments

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
<u>Delaware</u>		
Chesapeake Utilities Corporation's Flexible Rates (PSC Docket No. 82-10) September 28, 1982	The commodity cost of gas per ccf + a 5% surcharge applicable to these rates + 0.15% of the commodity cost of gas per ccf	For Interruptible Grain Dryer Customers: \$.479 per ccf + any change in the commodity cost of gas from \$3.4904 per dekatherm For Interruptible Commercial and Industrial Customers: \$.482 per ccf + any change in the commodity cost of gas from \$3.4904 per dekatherm
<u>New Jersey</u>		
Elizabethtown Gas Company's Interruptible Service Rates ³ (Docket No. 8112-1039) May 21, 1982	95% of the lesser of the posted consumer tank car prices in New York Harbor for Exxon or Amerada Hess Corporation for the grade of fuel oil that the utility certifies it can use as an alternate fuel	\$.5337 per therm + purchased gas adjustments
New Jersey Natural Gas Company's Load Management Interruptible ⁴ (LMI) Rates (Docket No. 831-46) Pending Decision	The weighted average commodity cost of gas received from the company's suppliers + an allowance for system losses + an allowance for taxes related to revenue from the sale of gas + \$0.02 per therm	The current rates applicable to interruptible service customers + purchased gas adjustments

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
Public Service Electric and Gas Company's Interruptible Service and Off-Peak ISG/OPG Rates ⁵ (Docket No. 833-198) Pending Decision	The average commodity cost of gas received from the company's suppliers + an allowance for an estimated 1% in system losses + a contribution of up to 4 cents per therm + an allowance for taxes related to revenue from the sale of this gas	95% of the applicable rate per therm for the tail block of the company's rate schedule applicable to large volume users + adjustments for raw materials
South Jersey Gas Company's Load Management Service-Large Volume (LMS-LV) Rates ⁶ Pending Decision	90% of the numerical average of posted consumer tank car prices at Paulsboro, N.J. for Exxon and Amerada Hess Corporation's no. 6 fuel oil For boiler fuels: the alternate fuel price ceiling for New Jersey established by the FERC	110% of the numerical average of posted consumer tank car prices at Paulsboro, N.J. for Exxon and Amerada Hess Corporation's no. 6 fuel oil; however, this rate is not to exceed \$.54 per therm + adjustments for raw materials
<u>New York</u>		
National Fuel Gas Distribution Corporation's Flexible Rates ⁷ (Case 28447) March 11, 1983	The commodity cost of gas per ccf + \$.01 per ccf	\$2894.16 per month minimum charge + \$.055306 per 100 cu. ft. x usage over 500,000 cu. ft. up to 3,000,000 cu. ft. or the customer's consumption for the corresponding month of the preceding year, whichever is greater

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
Niagara Mohawk Power Company's Flexible Incentive Gas Rates ⁸ October 1, 1982	The average commodity and winter requirement cost of gas adjusted to convert the purchase price to a sales price + 0.9625 (a factor used to recover gross revenue taxes) + \$.10 to \$.20 per dekatherm	The rate established in the schedule under which the customer would otherwise be served
New York State Electric and Gas Corporation's Flexible Rates (Case 28169) January 11, 1983	The base cost of gas in each rate area + \$0.01 per therm	Not stated in decision
Orange and Rockland Utilities, Incorporated's Flexible Rates (Case 27554) March 27, 1980	The commodity cost of gas	The lowest rates, including the Gas Adjustment Clause (GAC), charged to any firm customer. (The GAC allows for all net benefits from sales to interruptible customers to be flowed through to firm customers during the year following the sale.)
Rochester Gas and Electric Corporation's Flexible, Competitive Rates (Case 27608) July 12, 1982	\$0.30 per therm	The price per therm in the second to last block of the company's rate structure
<u>North Carolina</u>		
Statewide System of Negotiated Rates ⁹	The commodity cost of gas + gross receipts tax + margin	The utility's ordinary rate schedule to the customer classes eligible for negotiated rates (the published tariff)

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
<u>Pennsylvania</u>		
Equitable Gas Company's Flexible Large Volume Service (Interruptible) Rates ¹⁰ August 14, 1982	The average commodity cost of gas received from the company's suppliers + a gross receipts tax	The rate established in the schedule under which the customer would otherwise be served
Pennsylvania Gas and Water Company's Experimental Alternate Fuel Rates ¹¹ April 10, 1983	The greater of: (1) the average commodity cost of gas from the company's suppliers + an allowance for system losses + a gross receipts tax (2) the equivalent rate for alternate fuel available to the customer including transportation costs and other handling charges	The rate established in the schedule under which the customer would otherwise be served
Philadelphia Electric Company's Interruptible Service Rates ¹² September 1, 1982	The highest commodity cost of gas received from the company's supplier adjusted to allow for gross receipts taxes	The 100% load factor price of Rate Schedule L - Large Volume Customers + an allowance for state taxes + purchased gas adjustments
UGI Corporation's Interim Rate FS Experimental Flexible Service Rates ¹³ June 27, 1983	The commodity cost of gas + an allowance for gross receipts tax + a customer cost of \$0.03 per mcf	The rate established in the schedule under which the customer would otherwise be served
<u>Tennessee</u>		
Chattanooga Gas Company's Negotiated Rates ¹⁴ December 13, 1982	None stated in tariff sheet. Implied to be the lowest price at which the company is willing to sell the gas	The rate established in the schedule under which the customer would otherwise be served

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

State and Utility	Floor Price	Ceiling Price
Nashville Gas Company's Negotiated Rates ¹⁵ (Docket No. U-83-7223) March 18, 1983	The commodity cost of gas + an allowance for system losses + an allowance for sales taxes	The rate established in the schedule under which the customer would otherwise be served
United Cities Gas Company's Negotiated Rates ¹⁶ (Docket No. U-82-7211) February 8, 1983	None stated in tariff sheet. Implied to be the lowest price at which the company is willing to sell the gas	The rate established in the schedule under which the customer would otherwise be served
<u>Virginia</u>		
Washington Gas Light Company's Flexible Interruptible Rates ¹⁷ (Case No. PUE830008) Pending Decision	The higher of the commod- ity charge for gas from the company's suppliers + an allowance for system losses + an allowance for gross receipts taxes	The company's firm commodity charge including purchased gas adjustments

Source: With the exceptions noted, the information is taken directly from the commissions' decisions and orders.

¹Connecticut Natural Gas Corporation, Rate Schedule for Rate TS Automatic Interruptible Service, 3 September 1982.

²Southern Connecticut Gas Company, Final Agreement for Interruptible Gas Service - Rates 9-A,B,C,D.

³Elizabethtown Gas Company, Tariff Sheet for Service Classification No. 8 - Interruptible Service, 21 May 1982, Original Sheet Nos. 21, 22.

⁴New Jersey Natural Gas Company, Tariff Sheet for Service Classification No. 4 - Load Management Interruptible Service, 21 January 1983, First Revised Sheet Nos. 30, 31.

TABLE 7-1 (continued)

FLOOR AND CEILING PRICES FOR STATE FLEXIBLE PRICING TARIFFS,
JUNE 1983

⁵Public Service Electric and Gas Company, Tariff Sheet for Service Classification No. 8 - Multiple Parity Service, First Revised Sheet Nos. 31, 32.

⁶South Jersey Gas Company, Tariff Sheet for Service Classification No. 3 - Load Management Service - Large Volume, 12 October 1982, Original Sheet Nos. 8, 15.

⁷National Fuel Gas Corporation, Tariff Sheet for Service Classification No. 7 - Large Volume User, 9 February 1983, Fifteenth Revised Leaf No. 67.

⁸Department of Public Service of the State of New York, Tariff Analysis Recommendation on Filing by Niagara Mohawk Power Corporation, 14 September 1982, p. 3.

⁹Ray Nery, North Carolina Utilities Commission, telephone interview of 16 June 1983.

¹⁰Equitable Gas Company, Tariff Sheet for Rate 5 - Flexible Large Volume Service (Interruptible), 28 May 1982, Second Revised Page No. 39.

¹¹Pennsylvania Gas and Water Company, Tariff Sheet for Service Classification No. 7 - Rate Schedule AF - Experimental Alternate Fuel Rate, 24 March 1983, First Revised Page No. 52.

¹²Philadelphia Electric Company, Tariff Sheet for Interruptible Service Rates, 30 July 1982, Original Page No. 37.

¹³UGI Corporation, Tariff Sheet for Interim Rate FS Experimental Flexible Service Rates, 7 January 1983, Second Revised Page No. 61.

¹⁴Chattanooga Gas Company, Tariff Sheet for Service Classification No. 1 - Rate Schedule 55-1 Special Services, 8 December 1982, Original Sheet Nos. 37, 38.

¹⁵"The March of Events," Public Utilities Fortnightly, April 28, 1983, p. 67.

¹⁶United Cities Gas Company, Tariff Sheet for Negotiated Gas Service, 21 December 1982, Original Sheet No. 7.2.

¹⁷Jerrold R. Perkins, Testimony before the State Corporate Commission of Virginia, Exhibit WGL-C, p. 3.

percent of New York State Electric and Gas revenues collected in excess of the floor price are flowed through as rate reductions to firm customers, and the remaining 50 percent is applied to accelerate depreciation on the gas plant. In the case of Rochester Gas and Electric, 20 percent of any additional revenue over the floor price is retained by the utility as an incentive to price competitively, and 80 percent is passed along to ratepayers through reductions in the purchased gas adjustment rate. The California Public Utilities Commission approved flexible rates for the Southern California Gas Company in early 1983 and decided in May 1983 to allow the company to increase the rates of other customers to recover the undercollection resulting from flexible prices.

Provide Incentives for Distribution
Utilities to Seek Remedies

Another policy option for the state commission is to provide an incentive for its distribution utilities to seek reforms in their relationships with suppliers. Alternatively, the commission may take a hard line with its utilities in order that the utilities take a hard line with their suppliers.

In this view, regulation acts as a substitute for competition. In a competitive market, companies that fail to control costs, whether their own or their suppliers' costs, have their profit margins squeezed. Those who control costs find profits to be adequate or better. Some analysts argue that in the current natural gas market there is no adequate mechanism for signals to flow backward through the system--from consumer to distributor to pipeline to producer--that prices are too high, even so high that a large number of customers may leave the system. Perhaps then, regulators need to initiate such a signal with the distributor, through reward, penalty, or simply "jaw-boning," to take aggressive action for dealing with any over-priced supplies.

Examine the Franchise

Perhaps the most difficult question a commission could face is what to do if a utility should lose most of its industrial load. The question is particularly difficult if that load accounts for a large fraction of the system's capacity.

It is often suggested that as a system loses some load the commission has the obligation to spread the costs of unused capacity over the remaining customers. For relatively small amounts of excess plant or for a temporary, large loss of load, such a solution may have merit, at least for its expediency. But, in a system with an initially large industrial load and small nonindustrial load, loss of industrial load may strain the ability of remaining customers to absorb the extra cost. In either case, a rationale for asking remaining customers to be responsible for the costs of unused capacity is lacking.

The argument that the company must be kept financially sound so that service can continue to remaining customers is, at least in theory, not sound. The investment community assumes the risk associated with the company. Stockholders, who expect to benefit when sales volumes expand, should be prepared for losses when their company's share of the energy market decreases.

If the loss of industrial load were severe enough, losses could affect bondholders as well as stockholders, raising the spectre of default and bankruptcy. As a last resort, a commission might have to be prepared to preside over such an event, when a major concern would be the continuity of service to remaining customers. The commission would presumably cooperate with the courts so that the corporate person purchasing the system would receive the franchise to serve the jurisdiction. The purchaser, perhaps a neighboring utility interested in expanding its territory, would pay a fair market value for the

usable capacity--a value that would yield a fair return on service to the reduced number of customers, who would be served at a fair price.

Influencing State Policy

While state control of the natural gas market is rather limited, state regulators might find it useful to promote some policy options for dealing with rising natural gas prices that are available to the state legislature and the state energy agency. Five policy options that can be pursued by state regulators in the legislatures and state energy agencies are: encouraging state legislatures and state energy agencies to adopt or expand conservation and weatherization programs; working through the state legislature to institute low-income residential heating subsidies programs; monitoring purchased gas adjustment clauses; and, in producing states only, promoting legislation providing for either "self-help" gas or contract or common carriage arrangements for intrastate gas and instituting price controls on intrastate gas.

Promote Conservation and Weatherization

As natural gas prices continue to increase, a significant state policy action is to encourage conservation and weatherization. In 1979, one year after the enactment of the National Energy Act of 1978, a thorough, 50-state survey documented that more than half of the states had initiated energy assistance programs to ease the energy cost burden on the poor, the elderly, and the disabled.¹⁸ Many of

¹⁸College of Urban Affairs, Energy Assistance Programs and Pricing Policies in the 50 States to Benefit Elderly, Disabled or Low-Income Households (Cleveland: Cleveland State University, 1979) as cited in David Sweet, "National Energy Policy and Poor and Elderly Utility Consumers," in Energy and Communications in Transition: The Proceedings of the Institute of Public Utilities' Eleventh Annual Conference, ed. Harry M. Trebing (East Lansing: Michigan State University, 1980), pp. 8-25.

the weatherization and conservation programs covered by the survey included the use of state funds to supplement the federal conservation and weatherization programs administered by state agencies, often by the state energy office. Other weatherization and conservation programs were state tax incentives for weatherization, utility-sponsored load programs for weatherization, utility-sponsored and state-sponsored energy audits, and educational and marketing efforts regarding conservation and weatherization by state agencies.

One option that state regulators might wish to support is state legislation that goes beyond federal law in requiring gas utilities to provide weatherization and conservation services to residential customers, to provide financial assistance for these services, and to stimulate the use of available conservation and weatherstripping services by customers. Energy conservation and weatherization services provided by utilities could include listing conservation measures, such as adding weatherstripping, insulation, and storm doors and windows, and listing registered weatherization contractors. Utilities could also provide on-site inspections or energy audits for homes resulting in cost estimates of conservation measures.

Financial assistance could be legislated in several forms.¹⁹ Zero or low interest loans could be used, with the difference between the market rate and the lower rate of interest being made up in tax credits to the lending institutions. Allowing a utility to recover the costs of financing the loans as an ordinary and reasonable expense in the cost of service is an option. Including interest charges in

¹⁹For examples of this type of legislation, see The National Regulatory Research Institute, Utility Regulation and Legislative Process in Oregon (Columbus, Ohio: The National Regulatory Research Institute, 1979).

the rate base and passing these costs through to ratepayers is also an option.²⁰

Idaho, for example, has instituted a direct grant program, replacing a former zero-interest loan program, for financing weatherization measures. The former loan program, in times of high interest and low home turnover rates became costly to the ratepayer. The direct grant program, which will pay 70 percent of the estimated cost of a measure while requiring 30 percent of the cost to be paid by the homeowner, is expected to encourage competitive bidding, discourage "goldplating", and create a much higher benefit-cost ratio.²¹

Personal income tax credits could be used to encourage residential customers to use conservation measures, perhaps including the use of renewable resources. A mandatory approach is contained in an Oregon statute requiring that new homes meet certain weatherization standards set by the state in order for buyers to receive homeowner loans. While no one method or approach is necessarily best, given the increasing burden of natural gas bills on residential customers, state regulators might find it desirable to reexamine and, perhaps, to promote the expansion of the conservation and weatherization programs in their states.

In addition, state commissions may want to make sure that other state agencies are taking full advantage of available federal

²⁰For a general discussion of the possible regulatory treatments of utility sponsored conservation and weatherization programs, See R.J. Krasniewski and R.J. Murdock, Expense and Investment Treatment of Residential Conservation Measures (Columbus, Ohio: The National Regulatory Research Institute, 1980).

²¹"Zero-interest Loan To Be Replaced with Direct Grant Program," Public Utilities Fortnightly, December 9, 1982, p. 62.

conservation programs for assisting states. These federal programs are described later in this chapter.

Promote Low-Income Heating Subsidies

State regulators may wish to look beyond the normal confines of economic regulation and address the problem posed for the poor by rising energy costs. One way of treating this problem would be to promote the enactment of state legislation providing for direct heating subsidies for targeted groups. Another would be to promote the establishment of fuel fund programs by the utilities and charitable organizations.

State regulators might choose to encourage the legislature to establish or increase heating subsidies for the poor. Many heating subsidies have been enacted by state legislatures to alleviate the burden of rising energy costs on the poor. One example of a direct heating subsidy is the Ohio Energy Credits Program, which provides substantial discounts on the winter heating bills of elderly or disabled utility customers with low incomes through a one-time cash payment to those retail fuel dealer customers and which provides a tax credit for a utility's state excise tax to any utility participating in the program.²² Another example of direct heating subsidies is a Michigan program that provides maximum benefits of \$200 for poor or elderly homeowners and \$160 for renters. Wyoming has a heating subsidy program based on state tax refunds, instead of direct subsidy payments, for the eligible elderly or disabled residents.²³

²²K.A. Kelly, et al., Alternatives to the Ohio Energy Credits Program (Columbus, Ohio: The National Regulatory Research Institute, 1979).

²³These three heating subsidy programs are described in Sweet, op. cit., p. 20.

Regulators may also encourage gas utilities to set up a heating subsidy program, perhaps by encouraging the legislature to create tax incentives for utility participation. Innovative approaches for providing direct heating subsidies to the poor have been adopted by several utilities, however, without tax incentives. One such program, instituted by the Pacific Gas and Electric Company (PG&E), is the REACH fuel fund program, which makes \$5 million available for financial assistance to low-income customers.²⁴ PG&E began the program by donating \$1 million in seed money and \$2 million to be matched by charitable contributions to the REACH fuel fund. The fuel fund is administered through the Salvation Army. A low-income customer can use the funds to pay for his home's primary heating source, whatever it may be. Two utilities in Idaho, the Idaho Power Company and the Pacific Power and Light Company, have also entered into agreements to aid low-income customers through fuel fund programs administered by the Salvation Army. The Idaho Power Company's fuel fund program allows a low-income family to receive up to \$100 in energy assistance. In January 1983, more than 6 percent of Idaho Power's customers have provided a \$16,000 charitable contribution to the fund by taking advantage of an option to overpay their bills in order to donate to the fuel fund.

In Minnesota, Minnegasco instituted a similar program of voluntary, tax-deductible contributions, known as HeatShare. By November of 1982, Minnegasco had collected one-half million dollars from customers, stockholders, and its primary pipeline for distribution to the elderly and handicapped poor by the Salvation Army for use in paying energy bills.

Regulators may also want to check on whether their states are fully using the federal heating subsidy programs available, as described later in this chapter.

²⁴See the Public Utilities Fortnightly, March 3, 1983, pp. 48-50.

Challenge Purchase Gas Adjustment Clauses

At least two state legislatures have considered bills that might modify the effect of NGPA guaranteed contract price pass-through. These bills, one passed by the Ohio House and the other enacted by the West Virginia state legislature, provide that the local distribution company is not guaranteed the recovery of the cost of purchased gas. The Ohio bill would provide a cost-incentive factor for local distribution companies that buy Ohio-produced gas with a cost that does not exceed the average cost of gas available from outside the state. Thus, Ohio's local distribution companies would be rewarded, if they buy Ohio gas that costs less than the average cost of interstate gas, by being allowed to recover more than the actual cost of the Ohio gas. However, if the distribution companies buy interstate gas, they can only pass through the cost if they can demonstrate to the PUC that the gas purchase price is prudent and reasonable. If the local distribution company cannot demonstrate that the price paid for purchased interstate gas is prudent and reasonable, then the PUC would prohibit the utility from recovering from its customers any portion of the costs above the price of identical quantities of Ohio-produced gas.²⁵

The West Virginia legislature has also enacted legislation placing a one-year moratorium on any gas rate increases. The bill does, however, grant the PSC discretion to allow exemptions from the blanket moratorium for pending cases, purchased gas adjustment cases, and instances of extreme hardship. The bill also provides for procurement policy reform. The bill provides that no West Virginia gas utility will be allowed any rate increases without first demonstrating that it is purchasing the lowest-price supply readily available.²⁶

²⁵David Leland, Ohio Representative, telephone interview of May 1983.

²⁶See "Utility Reform Legislation Enacted in West Virginia," NARUC Bulletin No. 16-1983, April 18, 1983, pp. 24-25.

State regulators in other states might wish to consider whether to promote the enactment of state legislation that would prohibit or somehow modify distribution company purchased gas adjustment clauses. Such legislation might have the positive effect of both cushioning customers from the increasing costs of gas and providing local distribution companies with an incentive to engage in hard bargaining with their interstate pipelines over minimal billing provisions. On the other hand, unless the state legislation was carefully drafted so as to promote and, perhaps, reward the purchase by the local distribution company of the lowest-cost available gas, the enactment of such legislation might unfairly penalize the local distribution company for effects of the agreements reached between pipelines and producers and the guaranteed pass-through under the NGPA.

Institute Common or Contract Carriage and Self-Help Programs

State regulators in producing states might want to consider whether the status of intrastate pipelines should be changed from public utility to common or contract carrier. The state legislature in at least one state, West Virginia, has enacted a statute that provides that intrastate pipelines and any unused portion of interstate pipelines are required to serve as common carriers.²⁷

While there might be some challenge to state legislation changing the status of an intrastate pipeline to that of a common or contract carrier, the transportation of interstate gas by intrastate pipelines has traditionally been subject to state regulation. Nothing in the NGPA changes the status of intrastate pipelines to that of an interstate pipeline under FERC jurisdiction as long as the intrastate pipeline sells intrastate gas, high-cost (section 107(c)(1-4)) natural gas, new (section 102) gas, new onshore production well (section 103)

²⁷See Public Utilities Fortnightly, April 28, 1983, p. 59.

gas, or gas in interstate commerce authorized by the FERC under section 311(b) or 312 of the NGPA.²⁸ Thus, nothing in the NGPA or the NGA would, on its face, prohibit a state legislature from changing the status of its intrastate pipelines from public utilities to common or contract carriers. However, a state legislature changing the status of intrastate pipelines to that of common or contract carriers may, in fact, only be enacting a cosmetic change; the price ceilings of the NGPA would still apply to the first sales of the natural gas from the interstate producer to the intrastate common/contract carrier.²⁹ Nevertheless, in some cases where intrastate wells have been shut-in and there are industrial customers who cannot otherwise obtain gas, state regulators in producing states might find this policy option attractive.

A more direct method of providing a type of relief similar to that described above would be for state regulators to promote the legislative enactment of a self-help program. One example of such a program is the self-help program that was first instituted in Ohio in 1973.³⁰ A self-help program permits a gas customer to use the intrastate pipelines to transport self-help gas to that customer. Self-help gas can be obtained from wells drilled either by or for the customer or by a gas producer. During the gas curtailments of 1976-77, the self-help program was used to allow curtailed industrial customers to gain access to gas. A self-help gas program might now be used to allow shut-in intrastate gas producers to sell their low-cost gas directly to gas customers. Such a program might be

²⁸See Section 601(a) of the Natural Gas Policy Act of 1978.

²⁹See the Natural Gas Policy Act of 1978 section 2(21)(iii). The first sale can mean any volume of sale to any person for use by such person.

³⁰See Audeen Walters, Kevin Kelly, and James Bydolek, Ohio's Emergency Purchase, Transfer, and Self-Help Programs (Columbus, Ohio: The National Regulatory Research Institute, 1977).

particularly helpful to non-exempt industrial customers that are subject to incremental pricing if they can get access to the self-help gas, because the incremental pricing provisions of the NGPA do not extend to gas sold by intrastate pipelines.

Thus, state regulators in gas-producing states might find it in their own self-interest to consider promoting legislation that would either change intrastate pipelines into common or contract carriers or institute a self-help program. However, such legislation would do little or nothing to relieve the problems faced by state regulators in non-gas-producing states.

Institute Price Controls in Producing States

While it now seems unlikely that producing states would institute state gas wellhead price controls, this course of action appears to be allowed by the NGPA. The Congress addressed the issue of state regulation of wellhead prices in section 602(a) of the Natural Gas Policy Act. According to the conference committee report, section 602(a) provides that the NGPA does not affect the authority of any state to establish or enforce a maximum lawful price for sales of gas in intrastate commerce so long as this price does not exceed the applicable NGPA maximum lawful price, if any. Because section 602(a) of the NGPA, according to the conference committee report, is limited to sales of gas in intrastate commerce, institution of price controls for wellhead gas is really only available to state legislatures in gas-producing states and then only for the portion of gas that remains in intrastate commerce.

State regulators in producing states may wish to consider encouraging their state legislatures to pass legislation that would provide the state regulators with the power to establish and enforce a

maximum lawful price for gas in intrastate commerce that is lower than the applicable NGPA ceiling price. By doing so, the state might be able to block the operation of indefinite price escalator clauses in local producers' gas contracts.

Such a strategy, of blocking indefinite price escalator clauses, is the basis of a Kansas law, entitled the Kansas Natural Gas Protection Act. The act places restrictions on the operation of indefinite price escalator clauses in contracts for gas in intrastate commerce. The Kansas law prohibits the parties to a contract for gas in intrastate commerce from considering either federally set ceiling prices or other contract prices paid in Kansas when these parties adjust prices using the price escalator clauses in their contract. The law has withstood a court challenge and was upheld by the U.S. Supreme Court as a legitimate exercise of a state's power.³¹

Influencing Federal Policy

Because federal control of the natural gas market is quite extensive, state commissioners who want to undertake some fundamental reform in government regulation of the gas industry must seek to influence federal policy choices. As discussed in chapter 6 of this report, the wellhead price and interstate transportation fee typically exceed 80 percent of the price of natural gas to final users. Consequently, there is relatively little latitude for state commissions to affect retail customer prices independently. State regulators may wish, however, to present and promote their own viewpoints at the federal level. This section reviews eight issues that are primarily related to federal policy making. These are discussed more or less in order of their importance to state regulators.

³¹See Energy Reserves Group v. Kansas Power and Light Company, 459 U.S., 74 L. Ed 2d 569 (1983).

Alter Wellhead Price Controls

There are numerous bills pending in the Congress that would change the timing and degree of decontrol of wellhead prices of natural gas. These were discussed in chapter 4 of this report. The legislation sponsored by the NARUC is silent on this issue and thereby implicitly supports the current timetable of the NGPA that decontrols most new gas prices on January 1, 1985. Consumer groups tend to support legislation that continues ceiling prices. Producers are divided on this issue depending on whether or not they own old sources. Those with such sources tend to be in favor of total decontrol because of the resulting capital gains on the already discovered gas. Small producers, particularly those that have invested in deep wells, generally favor a continuance of existing gas price controls because this allows the price of such gas to be quite high, as explained in chapter 3 in the context of the rolled-in pricing equilibrium model. This diversity of interest groups has led some political observers to conclude that it is unlikely that any natural gas pricing legislation will be passed in the 98th Congress.³²

Many state public utility commissioners, particularly those in gas consuming states, tend to favor price controls for natural gas. Decontrol of old gas prices is almost universally opposed, and it is not uncommon for state regulators to advocate a continuation of price controls for new gas beyond the current NGPA deadline of 1985. While it is true that people in their role as consumers always benefit from lower prices, the public policy issue of price controls transcends this rather narrow perspective. It is not at all clear that the public interest is served by arbitrarily keeping gas prices low. State PUCs understand this issue implicitly when the topic is setting

³²Comments of Lee White and Alvin Alm at a Natural Gas Futures Market Seminar sponsored by the New York Mercantile Exchange, Washington, D.C., April 18, 1983.

the rate of return on an electric utility's invested capital; the state commission must balance the interests of the consumer and the producer in determining that rate of return. Allowing only a low rate of return would have the desirable effect of lowering the price to consumers; however, such an action is obviously detrimental to investors and might even be construed as confiscation of capital. Similarly, holding gas prices low is not unambiguously "good," even from the viewpoint of consuming states. As is usually the case, the public policy issues can be understood in the context of two important and frequently conflicting ideas--economic efficiency and interpersonal equity.

Whether keeping gas prices low constitutes good public policy cannot be assessed without some estimate of the marginal cost of gas at the wellhead. Forcing the price of old gas below the current marginal cost of new wells unfortunately (but seemingly always) has the practical result of inducing a misallocation of resources. This inefficiency occurs because no one has yet devised a way to prevent economic rents (pure profit) or to tax such rents without also affecting price. For example, even the oil windfall profits tax, despite its name, is in reality an excise tax that affects price. Any government policy that changes price will induce behavioral changes in the market place, which in a competitive context leads to inefficiencies. That is, a frequently heard assertion is that decontrol of old gas will not, in itself, yield any new gas discoveries. Suppose this statement is true. The practical way of preventing the flow of economic rents to gas well owners is the policy of rolled-in pricing. As explained in chapter 3, such a policy does not simply extract rents from producers. It also lowers the average price of gas and encourages demand which is supplied by gas sources that cost more than at least some users are willing to pay. Consequently, the possibly laudable goal of transferring potential profits from producers to consumers is thwarted by our inability to fashion a practical

mechanism to do this in a way that is neutral with respect to price. The economic inefficiency may be minor if supply or demand is relatively unresponsive to price; however, it is not nonexistent, as implied by the argument that decontrol will bring forth no new supplies.

The value of the resource misallocation may be acceptable if the price controls sufficiently improve social equity. Whether it does or not is a subjective matter about which reasonable people can disagree. In forming their opinion, state regulators may choose to consider only the economic well-being of their state residents vis-a-vis the rest of the world. In doing so, however, a complete analysis would consider all income flows into and out of a state that result from price decontrol, and not simply the increased payments for natural gas from consumers to producers. In particular, additional income will accrue to residents in a consuming state due to capital gains of mineral company stocks, dividends, and the distribution of federal tax receipts. Gas and oil company ownership is widely spread and includes pension funds, insurance companies, and so on. In addition, gas consuming states may export more goods to the regions of the country where the net gas income is positive. A recent study at Harvard's Energy and Environmental Policy Center accounted for such inter-regional income flows in an analysis of the Northeast. Under a variety of plausible expectations regarding international oil prices, severance taxes in producing states, and natural gas supply and demand elasticities, the study concluded that "the Northeast region would experience increased aggregate regional income through a policy of natural gas price decontrol."³³ Hence, even the narrow self-interest equity viewpoint of a consuming state may be more favorable toward decontrol if a complete set of income flows is considered. It is

³³J.P. Kalt, H. Lee, and R. Leone, "Natural Gas Decontrol: A Northeast Industrial Perspective," Discussion Paper E-82-09, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts, October 1982.

important to note, however, that the increase in Northeast income in this example may not improve the distribution of income within the region. Low income consumers may not be helped by decontrol even if aggregate income does improve.

The issue of whether natural gas should be totally or partially decontrolled also can be analyzed by considering the efficiency of the resource allocation in comparison to its fairness. The principal argument in favor of at least some price controls over natural gas is that such a policy prevents windfall profits. Such an argument can be quite persuasive in a society that is increasingly concerned with social justice and the distribution of income. Despite the importance of this line of reasoning in the political debate, no one has yet published a study, to our knowledge, that estimates the improvement to income distribution from a policy of partial control. Against any improvement in social justice must be weighed the resource misallocation costs associated with distorting price away from marginal cost. The long-run market distortions, as discussed in chapter 3, include those associated with (1) rolled-in pricing, which presents consumers with a low price and encourages excessive use and which pays individual producers their own marginal cost, encouraging the development of excessively expensive sources, (2) a misordering of supply because of the gas categories established in the NGPA, and (3) a misordering of users due to the Fuel Use Act. The last of these is undoubtedly quite minor. In addition, social justice may be enhanced by preventing windfall profits, but the improvement is nonetheless limited because old, price controlled gas is unevenly distributed among the pipelines. The relative importance of these efficiency and equity arguments must be resolved by lawmakers, as it is from time to time, although such issues continue to arise.

Apart from price decontrol, a separate public policy issue is the speed with which any pricing policy is adopted. Some consumer groups

favor slowing down the decontrol by extending the NGPA beyond 1985.³⁴ Others argue that immediate decontrol would eliminate costly regulations in the gas industry, negate the incentives to reclassify gas from one price category to another and encourage sufficient supply (and discourage enough demand) that there would be no price spike in 1985.³⁵ As before, the issue has both economic and equity ramifications. Equity is promoted by gradualism, in the opinion of many observers. Consumers who have recently purchased capital equipment based upon particular price expectations are naturally disappointed if the price suddenly increases a short time later due to a government policy change. Uncertainty about the consequence of a policy change also provides a reason to change only slowly, so that the policy can be modified later after better determining its outcome. Gradual decontrol, however, may provide a reason for some producers to withhold their supplies in order to fetch a higher price after prices are unrestricted, thus arguing for immediate adoption of the new policy. Also whatever adjustments consumers might make in response to higher gas prices will only be delayed by a policy of gradualism. If it is in the consumer's best interest to insulate his or her own home after some future decontrol date, delaying that activity will only lengthen the period during which the home is inefficiently wasting energy. An immediate policy change is superior on these grounds. Since some of these arguments involve value judgments about fairness, the political process, imperfect as it is, must weigh the arguments on both sides.

Alter Contract Provisions

The second major federal issue regarding natural gas concerns a series of clauses in contracts between major pipelines and their

³⁴See "Deregulation: The \$40 Billion Natural Gas Scramble," CRA Research Review (Boston: Charles River Associates, May 1982).

³⁵See Paul W. MacAvoy, "The Time To Deregulate Gas Is Now," New York Times, 26 September 1982.

suppliers, which many see as the source of several so-called market ordering problems. Such clauses include take-or-pay provisions, indefinite price escalators, most favored nation agreements and market-out arrangements. These clauses and the resulting market-ordering problems are discussed in earlier chapters. There are numerous bills pending before the Congress that address these issues, as discussed in chapter 4. For example, the legislation endorsed by the NARUC Executive Committee deals almost entirely with such contract clauses.

The underlying public policy issue here is whether and to what extent it is appropriate for federal authorities to intervene in contractual arrangements that were freely and legally entered into by both parties. At the time when these contracts were negotiated, these clauses, which seem onerous to the pipelines and their customers now, were considered mutually advantageous. A fundamental issue concerns the nature of federal responsibility, if any, to alleviate hardships that occur on one side of a contract when unfortunate or unforeseen events transpire.

In the case of natural gas, federal regulation has been pervasive for decades, and the typical producer-pipeline contract is at least partly the result of that regulation. The recent high rates of take-or-pay, for example, were explained in chapter 3 as partly a reaction to federal price ceilings since such provisions provide a way of increasing the implicit, real value of contracts to producers when pipelines are restricted by price ceilings. Consequently, federal authorities are partly responsible for the current status of the gas market, and hence some federal remedy may be appropriate. The choice of remedy, however, is not unanimous as indicated by the variety of bills pending before the Congress.

An FERC analyst has suggested that the political quid pro quo for relieving pipelines of their onerous contract provisions might be more rapid or more complete price decontrol.³⁶ Such a package would have some benefits for both producing and consuming states. Altering pipeline-producer contractual arrangements may also be an occasion for reconsidering federal policy on the public utility status that the pipelines now enjoy as opposed to an arrangement involving some responsibility for carrying the natural gas of others for contract. It might be argued, for example, that in exchange for relief from undesirable contract clauses, pipelines be required to devote some small fraction of their capacity to contract carriage. State commissions may wish to suggest to the Congress, as the nation enters a new era of diminishing federal control over natural gas wellhead prices, that consideration also be given to altering fundamentally the industrial structure.

Institute Common or Contract Carriage

Perhaps the most radical industrial reorganization would be for the Congress to require that interstate pipelines be common carriers. As such, a pipeline would be required to carry gas owned by others in exchange for a regulated transportation fee. The pipeline itself would own no gas but would merely move it from place to place. A less drastic measure would be to require some form of mandatory contract carriage whereby some fraction of the gas moving through a pipeline would not be owned by the pipeline but would be transported for some other owner for a transportation fee, which would be federally regulated.

³⁶See Robert Means, "Issues in the Debate over Natural Gas Decontrol," Public Utilities Fortnightly, October 28, 1982, pp. 18-24.

The Illinois Commerce Commission, for one, is in favor of full common carrier status. It calls such a policy the Consumer Access Plan because any customer, most likely a distribution company, could contract directly through gas brokers for his requirements.³⁷ This arrangement would have the important advantage of increasing the number and variety of user-supplier contacts and thus increasing the competitive aspect of this market. The Association for Equal Access to Natural Gas Markets and Supplies favors a contract carrier arrangement initially, with the ultimate objective of converting gas pipelines to common carriers.³⁸ The issue has also been discussed by the Congressional Research Service and the NRRI.³⁹ As previously discussed, several bills pending before the Congress provide that a pipeline must ship gas under a transportation-only contract if the pipeline exercises a market-out provision and the producer can find another buyer.

There are several problems that must be resolved if such a contract carrier system is designed. These include arrangements for emergencies, possibly by giving the FERC certain authority to deal with periods of unusually high demand. Such powers might include allocation of supplies as well as supervision of the daily operation of the pipelines. Assuring adequate revenues may be a problem,

³⁷Illinois Commerce Commission, The Consumer Access Plan: Natural Gas Pipeline Common Carriage (State of Illinois: March 1983).

³⁸See David W. Wilson, "Would a Form of Common Carrier Status for Pipelines Create a More Competitive Market?" presented at the Institute of Public Utilities Fourteenth Annual Conference, Williamsburg, Virginia, 13 December 1982.

³⁹See U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce, Natural Gas Regulation Study, prepared by the Congressional Research Service and The National Regulatory Research Institute, Committee Print 97-GG (Washington, D.C.: 1982).

although long-term shipping contracts may alleviate this. There are also the usual problems of taking advantage of economies of scale, regulatory lag, and the pipeline meeting its own legitimate service requirements.

Another problem with common carriage deserves special mention. This is the transmission and storage capacity issue. The pipeline industry opposes the notion of common carriage, not surprisingly. An important reason for the opposition of such industry groups as the American Gas Association is that a contract between a producer and a distributor, for example, also requires some assurance that pipeline capacity will be available when the buyer wants delivery. This has been interpreted by one industry spokesman to mean that the FERC would need to be involved in the day-to-day operations of the pipeline system.⁴⁰ This view is implicitly based on current pricing practices being continued into the future. The danger being highlighted by the AGA and other industry groups is that pipeline capacity will not be available during the peak winter heating season, and consequently FERC authority will be required to allocate the scarce capacity.

It is true that when the same transportation fee is charged during the summer and winter months the likely result will be excess capacity during the summer and excess demand during the winter. It is not at all obvious, however, that the best solution is to rely on the allocative, nonprice rationing authority of the FERC. Economic efficiency would be promoted and administrative procedures simplified if some form of peak-load, in this case seasonal, pricing of capacity were adopted instead. Indeed, the primary reason for any seasonal variation in gas costs is limited pipeline and storage capacity as opposed to any production limits imposed by the size of the gas

⁴⁰Remarks by Michael German, American Gas Association at the National Gas Futures Market Seminar sponsored by the New York Mercantile Exchange, Washington, D.C., 18 April 1983.

reservoirs. In these circumstances, efficient transportation prices would be higher during the peak heating season. The pricing policy might be set in advance by the FERC in which case there is still some probability that demand would exceed available pipeline capacity at the announced price. Another possibility would be to auction off space on the pipeline up to the capacity limit. Using price to clear the market for capacity in this way raises the possibility that the revenues collected may exceed or fall short of the regulated revenue requirement, however. Which allocative mechanism, FERC or price, is superior is a matter that deserves some careful consideration. The purpose of this discussion is not to advocate one or the other. Rather, it is to point out that an important advantage of contract carriage is that it facilitates the transmission of price signals between distributors and producers. It would be ironic if such a pricing system were rejected based on the absence of a seasonal pricing system for capacity, when these two pricing systems together could substantially eliminate the need for FERC intervention.

Other state commissions may want to examine the Illinois Commerce Commission plan and to support common or contract carriage.

Initiate Antitrust Actions

The natural gas industry, as yet, has not been scrutinized under the antitrust laws. This may be changing, however, since Representative Philip Sharp has recently (March 1983) asked the Department of Justice and the Federal Trade Commission to assist the House Energy and Commerce Subcommittee on Fossil and Synthetic Fuels in identifying practices in the industry that might be subject to the antitrust laws. Lawsuits filed by natural gas customers, distributors, or producers may provide a way to improve the competitive environment in the

industry. State regulatory commissions may choose to support these actions.

There are many examples of provisions in producer-pipeline contracts that may be vulnerable to antitrust liability. Some analysts, for example, have contended that contracts that base the commodity price on prices in other contracts between other parties would be an illegal restraint of trade elsewhere in the economic system. Their conclusion is that three-party most favored nation clauses cannot be permitted to exist in the nonregulated segment of the natural gas industry.⁴¹ Such practices might be challenged under any of three provisions of the antitrust laws: Section 1 of the Sherman Antitrust Act, Section 2 of the Sherman Antitrust Act, and Section 3 of the Clayton Antitrust Act.

Section 1 of the Sherman Act precludes any contracts or combinations that restrain trade unreasonably.⁴² Thus, if a potential plaintiff, such as a non-affiliated distribution company, can show that a contract provision in a producer-pipeline contract has anticompetitive effects that outweigh its procompetitive effects, then the contract can be voided. Several types of producer-pipeline contract provisions might be good candidates to be attacked pursuant to a Sherman Act Section 1 action. These include take-or-pay contract provisions, oil parity contract clauses, third-party most favored nation clauses, and long-term exclusive contract provisions. Taken together, such contract provisions may significantly reduce the competitive nature of the market.

⁴¹Charles G. Stalon, "A Regulator's View of Some Important Defects in the Current Process of Natural Gas Deregulation," paper presented at the NARUC Annual Studies Program, Michigan State University, 8 August 1982.

⁴²Sherman Antitrust Act, 15 USC sec. 15.

Section 2 of the Sherman Act prohibits monopolization, attempts to monopolize, and conspiracies to monopolize.⁴³ While the possession of monopoly power is not in and of itself a violation of antitrust, purposefully acquiring, maintaining, or extending monopoly power is a violation. Thus, if a pipeline were expanding or vertically integrating into a second market level and were to achieve a competitive advantage at that second market level primarily because of its ability to use its existing monopoly power as leverage, this might be a violation of the Sherman Act. In particular, a pipeline might be considered an essential facility if duplication of the facility is economically infeasible. If so, there may be a duty to share such an essential facility on fair terms, unless there is a legitimate reason to deny access to the facilities. Thus, for example, a distributor might bring a lawsuit against an interstate pipeline for refusing to carry gas that had been purchased directly from an out-of-state producer, even though the pipeline would be paid a fair fee for its transportation services. The pipeline might legitimately refuse access if by doing so its ability to fulfill its obligation to serve its customers would be impaired. Some analysts believe that interstate pipelines may be essential facilities, as interpreted by the federal courts, and may therefore be required to share their facilities and act as contract carriers.⁴⁴ They contend that the essential facility doctrine provides an important means for promoting more effective competition in the gas market.

Section 3 of the Clayton Act declares exclusive contracts for the sales of goods unlawful if the contracts substantially lessen competition or tend to create a monopoly in any line of commerce.⁴⁵

⁴³Sherman Antitrust Act, 15 USC sec. 2.

⁴⁴See Jeremiah Lambert and Natalie Gilfoyle, "Reforming Natural Gas Markets: The Antitrust Alternative," Public Utilities Fortnightly, May 12, 1983, pp. 15-20.

⁴⁵Clayton Act, 15 USC sec. 14.

As argued above, exclusive contract provisions in producer-pipeline contracts might tend to be anticompetitive and hence violate antitrust laws.

Many of the revisions in producer-pipeline contracts that might be caused by threat of private antitrust litigation are now being considered in legislative proposals before the Congress. Should the legislative proposals fail, some analysts contend that the threat of private antitrust litigation will remain as an inducement for restructuring the gas market.

The interstate pipelines' defense against antitrust suits and the essential facilities doctrine in particular is likely to be that "under the controlling decisions of the (U.S.) Supreme Court, it is undisputed that matters subject to a pervasive scheme of public utility common carrier regulation are not subject to the antitrust laws."⁴⁶ So long as the natural gas industry is subject to pervasive federal and state regulatory control, federal antitrust laws may not apply. This exemption from the application of antitrust laws is called the pervasive regulation doctrine. The purpose of the doctrine is to prevent the courts from setting up conflicting guidelines for companies that are already subject to pervasive supervision by a governmental agency.

The pervasive regulation doctrine, however, does not apply to every action of a regulated utility. Some cases seem to suggest that the pervasive regulation defense does not apply to independent actions taken by a company if such actions initiate a monopolizing activity.⁴⁷

⁴⁶See *Southern Pacific Communication Co. v. American Telephone & Telegraph Co.*, 556 F. Supp. 825,1095 (D.D.C. 1983).

⁴⁷See *MCI Communications Corp. v. American Telephone and Telegraph Co.*, 4 Antitrust & Trade Reg. Rep. (BNA) 112 (7th Cir 1983), and *Phonetele, Inc. v. American Telephone & Telegraph Co.*, 664 F2d 716 (1981).

As the wellhead price of gas is deregulated pursuant to the provisions of the NGPA, the pervasive regulation defense would tend not to apply to producer-pipeline contracts. In addition, producer-pipeline contracts under the NGPA are voluntary arrangements that are rarely reviewed by the FERC. Consequently, the pervasive regulation defense may not apply even now.

Institute Net-Back Billing

Some interstate pipeline companies and some state commissions have suggested that pipelines and producers consider so-called net-back billing in their contract negotiations. To understand this concept, some analysts contrast it to the current add-on method by which final user prices are determined. That is, today's gas prices reflect the federally controlled wellhead price of gas to which federally approved transportation charges are added. The resulting city-gate price is the base to which state regulators add local distribution costs.

The net-back billing approach is suggested because gas must be priced competitively to customers or else they will switch fuels. In reality, the competitive price of gas is determined in the context of an entire constellation of alternate fuel prices and reflects both fuel switching and conservation behavior. Those who advocate net-back billing, however, are usually willing to simplify matters and use the price of number 6 fuel oil (resid) as the industrial market clearing price for natural gas, with number 2 fuel oil performing the same role for the residential sector. In the commercial sector, it is a combination of these two fuel oils. Having established the competitive, final user price, the regulated cost of distribution and transmission can be subtracted to find the wellhead price that corresponds to competitive final-user prices.

The method advocated by a spokesman for the Natural Gas Pipeline Company is illustrated in table 7-2. The procedure is to subtract average distribution and transmission margins from the competitive burner-tip price. The numbers are for illustrative purposes only and may not reflect actual regulatory cost allocation at the distribution and transmission levels. The example shows the calculations beginning with the assumed burner-tip prices, which then yield sectoral wellhead prices. The single, market clearing price at the wellhead is found as a weighted average of the sectoral prices using each sector's fraction of sales as weights. In this example, the average wellhead price is \$3.91. Note that if this were the wellhead price, adding transmission and distribution margins does not yield final user prices exactly equal to the cost of the alternative fuel, although the result is quite close.

To date, this type of calculation has been suggested by pipelines and to a lesser extent by some state commissions as a way of improving the buyer's bargaining position in negotiations with producers. While no one has suggested that wellhead prices be regulated in exactly this manner, Representative Byron's bill, (H.R. 482, described in chapter 4) has some net-back features. The difficulty that would be encountered if federal regulation were actually to adopt a net-back billing procedure is that while alternate fuels provide a good indication of competitive prices, they are by no means the sole determinant. In addition, the identity of the alternative may change as circumstances do.

Rather, the purpose of net-back billing seems to be related to the criticism that the current structure of the natural gas industry impedes the flow of price signals from final users to producers. One way to improve this flow would be to increase the contract carriage role of the pipelines since distributors and producers then would negotiate directly. Some pipelines' advocacy of net-back billing is a

TABLE 7-2
NET-BACK BILLING
(\$ per million Btu)

	<u>Industrial</u>	<u>Commercial</u>	<u>Residential</u>
Cost of Alternate Fuel at Burner Tip	\$5.00	\$6.50	\$7.00
Average Distribution Margin	-1.00	-1.25	-1.50
Average Transmission Margin	<u>- .15</u>	<u>-1.28</u>	<u>-1.57</u>
Average Wellhead Price	3.85	3.97	3.93
% of Sales	40%	20%	40%
Sales Weighted Average Market Clearing Wellhead Price	$.4 (3.85) + .2 (3.97) + .4 (3.93) = \3.91		

Source: Adapted from Exhibit A, Charles Eberst, "The Changing Environment in Natural Gas Pipeline Rate Designs--A Marketing Viewpoint," Speech at Fourteenth Annual Institute of Public Utilities Conference, Williamsburg, VA, December 1982.

suggestion for improving price responsiveness that does not require any change in the industrial organization. In effect, net-back billing may be the pipelines' argument that arrangements such as contract carriage are not needed.

Support Incentive Rate Designs

State commissions may want to participate in an FERC hearing on incentive rate designs for pipeline companies. The Federal Energy Regulatory Commission has proposed instituting an incentive rate design for pipelines as one means for handling protests against the automatic pass-through to consumers of the cost of large amounts of

unregulated natural gas.⁴⁸ Recently, consumers have been attacking pipeline gas purchasing practices with some success. For example, the Columbia Gas Transmission Corporation may not be permitted to pass along automatically to customers some \$481 million dollars in gas costs that were deemed excessive by an FERC judge.⁴⁹

The FERC is seeking to develop a rate design that will shift the risks associated with pipelines being underutilized from consumers to the pipeline companies. At present, as a result of purchasing practices by many companies and automatic pass-through allowances, prices have become so high that some large industrial gas users are forced to switch to cheaper fuels. This results in a smaller number of customers available to pay the pipeline's fixed costs. The FERC now feels that it may be time to exercise its ratemaking authority to protect customers from these imprudent gas purchasing practices: "The Commission ... could establish a rate design that would make the recovery of the pipeline's fixed costs and full return contingent upon its success in avoiding load loss.... This would be giving the company an incentive to minimize its gas purchases in a way that would be consistent with assuring long-term gas supplies."⁵⁰ The exact form of this innovative rate design has not yet been decided, but it will be patterned after the Civil Aeronautics Board load factor rate designs of the early 1970s that had the effect of shifting the risk of underutilization from customers to stockholders.

⁴⁸Federal Energy Regulatory Commission, "New Approach Set for Challenging Buying Practices," Monitor, October 18, 1982, p. 7.

⁴⁹National Association of Regulatory Utility Commissioners, "FERC Judge Finds Abuse in Pipeline Takes of High-Priced Gas," NARUC Bulletin No. 2-1983, January 10, 1983, p. 7.

⁵⁰Federal Energy Regulatory Commission, "New Approach," Monitor, op. cit., p. 7. For further discussions and citations, see appendix C.

Protect State Authority under Federal Deregulation

State regulators may need to monitor proposed federal legislation to protect the scope of state authority for regulating the gas industry. The major federal prohibitions on state regulation of the natural gas industry have come from the Supreme Court and its interpretation of the Commerce Clause of the U.S. Constitution. That clause gives the Congress the power to regulate interstate commerce, and in a number of cases the Court has struck down various state laws, usually claiming that they interfered with the flow of commerce between the states and thus intruded upon the Congress's prerogative.

As discussed in appendix B, the history of government regulation of the gas industry in the United States has been in part a struggle between federal and state governments for jurisdiction. For example, in 1911 the Court struck down an Oklahoma statute that had prohibited gas produced in that state from being exported to other states. In 1923, a West Virginia law requiring the state's producers to meet the demands of West Virginia customers before selling gas to other states was declared unconstitutional. In 1921, the Court held that a state could not tax gas flowing in interstate commerce. In 1924, the Court decided that states could not regulate the sale, transportation or delivery of natural gas in interstate commerce even in the absence of federal regulation.⁵¹

Importantly, however, the Court has upheld state laws intended to promote the conservation of gas.⁵² The Court upheld a state attempt, for example, to set minimum prices for gas taken from a field within

⁵¹See *Oklahoma v. Kansas Natural Gas Company*, 221 U.S. 229 (1911); *Pennsylvania v. West Virginia*, 262 U.S. 553 (1923); *United Fuel Gas Company v. Hallanan*, 257 U.S. 277 (1921); *Missouri v. Kansas Natural Gas Company*, 265 U.S. 298 (1924).

⁵²*Ohio Oil Company v. Indiana (No. 1)*, 177 U.S. 190 (1900).

the state over the argument that the state action violated the Commerce Clause. The rationale for the state policy included conservation--low prices would make the state's attempts to enforce conservation more difficult. In addition, the state argued that low prices might lead to a gas well being abandoned before all its gas had been recovered.⁵³ But, the Court established limits on state powers to set minimum prices in another case. In 1955, the Court struck down a state attempt to set minimum prices for gas destined for interstate commerce.⁵⁴

This review shows that the courts, especially the Supreme Court, have over the years placed important limits on state efforts to regulate natural gas. The courts have allowed state efforts to regulate production prices for purposes of conservation, but have struck down such regulation if it would interfere with interstate commerce.

An important related question is whether states can set minimum prices in the absence of federal wellhead price controls. A study by the Congressional Research Service and The National Regulatory Research Institute notes with respect to that issue that

while the early Commerce Clause cases suggest that such a result may be deemed to interfere with interstate commerce, the abandonment of the significant form of Federal regulation may permit a result whereby producing states are able to determine either directly or indirectly the price of natural gas. ⁵⁵

⁵³Cities Service Gas Company v. Peerless Oil and Gas Company, 340 U.S. 179 (1950).

⁵⁴Natural Gas Pipeline Company v. Panoma Corporation, 349 U.S. 44 (1955).

⁵⁵Natural Gas Regulation Study, op. cit.

The study notes an analogous federal court case involving a Connecticut law that had imposed a gross receipts tax on oil refiners and distributors in Connecticut. The law also prohibited the companies from raising their wholesale prices in that state. Some of the petroleum products covered by Connecticut's law were subject to federal regulation under the Emergency Petroleum Allocation Act. The federal controls, however, had been removed, and the District Court noted that this decontrol by the federal government was an indication that the products were to be free of all price regulation and subject to an unregulated free market. The court stated that Connecticut's law was in conflict with the federal government's intentions and consequently the court nullified it. The study notes that "decontrol of natural gas might not prevent state regulatory actions in the vacated zone of regulation unless Congress specifically preempts state action or manifests a very clear intent on the matter."⁵⁶

An important point is that the scope of a producing state's authority to regulate prices under federal deregulation is not as broad as some may have thought. The Congress addressed this issue in the Natural Gas Policy Act. Section 602(a) states that:

Nothing in this Act shall affect the authority of any state to establish or enforce any maximum lawful price for the first sale of natural gas produced in such state which does not exceed the applicable maximum price, if any, under title I of this Act.

The conference committee report noted that such state authority would extend to the operation of indefinite price escalator clauses. The conference report, however, also stated that such state authority would apply only to gas in intrastate commerce. The conference report

⁵⁶Ibid.; see also Mobil Oil Corp. v. Dubno, 492 F. Supp. 1004 (D. Conn. 1980).

also stated that "the Congress enacts this provision with a recognition that it is ceding its authority under the commerce clause of the Constitution to regulate prices for such production to affected states."⁵⁷

Section 602(a) of the NGPA would thus seem to provide a justification for state regulation, within limits, of production prices for intrastate gas. In reality, this provision does nothing more than allow producing states to regulate what they had already been regulating--old, intrastate gas. The importance of section 602(a) is that it exempts such gas from the commerce clause.

A recent Supreme Court ruling provides further guidance on the scope of state powers under current law. The case involved a Kansas law prohibiting the consideration of either ceiling prices set by the federal government or of prices paid in the state under other contracts when the parties to a contract applied its price escalator clause. This statute had been enacted after the passage of the NGPA, but the contract between the two parties, the Kansas Power and Light Company and its gas supplier, the Energy Reserve Group, Inc. (E.R.G.), had been in force before the NGPA. The price escalator clauses of the contract stated that if the government sets a price for gas that is higher than the price set in the contract, then the contract price would be increased to the government price. However, the seller of the gas could have the contract price redetermined no more often than once every two years. When the Energy Reserve Group tried to raise its prices to levels allowed by the NGPA, Kansas Power and Light claimed that such action was not allowed by the state law.

E.R.G. sued, but the state courts ruled that the federal price ceilings set under NGPA did not activate the contract's price

⁵⁷U.S. Congress, House, Conference Report on Natural Gas, report no. 95-1752, 95th Cong., 2nd sess., 1978, pp. 124-125.

escalator. The U.S. Supreme Court affirmed this decision, holding that the Kansas law did not violate E.R.G.'s contract rights and did not violate the U.S. Constitution's commerce clause. The Court stated that the law was based on a legitimate state interest, which was the state's police power to protect its citizens who consumed natural gas from escalating gas prices caused by deregulation. In the view of the Supreme Court, Kansas was trying to balance the need for incentives to promote gas production with the need to protect consumers.⁵⁸

Any ceiling prices that the states may set for intrastate gas must be below those set by the federal government under title I of the NGPA. Since the passage of the NGPA, the Supreme Court has been silent about whether states would be allowed to regulate, either directly or indirectly, gas in interstate commerce that has been or will be deregulated pursuant to the NGPA. Because section 602(a) has exempted old intrastate gas from the commerce clause, one might expect that clause to apply now to gas in interstate commerce. The Congress probably intended that producing states would not be allowed to regulate directly the price of gas in interstate commerce, including the price of all new gas. It is unclear, however, what the Congress's intention is with respect to indirect state regulation of the price of interstate gas.

Expand Energy Assistance Programs

Decontrol of natural gas prices is particularly burdensome to low income residential customers. If natural gas is used for residential heating, the fraction of family income spent on natural gas is about

⁵⁸See the discussion of this case in "Review of Current Cases: Supreme Court Upholds Limit on Price Escalator Clauses," Public Utilities Fortnightly, March 3, 1983, p. 54, and "Supreme Court Report," American Bar Association Journal, 69:524.

five times higher for low income families than for those of average income.⁵⁹ Thus, a rise in natural gas prices creates relatively greater difficulties for low income customers. Energy assistance programs are available to alleviate this burden for some. State regulators may want to advocate federal actions for increasing the amount of assistance or the number of eligible persons, as natural gas prices rise.

At the federal level, the U.S. DOE's Division of Weatherization is now the lead agency for federal weatherization programs. Other emergency fuel assistance may be obtained from the Energy Crisis Assistance Program and from special programs designed to make one-time assistance payments to recipients of Supplemental Security Income. The Department of Health and Human Services also allocates federal monies to states for their various energy assistance uses.⁶⁰

The Crude Oil Windfall Profits Act earmarked 25 percent of the windfall profits tax revenues for fuel assistance uses. This could yield a possible \$4.6 billion for aid to poor and elderly energy consumers for the next fiscal year. However, the federal budget has only included \$1.3 billion, or 28%, of the total amount that could be allocated for fuel assistance. Increasing the allotment would, of course, increase the effectiveness of most federal and many state programs, but with the present administration and the state of the economy, this reallocation appears unlikely to some observers.⁶¹

⁵⁹American Gas Association, "Cost of Immediate Total Wellhead Price Decontrol of Natural Gas to Low Income and Disadvantaged Groups," Energy Analysis (Washington, D.C.: April 9, 1981), p. 2.

⁶⁰Sweet, "National Energy Policy and Poor and Elderly Consumers," op. cit., p. 21.

⁶¹National Association of Regulatory Utility Commissioners, "Wisconsin PUC Asks Reagan to Increase Fuel Aid", NARUC Bulletin No. 2-1983, January 10, 1983, p. 25.

In addition to direct aid, the federal government assists states in developing energy conservation and weatherization measures. Due to the diverse conditions among the various states and regions of the nation, the federal government believes that a program administered totally by the federal government "would not be as effective as one tailored to meet local requirements."⁶² Consequently, federal conservation and weatherization plans provide technical and financial assistance for comprehensive state energy conservation plans, which, in turn, provide guidelines for states to establish, through the public utilities, conservation plans for residential energy consumers, provide conservation plans for government buildings, schools, and hospitals, and provide emergency energy conservation plans to prepare for the possible future energy shortages.

Comprehensive state energy conservation programs provide technical and financial assistance for specific state initiatives. Financial assistance comes in the form of grants from the Department of Energy (DOE) for which states must apply annually. The grants are based on state population and the estimated energy savings of the specific plans. Technical assistance includes thermal efficiency standards for new and renovated buildings, new weatherization methods and materials, and new public education methods for increasing residential use of conservation methods.⁶³

The Residential Conservation Service (RCS) program was established on November 9, 1978 by Part 1 of the National Energy Conservation Policy Act and amended by Subtitle B of Title V of the Energy Security Act on June 30, 1980. This program requires large electric and natural gas utilities to inform residential customers of available energy conservation and renewable resource measures and

⁶²10 CFR Part 420.1.

⁶³Ibid.

their benefits, to offer energy audits, and to arrange for financing and installation of those conservation measures. However, the federal government allowed individual states to elect whether or not they would participate in this program. The Residential Conservation Federal Standby Plan (FSP), proposed in November 1982, will, if approved, give the DOE, instead of the state lead agency, the authority to undertake organization, implementation, and enforcement of the RCS plan in states not choosing to participate or not adequately participating in the present RCS plans.⁶⁴

Also on the federal level, section 1023 of the Omnibus Budget Reconciliation Act of 1981 amended the Power Plant and Industrial Fuel Act of 1978 by adding section 808, a conservation plan for electric utilities that use natural gas as a primary energy source.

Section 808 requires utilities, which own or operate or plan to operate an existing or planned utility that uses or will use natural gas as a primary energy source, to develop and submit to the DOE a plan to conserve electric energy.

(This) plan must set forth the means to achieve the conservation of electric energy or a level equal to 10 percent of the electric energy output of the utility sold within its own system, which was attributable to natural gas during the four calendar quarters ending on June 30, 1981. Approved plans must be fully implemented during the five year period following DOE approval.⁶⁵

In modifying these energy assistance programs or in fashioning others, several regulatory issues are worthy of consideration. The rights to buy old gas are distributed unevenly across pipelines and distribution companies. Under the NGPA, natural gas price increases are likely to be larger for those customers who happen to be served

⁶⁴See 47 Fed. Reg. 53634 (1982).

⁶⁵47 Fed. Reg. 53768-69 (1982).

by suppliers that have relatively small quantities of old, price controlled gas. A truly compensatory heat subsidy for low income families would account for this. Consideration of a family's income and heating bill may adequately deal with this inequity; however, care should be taken to avoid weakening the family's incentive to conserve gas. That is, a heating subsidy tied directly to a gas bill effectively reduces the price of gas and consequently distorts conservation decisions. For example, a subsidized family considering insulating its own residence would know that the subsidy would be reduced by the insulation, thus penalizing voluntary conservation. Such a distortion might be avoided by linking the subsidy to a previous year's gas bill so that the subsidy amount is not affected by subsequent usage.

Likewise, direct subsidies of conservation and weatherization programs, whether by direct assistance, income tax credits, or low interest loans for insulation, have the unfortunate side effect of distorting consumer choices. Information programs, such as energy audits, on the other hand, facilitate conservation decisions and do not distort the price of the conservation materials themselves. Consequently, there is likely to be little if any resource misallocation associated with them.

Informing the Public

In addition to the various actions and options just discussed, a commission might choose to take a more active role in informing the public about regulation of the gas industry. State public utility commissions are in the extremely uncomfortable position of appearing to customers to set natural gas rates when in reality state regulators have relatively little discretion about the matter. The largest component of the price of natural gas is the cost at the city gate. Table 7-3 shows the 1982 city-gate and end-user prices for the 10 utilities discussed in chapter 6.

TABLE 7-3

1982 CITY-GATE AND RETAIL PRICES FOR TEN UTILITIES
(\$/mcf)

Utility's Region	City- Gate Price	Resi- dential Price	City-Gate Price as a Percent of Residential Price	Commer- cial Price	City-Gate Price as a Percent of Commercial Price	Indus- trial Price	City-Gate Price as a Percent of Industrial Price
N. Eng.	4.36	7.70	57	7.25	60	7.25	60
E.N. Centr.	4.10	7.20	57	6.38	64	5.18	79
Mid. Atl.	3.19	4.85	66	4.66	68	4.39	73
Sou. Atl.	3.83	5.75	67	4.65	82	4.36	88
Midwest	3.30	4.30	77	4.15	80	3.86	85
Southwest	2.41	4.04	60	3.90	62	3.36	72
Central	3.53	4.78	74	4.28	82	3.58	99
N. Centr.	3.09	4.02	77	4.38	71	4.47	69
West	3.92	4.45	88	5.55	71	5.22	75
N. West	4.28	5.97	72	5.43	79	4.78	89

Source: NRRI telephone survey of 10 gas companies, April 1983

The table also shows the fraction of retail prices contributed by the distributor's cost of purchased gas. The cost at the city gate ranged from 57 to 88 percent of the residential price and was about 69 percent on average in 1982. Because commercial prices are typically lower than residential, the city-gate price was typically a larger component of commercial bills, ranging from 60 to 82 percent and averaging 72 percent. That federally controlled portion was even larger in relation to industrial prices, with a range of 60 to 99 percent and an average of 80 percent. Hence, 70 to 80 percent of most customers' gas bills is beyond the control of state regulators. State PUCs may wish to inform consumers of such facts, perhaps by including an occasional insert in the monthly gas bill or through news conferences, television interviews, or newspaper stories.

In addition, state commissioners may wish to direct their staffs to make some hypothetical calculations that would show consumers how much their natural gas bill would change if the allowed rate of return were adjusted. The reasoning here would be that the principal, conventional control exercised by public utility commissioners over the rates of regulated monopolies is subject to legal limitations. By examining a plausible range of the allowable rates of return and the associated prices, the PUC could calculate the reduction in the average bill that results from a particular reduction in the allowed rate of return. The calculation would yield a very small bill change. The point to be emphasized is that the PUC's discretionary authority is, in fact, much narrower than even that implied by the city-gate price percentage. Most of the distributor's non-gas costs are for labor, operations and maintenance expenses, taxes, and so on. Any practical exercise of discretionary authority yields a much smaller change than that implied by the distributor's portion of the cost. Care must be taken, however, in presenting such an argument to customers concerning the allowed rate of return. The commission would need to emphasize that, if the allowed rate of return is as low as it

can be, then lowering it further would confiscate the stockholder's capital. In that context, if the rate of return were arbitrarily reduced, thus illegally confiscating some of the owner's capital, the resulting price reduction would illustrate the rather severe limits to the state regulators' power to reduce gas rates.

Beyond the commission's traditional role in setting the allowed rate of return, the commission could inform the public of any unusual efforts it or other state commissions are making to investigate gas rates or to present testimony before the FERC or the Congress.

A useful document for a commissioner interested in improving communication with the public is the NARUC Public Information Manual,⁶⁶ prepared by the NARUC Staff Subcommittee on Public Information. Perhaps the most important part of good public relations is to make the public understand that the PUC is accessible to hear individual problems and complaints as well as those of a more general nature. There are numerous ways to facilitate the flow of information between the commissions and consumers. Many PUCs have a consumer complaint division. Others maintain a toll-free hotline to provide information on where to go to get energy audits, weatherization services, and conservation information. Such a hotline service can be useful to consumers trying to sort through what is frequently a bewildering array of federal, state, and local agencies as well as the services offered by the utilities themselves or private contractors.

⁶⁶J.E. Davis and C.K. Howle, Public Information Manual (Washington, D.C.: NARUC, n.d.).

Some commissions have conducted informal hearings throughout the state on such matters as utility disconnections, the burden of gas bills on low income consumers, and repayment plans for customers who have fallen behind in their payments. Such hearings demonstrate that the commission is genuinely interested in listening to consumer problems and in trying to fashion a solution.

In a time of rapid increase in gas prices, there will naturally be many consumers who suddenly find that their previous life style is now quite expensive. The changing of people's expectations is never an easy matter. The PUCs can assist those people who are confused and are trying to adjust to a new set of economic circumstances by facilitating the flow of information about gas prices, insulation, weatherstripping, government assistance programs, and so on. According to many observers, the largest increases in gas prices probably have already occurred. If gas prices do indeed level off in the future, the consumer's need for information is likely to diminish. PUCs, then, may be called upon to raise rates less frequently in the future and somewhat less attention could be devoted to providing the public with information.



CHAPTER 8

SUMMARY

Federal regulation of natural gas wellhead prices resulted in natural gas shortages in the interstate market during the early 1970s. By 1977, interstate pipelines could meet only 75 percent of their contractual requirements. The need to alter the then existing regulatory framework was indisputable. In 1978, the NGPA was enacted as a compromise between advocates of total decontrol of wellhead prices and those who wanted continued price controls. It calls for a phased, partial decontrol of gas wellhead prices. The NGPA creates over 20 categories of gas; it provides for gradually rising ceiling prices for most categories of gas, the immediate decontrol of high-cost gas, the decontrol of new gas beginning in 1985, and the permanent price regulation of both old interstate and some old intrastate gas after 1987.

After the NGPA's enactment, retail gas prices increased more rapidly than expected under the NGPA's gradually rising gas price ceilings. For example, in 1982 alone, real retail prices increased an average of 18 percent nationwide. Even greater price increases may occur in 1985 when new gas is decontrolled.

The natural gas market has operated inefficiently under the NGPA. The unexpectedly sharp rise in natural gas prices is only one symptom of the disarray in the natural gas market. The many NGPA ceiling prices and the industry's new use of old contractual arrangements do not permit the natural gas market to function as a normal competitive market.

Both short-term and long-term ordering problems exist in the natural gas industry. Most short-term market ordering problems, which prevent the natural gas market from operating as an effective spot

market would operate, result from gas price inflexibility induced either by the NGPA's prespecified ceiling prices or the industry's contractual arrangements.

The NGPA method for adjusting the ceiling price on new gas by a fixed real percentage each year does not allow prices to respond to changing conditions in the gas industry. Only by sheer chance will the 1985 ceiling price for new gas be close to the market clearing price of deregulated gas. Thus, a disruptive fly-up of natural gas prices in 1985 is possible, if the NGPA ceiling price is too low.

Clauses in producer-pipeline contracts also create short-term market ordering problems. Take-or-pay clauses offer producers compensation in the form of options to sell gas in the future at a specified price regardless of demand. Since these options have a value, they have the effect of allowing the pipelines to pay a price above the NGPA ceiling price for new gas. The expected greater volatility of new gas prices after 1985 increases the value of such options granted to producers through take-or-pay agreements. This financial compensation aspect of take-or-pay arrangements has become more important, relative to their traditional function of limiting risks borne by producers, because of NGPA ceiling price constraints on the bidding price for gas. The market ordering problems associated with price escalator clauses are largely due to the inflexibility associated with most favored nation clauses and oil parity clauses. When the substitution relationship between natural gas and fuel oil changes or is estimated inaccurately, an oil parity clause cannot correctly serve as a proxy for the market price of gas.

Pipeline-distributor contracts transfer market ordering problems at the wellhead past the city gate to gas customers. Minimum bills allow pipelines to pass along to distribution companies the risks associated with take-or-pay contracts. Purchased gas adjustment clauses allow any price fly-up to flow quickly through to customers

without a market test of whether they are willing to pay the resulting high prices. The demand charge provision found in pipeline-distributor contracts permits the cost of pipeline excess capacity to flow through to remaining customers, which further discourages consumption and aggravates any existing capacity utilization problem.

In addition to these aspects of the natural gas market that prevent it from operating efficiently in the short-run, there are long-term market distortions that result from such factors as rolled-in pricing, the uneven distribution of gas cushion, supply ordering problems, and demand ordering problems.

A policy of rolled-in pricing results in several important market characteristics. Expensive gas can be subsidized by the low prices for old gas. Then, expensive gas can be produced at an expense greater than the value it holds for customers, resulting in excessive development of expensive gas supplies and wasteful use of gas. Another characteristic of a market with rolled-in pricing, however, is that the rolled-in price is less than the price that would occur in a competitive market. Thus, consumers benefit from average, rolled-in pricing at the expense of producers who receive lower profits. The profits that are denied to producers by rolled-in pricing are used to subsidize consumption.

The uneven distribution of the gas cushion creates inequity among customers in different regions. Since wellhead prices are rolled-in separately for each pipeline, customers served by those pipelines with a larger fraction of old, low priced gas are better off than those who are served by pipelines with more expensive mixes of gas. This inequity would be largely eliminated if all gas wellhead prices were decontrolled. However, even if the NGPA remains unchanged, the problem will gradually disappear in the late 1980s and early 1990s as the portion of old gas in the supply mix declines.

The numerous NGPA categories of natural gas and their ceiling prices create perverse incentives for new natural gas wells to be developed in other than the increasing order of their cost. More expensive deep wells are completed before all less costly opportunities are exhausted. Also, producers have an incentive to have their wells redefined to fit a more expensive NGPA category.

Demand ordering problems exist, but are of less importance than other market distortions. The incremental pricing provision of the NGPA initially imposes the burden of higher prices on non-exempt large boilers. Errors in the maximum surcharge absorption capacity could result in natural gas prices exceeding the price of the alternate fuel and loss of industrial customers. Also, states with large MSAC accounts can reallocate the distributor's fixed cost so as to capture the benefit of these accounts for state residents only.

The controversy over rising gas prices and the various market distortions has led to demands for corrective legislation. Forty-seven bills proposing corrections were introduced in the Congress in the first six months of 1983. A recurring policy issue in the legislative debate is the tradeoff between increased economic efficiency and fairness to a particular constituency. One set of legislative proposals deals directly with the existing NGPA control of gas wellhead prices. The major pricing options are retaining the NGPA's phased, partial decontrol plan with some modifications; total decontrol, either immediate or phased; and the extension of price controls. In general, greater market efficiency is achieved by removing gas price controls, but this may be unfair to gas customers who invested in gas-consuming equipment under the expectation of controlled prices.

Even complete decontrol of wellhead prices would not result in an economically efficient gas market because of difficulties in long-term contracts negotiated under the NGPA and because a pipeline is

frequently the only buyer available to a producer and the only seller available to a distributor. A second set of legislative proposals would modify contract provisions in the natural gas industry. Lower take-or-pay provisions and weakening of certain escalator clauses can increase market efficiency. But, these actions are unfair to producers who are denied the value implicit in such clauses. The third set of legislative proposals deals directly with the market position of pipelines. Perhaps the most economically efficient approach is to make pipelines common carriers and to allow distribution utilities to purchase gas directly from producers in a competitive market, but this approach may also treat pipelines unfairly by denying them the right to own the gas they carry.

The effect on city-gate prices of the legislative proposals for changing NGPA price regulations can be examined using economic forecasting models. Three useful models are DOE's Midterm Energy Forecasting System, ICF's Two-Market model for natural gas, and the AGA's TERA model. These three models represent the state of the art in natural gas price forecasting, and the results of studies using them represent the best publicly available information on how government policies affect future gas prices.

The 1985 U.S. average city-gate price forecast by MEFS is about \$5.32 per mcf (in 1980 dollars) assuming that the NGPA remains and that medium economic conditions occur. These forecasts are very sensitive to assumptions about major economic variables. For example, if the 1985 price of oil is as low as \$26 per barrel (in 1980 dollars) instead of the mid-range value of \$33 per barrel, the MEFS forecast of the U.S. average 1985 city-gate natural gas price is \$4.22 per mcf (in 1980 dollars) instead of \$5.32. Thus, the future level of the world oil price is an important determinant of natural gas prices. In addition, the strength or weakness of the U.S. economy has a significant effect on natural gas demand, and hence on price. One

study projects a 70 percent difference in 1985 city-gate prices depending on whether demand is normal or slack.

The average city-gate price in 1985 under total wellhead price decontrol is estimated to be only 12 percent above the price under the NGPA. As a consequence, forecasts of city-gate prices are dominated by assumptions about world oil prices and the level of national economic activity. The largest probable real price increase between 1980 and 1985 appears to be about 125 percent under the NGPA. The lowest likely real increase during this five-year period is 50 percent. The increase in 1985 city-gate price with a change from the NGPA to early total decontrol is between 0 and 25 percent, with 12 percent most likely. While a 12 percent price increase is not small--it represents billions of dollars flowing between states--the impact of a federal choice between these two deregulation alternatives is small compared to the impact of national and world economic variables.

The NRRI developed a gas price model that translates regional 1985 city-gate prices into regional forecasts of customer rates. The model uses separate demand functions for residential, commercial, and industrial customers in each region based upon price elasticities estimated by the DOE and used in the MEFS model. Data on actual prices, operating and maintenance costs, plant-in-service costs, taxes, and allowed rates of return for a representative utility in each of ten regions were incorporated into the model. The equilibrium retail price and load for each customer class in each region was found through an iterative solution procedure.

The analysis produced several significant results. Residential gas rates in 1985 are 9 to 14 percent higher under total decontrol than would occur with the NGPA unaltered, and residential gas bills are only 5 to 9 percent higher. Total decontrol is not expected to be much more costly to gas consumers than phased, partial decontrol under the NGPA. Of course, these results are regional averages; a customer

served by a pipeline with a large gas cushion would experience greater increases. The results also indicate that in all ten regions public utility commissions control a relatively small proportion of burner-tip costs.

The effect of changing distribution company demand allocation methods was tested using the model. The choice between allocating demand costs according to the peak responsibility method and the average-and-excess demand method has a very small effect on burner-tip prices. In some regions, however, the reallocation of company costs from industrial to residential and commercial groups can give significant relief to the industrial group with a relatively modest cost to the other customer classes, but it always raises residential and commercial rates. The model produced no evidence of a spiral in which load loss leads to higher unit costs, which leads to more load loss and the eventual collapse of gas sales. Such an unstable situation, if it exists, would be due to a very high price elasticity of demand. None of the elasticities estimated by the DOE was so high as to cause an unstable situation.

The options available to public utility commissions for dealing with wellhead price deregulation are those that require direct commission action and those that require commissioner influence on state and federal gas policy and on public opinion. The options available to regulators directly include rate design innovations, such as lifeline rates. Altering fixed cost allocation policies to prevent fuel switching by major industrial customers shields price sensitive industrial customers but may not be justifiable on a traditional cost-of-service basis. In the results reported here, permanent shifting of industrial fixed costs to nonindustrial customers always leaves such customers worse off. But, this result may not hold in the case of a sudden, large loss of load triggered by a small price increase, which would be the case if industrial demand is so highly elastic as to be unstable.

Flexible rates can be used to keep industrial gas prices at competitive levels. These rates for large interruptible customers are negotiated on an ongoing basis or are tied to the price of an alternate fuel. At least eight commissions have approved such tariffs, which allow distribution companies to vary prices without specific commission hearings.

State commissions may choose to take a hard line with distribution utilities to provide an incentive for distribution utilities to seek less costly supplies. Distribution companies could be held accountable for their excess capacity and not be permitted to shift the risk of excess capacity away from stockholders by raising the demand charge per unit of sale.

As an alternative to direct action, public utility commissioners may help to shape state policy. Perhaps the most effective state actions include initiation or expansion of conservation and weatherization programs, increasing low-income heating subsidies, and requiring contract carriage for intrastate pipelines in gas producing states.

Since federal legislation has great impact on the natural gas market, public utility commissioners may want to participate in shaping federal policy. The choices of extending federal price controls on gas, sticking with the NGPA, and totally decontrolling wellhead prices involve tradeoffs between fairness to ratepayers and greater efficiency in the gas market. Altering contract arrangements such as take-or-pay provisions, indefinite price escalators, and most favored nation agreements is an area of growing legislative interest. Requiring common or contract carriage of gas by pipelines is another legislative option at the federal level. These latter actions can increase market efficiency, but may be unfair to producers or pipelines. Incentive rate design has been proposed for pipelines by the FERC to shift some of the risk associated with excess capacity

from consumers to pipelines. State commissioners may want to support such a proposal. A disproportionate share of the burden of federal actions to decontrol gas prices partially or totally falls on low income families whose proportion of family income spent on gas is five times higher than that of an average income family. Federal energy assistance programs could be expanded, perhaps using windfall profit tax revenue. State regulators may want to promote such federal policy.

Public utility commissions have limited authority to deal with rising natural gas prices and gas market distortions. About seventy percent of the average customer's gas bill is outside the authority of state regulators. Public information campaigns could stress the PUC's limited role as well as provide information about possible future gas prices, the availability of energy audits, weatherization and insulation programs, and government heating subsidies.

Of these various options, the ones that commissions might find most useful are the following:

- * Use flexible pricing--at least eight states have approved a tariff that allows distribution companies to vary gas rates at will, within floor and ceiling price limits, for some customers with alternate fuel capability.
- * Promote weatherization and conservation programs and low-income heating subsidies--even under moderate economic assumptions large gas price increases are forecast, and existing state and federal programs may be inadequate to provide relief.
- * Alter contract clauses--legislation drafted by the NARUC Committee on Gas and endorsed by the NARUC Executive Committee calls for altering clauses in producer-pipeline contracts that are believed to favor producers unduly.
- * Consider total deregulation--the relatively small effect (relative to the effect of economic conditions) of choosing between total decontrol and the NGPA may not justify continuing NGPA market distortions.

- * Support common or contract carriage--some form of contract carriage may provide useful information on the ability of distribution companies to deal with gas producers.

- * Inform the public--gas customers may have insufficient information about the ability of state regulators to control retail gas rates, about probable future gas rates, and about state and federal programs available for alleviating hardship.

APPENDIX A

GLOSSARY

The following is an explanation of terms that are used in this report.

Annual Inflation Adjustment Factor - According to the NGPA, a percentage or fraction used in adjusting the price of natural gas for inflation or, in some cases, to increase it more than the inflation rate. The adjustment consists of both an inflation factor, based on the quarterly percent change in the gross national product implicit price deflator, and a correction factor, based on the consumer price index. For some gas, a growth factor is also added to increase prices at a faster rate than that of inflation.

British Thermal Unit (Btu) - A unit of energy. It is the amount of heat required to raise the temperature of one pound of water by one Farenheit degree.

Btu Equivalent Cost of Number 6 Fuel Oil (resid) - The price per million Btu paid for number 6, high sulfur, residual fuel oil within the region under consideration.

Btu Equivalent Cost of Number 2 Fuel Oil - The price per million Btu paid for number 2, distilled, fuel oil within the region under consideration.

Burner-Tip Price - The price of natural gas that is faced by the customer.

Buyer Protection Clause - Any clause in a contract between a natural gas producer and purchaser that permits the purchaser (typically, a pipeline) to limit the price that it pays for gas.

Ceiling Price of Natural Gas - The maximum lawful price for which natural gas may be sold under Title I of the NGPA. Individual states have the right to set maximum lawful prices for natural gas as long as they are lower than those set forth in the NGPA; however, these would not be ceiling prices. Ceiling prices only pertain to the NGPA. For comparison, see "maximum lawful price."

City-Gate Price - The price of natural gas that the distribution company pays to its supplier; also, the average of such prices paid to several suppliers.

Common Carrier Status - Legal duty in which a transporter is required to carry the goods of anyone who seeks such a service. (The carrier is not allowed to carry its own goods.) If natural gas pipelines were to have such status, a pipeline would be required to transport gas from any producer seeking to use the pipeline. The pipeline would neither procure nor market the gas; it would be paid a fixed fee per unit volume of gas transported.

Completion Location - According to the NGPA, any subsurface location from which natural gas is being, or has been, produced in commercial quantities.

Contract Carrier Status - The status of a natural gas pipeline that transports gas from a producer to a buyer who have entered into a contract for the gas. Such status does not prevent the pipeline from purchasing other gas from producers on its own account; however, it does introduce an alternative whereby producers and distributors can negotiate the price of gas without involving the pipelines.

Cushion Gas - (also Base Gas) - The quantity of natural gas not normally recoverable from storage fields. It is used to increase the pressure in the underground reservoir in order to facilitate the removal of the non-cushion or "working gas." Cushion gas typically amounts to 58% of the natural gas reservoir's volume. For comparison, see "gas cushion."

Deep Gas - Natural gas produced from wells for which the surface drilling began after February 19, 1977 and for which the production depth is greater than 15,000 feet.

Demand Costs - Costs that are related to the ability to meet peak gas demand, such as the fixed costs of transmission and distribution capacity.

Elasticity (Own Price Elasticity of Demand) - The ratio of the percentage change in quantity of a product demanded to the percentage change in its price.

First Sale - According to the NGPA, a sale by a natural gas producer to any pipeline, local distribution company, or other entity, which precedes any other such sale. It can also mean a sale by any of these entities if it is the producer of the gas. The FERC has the right to define any sale as a first sale to prevent anyone from exceeding the maximum lawful price established under the NGPA.

Flexible Pricing - The setting of natural gas prices at a variable rate between specified floor and ceiling rates for industries capable of using an alternate fuel. This procedure is designed to allow distribution utilities to vary industrial gas rates so as to make gas prices competitive with alternate fuels and to discourage fuel switching.

Fly-up - A sudden increase in natural gas wellhead prices expected by some to occur with the lifting of NGPA wellhead price controls for some gas in 1985. For comparison, see "spike."

Fuel Switching - The shifting by energy customers with alternate fuel capabilities from their present fuel to an alternative for economic or availability reasons. In the case of natural gas, some analysts contend that industrial fuel switching will be severe upon deregulation.

Gas Cushion - A supply of low-priced natural gas. It may enable a pipeline to buy high-priced gas and sell the resulting mix at a marketable, average rate. For comparison, see "cushion gas."

High-Cost Gas - Natural gas designated under section 107 of the NGPA. It consists of gas from deep wells, Devonian shale, geopressurized brine, coal seams, or other sources designated by the Federal Energy Regulatory Commission as presenting extraordinary financial risks or production costs.

High Priority Use - According to section 401 of the NGPA, any use of gas in a residence or commercial establishment amounting to less than 50 mcf per day, any school, hospital or similar facility, or other use the curtailment of which would endanger life, health, or maintenance of physical property.

Horizontal Integration - The merger of firms that are in the same stage of an industrial process. For example, the merger of two natural gas production companies would be horizontal integration. For comparison, see "vertical integration."

Incentive Rate Design - A rate design for natural gas that attempts to shift the risks associated with a utility's being underutilized

from consumers to the utility. Such a rate could make the recovery of the utility's fixed costs contingent upon avoiding load loss, thus, giving the utility an incentive to alter its purchasing practices in order to keep customers on the system.

Incremental Pricing - According to phase I incremental pricing of the NGPA, the pricing of natural gas to large industrial boilers and other industrial gas users, as specified by the Federal Energy Regulatory Commission, at a rate that is higher than residential and commercial rates and lower than a ceiling price that is pegged to the price of alternate fuels (typically number 6 fuel oil). These industrial customers will bear the cost of high-priced gas up to this ceiling; however, once the ceiling price is reached, all other customers, including residential and small commercial users, will have to bear a portion of the higher gas costs. Phase II incremental pricing, which is not in effect as of yet, would increase the number of classes of industrial users subject to incremental pricing.

This differs from the use of the term "incremental pricing" prior to the enactment of the NGPA. During the mid-1970s, shortages of low-cost natural gas forced the curtailment of many industrial customers. However, higher-cost gas was available to ease curtailments. There were two methods used to pass through the costs of the higher priced gas to customers: rolled-in pricing, which consisted of taking a weighted average of the high- and low-cost gas prices and charging the same price to all customers; and incremental pricing, which consisted of charging the curtailed customers the higher prices associated with the additional high-cost gas if they were willing to pay such prices to ease curtailments.

A third use of the term "incremental pricing" is the standard use in economics. The incremental cost of a product is the increase in its total cost resulting from an increase in its

production large enough to require capacity expansion. Incremental pricing is the pricing of this product at its incremental cost.

Incremental Pricing Surcharge - The increase in gas price to industrial customers that are subject to the incremental pricing requirements of the NGPA.

Indefinite Price Escalator Clause - According to the NGPA, a provision in a contract between a pipeline and a producer providing that the price of gas under the contract be established or adjusted either by negotiation between the parties or by reference to the prices of other natural gas, crude oil, or some refined petroleum products.

Marker Well - According to the NGPA, a well from which natural gas was produced in commercial quantities at any time after January 1, 1970 and before April 20, 1977 excluding wells, the surface drilling of which began on or after February 19, 1977; also a well, the depth of which was increased by drilling on or after February 19, 1977 to a completion location at least 1000 feet below the deepest previous completion location.

Market Clearing Price - The price at which the amount of a product that suppliers are willing to sell equals the amount that purchasers are willing to buy.

Market-Out Clause - A provision of a contract between a natural gas producer and a pipeline that enables the pipeline to refuse without penalty to take gas that it cannot sell. After a market-out clause is exercised, the producer can sell the gas to the original pipeline at a lower renegotiated price, sell the gas to another pipeline after guaranteeing the original pipeline the right of first refusal, or, in some cases, cancel the contract.

Maximum Lawful Price - The maximum price that can be charged legally for natural gas at the wellhead. Maximum lawful prices for all categories of gas are specified in the NGPA. These are also known as "ceiling prices." Individual states have the power to set their own maximum lawful prices; however, these may not exceed the ceiling prices specified in the NGPA.

Maximum Surcharge Absorption Capacity (MSAC) - According to the Federal Energy Regulatory Commission, the amount of incremental surcharge an industrial customer could pay without exceeding the price of alternate fuels published by the Energy Information Administration of the Department of Energy.

Minimum Bill Provision - A provision in a contract between a pipeline and its customer, typically a distribution company, whereby the customer agrees to pay the pipeline at least a specified amount regardless of the amount of gas actually taken by the customer.

Most Favored Nation Clause - A provision in a contract between a gas producer and a pipeline that ties the contract price to the rates paid in other contracts that are in the same geographical area. The contract price can be tied to the highest contract price paid by any buyer in the same producing area, the highest contract price in the same producing area paid by any pipeline, or the average of the highest contract prices in the same producing area.

Near-Deep Gas - Natural gas produced from wells between 10,000 and 15,000 feet in depth.

Net-Back Pricing - A proposed system of determining the wellhead price of gas in which burner-tip prices would be set competitively with those of other fuels, particularly fuel oil; distribution and transmission costs would be subtracted from this burner-tip price to arrive at the wellhead price.

New Well - According to the NGPA, a gas well for which the surface drilling began on or after February 19, 1977 or a gas well in existence before February 19, 1977 for which additional drilling after this date increased the depth by at least 1,000 feet.

Off-System Sales - The sale of uncommitted natural gas by pipelines to distribution companies or others who are not regular customers.

Old Well - According to the NGPA, a gas well for which surface drilling began prior to February 19, 1977 and which was not increased in depth by more than 1,000 feet after this date.

Proration Unit - According to the NGPA, the portion of a natural gas reservoir, designated by the state or federal agency having regulatory jurisdiction over the production of such reservoir, that is effectively and efficiently drained by a single well.

Purchased Gas Adjustment (PGA) Clause - A clause in a rate tariff for pass-through to customers of increases in gas wellhead prices. This is used, instead of a rate case, in pipeline tariffs and distribution company tariffs and may be applied automatically or with some level of auditing by the regulatory commission.

Redetermination Clause - Provision in a contract between a natural gas pipeline and a producer specifying that upon deregulation the price of gas will be set according to the value of certain preselected factors, such as the average of the highest prices in contracts for a producing area or the price of number 2 fuel oil. This is one type of indefinite price escalator clause.

Regulatory Disallowance Clause - A type of buyer protection clause that allows a gas purchaser (typically, a pipeline) to reduce the price it pays for gas if the price called for is disallowed by the appropriate state or federal regulatory agency.

Rolled-In Pricing - The pricing mechanism under which a pipeline calculates a weighted average cost of all gas purchased, high-cost and low-cost, and charges this average-cost based price to its customers.

Rollover Contract - According to the NGPA, a rollover contract is a gas contract, signed after November 8, 1978, covering gas that was sold under a previous contract, which expired after November 8, 1978 at the end of a fixed term specified in the previous contract.

Shut-In Gas - Natural gas in a drilled well that is capable of being produced, but is not being produced.

Small Industrial Boiler Fuel Facility - According to the NGPA, an industrial boiler that uses natural gas at a rate that does not exceed 300 mcf per day or some smaller rate as specified by the Federal Energy Regulatory Commission.

Spike - A sudden increase followed by a sharp decrease in the price of a product. In the case of natural gas, this is expected by some to occur with the NGPA lifting of wellhead price controls on some gas in 1985. For comparison, see "fly-up."

Spud Date - The date on which surface drilling of a natural gas well begins.

Severance Taxes - Any severance, production, or similar tax, fee, or levy imposed on the production of a commodity by any governmental unit. In the case of natural gas, the governmental unit as defined by the NGPA consists of individual states, local governments under the authority of state law, or Indian tribes recognized as eligible by the Department of the Interior.

Stripper Well - As defined by the NGPA, a natural gas well that cannot produce unassociated gas at an average rate exceeding 60 mcf per production day without the aid of recognized enhanced recovery techniques. Usually, these are old wells drawing on largely depleted reservoirs.

Take-or-Pay Clause - A provision in a contract between a pipeline and a producer whereby the pipeline agrees to pay the producer for a specified percentage of the gas under contract regardless of whether the gas is actually taken. The term also applies to the same provision in a pipeline-distribution company contract.

Tight Formation - Gas bearing rock composed of sedimentary layers bonded in a manner that greatly impedes the flow of natural gas through the rock to the well. According to the NGPA, some gas from tight formations is eligible to be considered, under section 107 of the Act, as high-cost gas. A tight sands formation is a type of tight formation.

Unassociated Gas - Natural gas production unaccompanied by crude oil production; also called non-associated gas and dry gas.

Vertical Integration - The merger of firms that are in different stages of an industrial or other production process, resulting in the ownership of multiple steps in the process by a single entity. In the case of natural gas, a corporation that owns interconnected production, pipeline, and distribution subsidiaries is vertically integrated. See "horizontal integration."

Vintaging (also Vintaged Pricing) - The existence of varying prices for gas according to its year of production, as embedded in long-term contracts.

Wellhead Price - The price of natural gas charged by the producer at the wellhead. The wellhead price does not include certain costs of compressing, liquifying, gathering, processing, treating, or transporting gas allowed for by the FERC. The wellhead price also may not include a portion of state severance taxes.

APPENDIX B

GOVERNMENT REGULATION OF THE GAS INDUSTRY BEFORE THE NGPA

In order to understand fully the current controversy over the regulation of gas prices discussed in the early chapters of this report, it is necessary to have a grasp of the role of government in the gas market prior to the NGPA and of the issues that led to the enactment of the NGPA as a compromise between opposing viewpoints on the proper governmental role. Accordingly, this appendix contains a short history of the regulation of the natural gas industry by both the states and the federal government up to the passage of the Natural Gas Policy Act of 1978.

Natural gas has been on the regulatory agenda of local, state, or federal governments almost constantly for over a century. At various times during the past several decades, debate over the proper role of government in the industry has pitted producing states against consuming states, producers against pipelines, interstate pipelines against intrastate pipelines, and state regulators against federal regulators. Many of these divisions have lasted throughout the entire period.

The current controversy can be more readily appreciated in historical context. Throughout the decades, it has been recognized that the natural gas industry is complex and that the variety of interest groups makes policy formulation difficult and protracted. At the federal level, presidents of both parties, especially since Franklin D. Roosevelt, have attempted to formulate their own solutions to natural gas regulatory problems. The issue of the federal role in regulating the gas industry has been a highly divisive one in the Congress, reflecting the variety of interest groups that care about the issue. The U.S. Supreme Court has addressed the issue, handing down some important and at times controversial decisions. The states

were active in gas regulation long before the federal government, and could assume increasing importance when federal regulation is phased out.

An account of how government has dealt with the natural gas industry historically may be useful for understanding the roots of today's controversies. This material is covered in four sections: one on early state and local regulation, a second on the Natural Gas Act of 1938 (NGA) and what happened after its passage including a brief examination of the growing gas shortage of the 1960s and 1970s leading up to the emergency in the winter of 1976-77, a section on the evolution of the NGPA, and a final section on current state regulation. The emphasis is on the two major pieces of federal legislation: the major provisions of the NGA and the different interpretations of this Act by various interests and by the courts, and the formulation of gas legislation by the Carter administration and the subsequent debate, modification, and passage of the NGPA by the Congress. The detailed provisions of the NGPA are set out and explained in appendix C.

Early State and Local Regulation

As mentioned above, the natural gas industry has been regulated by various levels of government for over a century. It was first regulated by local governments.¹ Gas was manufactured locally from coal and distributed within metropolitan areas of the industrialized

¹The discussion in this section draws on material from Congressional Quarterly Inc., Energy Policy, 2d ed. (Washington, D.C.: Congressional Quarterly, Inc., 1981), pp. 46-51; Edmund W. Kitch, "Regulation of the Field Market for Natural Gas by the Federal Power Commission," Journal of Law and Economics 11 (October 1968): 248-254; William E. Mosher and Finla G. Crawford, Public Utility Regulation (New York: Harper & Brothers Publishers, 1933), pp. 402-404; Richard J. Pierce, Jr., Natural Gas Regulation Handbook (New York: Executive Enterprises

northeastern and north central regions of the country. The cities sought to regulate these local production and distribution systems by granting franchises for their operation.

In the late 1800s, two important gas-related developments took place. First, as gas distribution systems grew beyond the boundaries of metropolitan areas, state governments became involved in regulation, thus beginning a new phase of government regulation. As these early distribution systems were located, for the most part, in individual states, federal regulation was not seriously considered. Second, natural gas from underground reservoirs began to supplement and then replace manufactured gas.

State governments regulated gas production in addition to gas distribution systems. In the late nineteenth and early twentieth centuries, oil and gas conservation legislation was passed in producing states. For example in 1878, the Pennsylvania legislature passed a law requiring the plugging and casing of wells in order to prevent gas from escaping. New York passed a similar law in 1879 and other producing states followed. Regulation of gas production in some states resulted from a need to preserve the pressure in oil reservoirs, which was provided by natural gas and which was necessary to produce oil.

Publications Co., Inc., 1980), pp. 15-17; M. Elizabeth Sanders, The Regulation of Natural Gas: Policy and Politics, 1938-1978 (Philadelphia: Temple University Press, 1981), pp. 26-28; Walter L. Summers, "The Modern Theory and Practical Application of Statutes for the Conservation of Oil and Gas," in Section of Mineral Law of the American Bar Association, Legal History of Conservation of Oil and Gas (Baltimore: The Lord Baltimore Press, 1939), p. 1; U.S. Congress, House, Subcommittee on Fossil and Synthetic Fuels of the Committee on Energy and Commerce, Natural Gas Regulation Study, prepared by the Congressional Research Service and The National Regulatory Research Institute, Committee Print 97-GG (Washington, D.C.: Government Printing Office, 1982), pp. 56-59, 195; and U.S. Congress, Senate, Report of the Federal Trade Commission, S. Doc. 92, 70th Cong., 1st sess., 1936, pt. 84-A, p. 611.

Initially, state legislatures undertook direct regulation by legislation. Later, state regulation of the gas industry was accomplished by specialty commissions with industry cost expertise. Massachusetts was the first state to establish a commission to regulate the gas industry: the Board of Gas Commissioners was formed in 1885 to supervise companies engaged in the manufacture of gas for fuel and lighting. In 1907, New York and Wisconsin began regulation of gas companies and other public services through public service commissions. Other states followed their lead, and by the end of World War I most states had public service commissions charged with insuring adequate service at a fair price for customers of gas and other utilities. Many states established separate commissions to regulate the production of gas (and oil) and the transmission and distribution of gas (and electricity).

State regulation did not go uncontested. Challenges to state attempts to regulate often came in the form of a court case. For example, in 1911, the U.S. Supreme Court decided a case involving an attempt by Oklahoma to prevent the sale of any of its gas outside that state. Gas had been discovered in the oil fields of both Oklahoma and east Kansas, and in the early 1900s a network of local pipelines was built. Because it was thought at the time that the gas supply was limited, the Oklahoma legislature approved a prohibition on the export of gas from the state. This law, however, was declared unconstitutional by the Supreme Court.²

The Appalachian region of the country became a major producer of natural gas at this time. Production was centered in West Virginia with the most important customers located in Pittsburgh and Cleveland. Production peaked at 519,303 million cubic feet in 1917 and declined thereafter. It stabilized by 1925 at about 330,000 million cubic feet.

²Oklahoma v. Kansas Natural Gas Company, 221 U.S. 229 (1911).

This decline in gas production had some consequences for state regulation of the gas industry, and provided the setting for another challenge to a state's regulation of the gas industry. Because production decreased but demand was constant, shortages resulted. In addition, while state public utility commissions were able to regulate the intrastate gas market and hold prices down, the interstate market was unregulated at this time and brought higher prices for producers. Consequently, producers in West Virginia diverted gas to the interstate market. This practice, in conjunction with the shortages due to the overall decline in production, caused an increased scarcity in that state.

The West Virginia legislature responded to this situation by enacting legislation in 1918 that required the state's gas producers to meet the needs of their customers in West Virginia before selling gas in the interstate market. Ohio and Pennsylvania challenged the statute's constitutionality, and in 1923 the U.S. Supreme Court struck down the law as a violation of the interstate commerce clause of the U.S. Constitution.³

In addition to shortages, the decline in gas production after 1917 caused sharp increases in prices to consumers in the Appalachian states. Regulators in these states could do very little about the increasing prices of gas coming into their states and allowed local distribution companies to pass the increased costs on to their customers. When further rate increases could no longer ensure a sufficient profit, distributors abandoned their facilities. The utility regulators were sometimes able to prevent such abandonment, but, as discussed below, consuming states were not entirely successful in their attempts to regulate the rate charged by interstate pipelines to distributors in those states.

³Pennsylvania v. West Virginia, 262 U.S. 553 (1923).

In the 1920s, improvements in pipeline construction made possible the transportation of gas over long distances from the oil and gas producing regions of the southwest. As demand for gas grew, distributors began to build pipelines to connect their distribution systems, located in one state, with gas producers in other states. In addition, independent pipeline companies formed to buy gas in one state, transport it, and resell it in other states. By the 1930s, many cities outside gas producing areas were using natural gas.

Investors, attracted by the increasing profitability of supplying natural gas to urban areas, began to buy controlling shares of stock in numerous companies. These investors were able to build large holding companies which often controlled vertically integrated gas and electric systems operating in several states. A Federal Trade Commission (FTC) report on public utility corporations, issued in ninety-six volumes from 1928 to 1937, found that in 1934 eight holding companies controlled about one-fourth of the country's gas supply. But the study also found that these same companies controlled about four-fifths of the gas sold and transported on the interstate market.

The interstate pipelines, like the distribution companies, were considered natural monopolies. Often, only one pipeline connected a distributor to the gas producers so that if this pipeline charged an excessive price for gas, there were no competitors to which the distributor could turn. A pipeline could also pay a producer very low prices, taking advantage of the fact that it was often the sole buyer of the producer's gas. This created the threat of excess middlemen profits.

The states attempted to oppose these practices of the interstate pipelines through their regulatory powers. Regulators in some producing states set minimum prices for sales of gas by producers to pipelines, and many consuming states attempted to regulate the prices that the pipelines were charging the distributors and their other customers.

State efforts to regulate the gas industry raised questions about the scope of state powers, and as noted before, resulted in judicial challenges to those regulations. The Supreme Court upheld the right of a state to promote gas conservation, holding in 1900 that an Indiana statute prohibiting the escape of gas into the air was constitutional.⁴ The issue raised in many cases, however, was whether the state regulation in question would interfere with the flow of interstate commerce. In different instances, the courts provided different answers to that question. In the Oklahoma and West Virginia cases, the Supreme Court struck down statutes attempting to withhold gas from interstate commerce. The Court also struck down a state attempt to tax gas flowing in the interstate market. In a 1919 decision, however, the Court upheld the power of a state (Kansas) to set rates in that state for gas that had come from another state (Oklahoma). The majority stated that interstate commerce had ceased when the gas had entered Kansas pipelines. But, in 1924 the Court decided that a state could not regulate the rates charged by an interstate pipeline to a local distribution company because that transaction was part of interstate commerce and could not be regulated by the states. The states were not allowed to regulate the sale, transportation, or delivery of natural gas in interstate commerce despite the absence of any federal regulation.⁵ Thus, the Commerce Clause of the Constitution, as interpreted by the Supreme Court, became a major obstacle to state regulation of the natural gas industry.

⁴Ohio Oil Company v. Indiana, 177 U.S. 190 (1900).

⁵United Fuel Gas Co. v. Hallanan, 257 U.S. 277 (1921); P.U.C. v. Landon, 249 U.S. 236 (1919); Missouri v. Kansas Natural Gas Company, 265 U.S. 298 (1924).

The court rulings discussed above placed restrictions on the ability of the states to regulate the interstate aspects of the natural gas industry. At the same time, the industry was becoming an increasingly interstate industry. The result was a regulatory gap which was to be filled by the federal government.

The Natural Gas Act of 1938 and Subsequent Events

Because the states could not act, the Congress responded to the complaints of the cities, gas-consuming states, and local distribution companies by passing the Natural Gas Act of 1938. It gave the Federal Power Commission (FPC) the authority to regulate the interstate transmission of natural gas. The Act resulted from several years of debate and compromise. The variety of interest groups at the time of the debate and passage of the NGA and the divisions among these interests are quite similar to those found today.

Legislative History of the NGA

The Federal Trade Commission suggested a number of reforms based upon the findings of its previously mentioned investigation into public utility corporations. It suggested that the federal government examine the holding companies and force divestitures and reorganizations when needed. The Commission also recommended federal regulation of interstate pipelines, noting that state efforts were "at best indirect, partial, and poorly founded because of their limited authority to ascertain facts and their lack of authority to regulate interstate commerce." Federal regulation of interstate commerce would supplement state regulation of the intrastate gas market and would neither duplicate nor supersede state regulation. The FTC's recommendation regarding interstate pipelines was the following.

A federal law should be enacted applicable to interstate natural gas pipelines which transport gas for ultimate sale to and use by the public, regulating contracts for purchase of gas to be transported interstate, or regulating rates for carriage or city-gate rates at the carriage or city gate rates at the end of such transportation, or all of these . . . Retail rates for gas transported and delivered in interstate commerce, if federally regulated at all, should be regulated only when they are not regulated by the State in which the gas is distributed to the public.

The FTC noted that independent gas producers were "at the mercy" of the pipeline companies serving their fields. The report stated that:

Independent well owners, producers, or leaseholders should be assured the opportunity to sell gas under equitable, ratable taking at fair prices or to have it transported by pipe line [sic] at reasonable nondiscriminatory contract rates and delivered at a reasonable price at the city gateways without intermediate intersystem profits.

The Commission recommended the enactment of state legislation incorporating these last proposals with a federal law prohibiting the marketing of gas, which violated the rules, in interstate commerce.⁶

The FTC report led to the introduction of legislation embodying some of the Commission's recommendations.⁷ An omnibus bill, the

⁶See U.S. Congress, Senate, Report of the Federal Trade Commission, pt. 84-A, pp. 608, 609, 616-617.

⁷This discussion of the legislative history of the NGA draws on Note, Legislative History of the Natural Gas Act, 44 Geo L.J. 695 (1956); Sanders, op. cit., pp. 34-42, 48-49; U.S. Congress, House, Committee on Interstate and Foreign Commerce, Public Utility Holding Companies, Hearings before the House Committee on Interstate and Foreign Commerce on H.R. 5423, Part 1. 74th Cong., 1st sess., 1935, pp. 43-54; U.S. Congress, House, Committee on Interstate and Foreign Commerce, Natural Gas, Hearing before a Subcommittee of the House Committee on Interstate and Foreign Commerce on H.R. 11662. 74th Cong., 2nd sess., 1936, pp. 1-9; U.S. Congress, House, Natural Gas, H.R. Rept. 2651 to Accompany H.R. 12680, 74th Cong., 2nd sess., 1936,

Public Utility Act of 1935, incorporated several approaches to utility regulation. It mandated the abolition of all holding companies within a five year period. In addition, it sought to extend federal utility regulation to the interstate sale of gas. The legislation required a certificate of public "convenience and necessity" for the transmission of gas from a field and conferred common carrier status upon pipelines. Interstate pipelines were to charge only "reasonable" rates.

The holding company title of the bill generated great controversy, although it was ultimately modified and enacted into law as the Public Utility Holding Company Act of 1935. The mandatory abolition was deleted from the final version, but the Securities and Exchange Commission was authorized to recommend "simplification" in holding company structures. The companies themselves were to demonstrate to the Commission that "substantial economies" could result from retaining the holding company structure. The result of these provisions was the demise of the holding company as an important power in the natural gas industry. By 1950 holding companies controlled only 18% of the interstate gas pipeline.

Title III of the Public Utility Act of 1935 contained the natural gas provisions. The provisions were to apply to "the transmission and sale of natural gas in interstate commerce, but shall not apply to the retail sale of natural gas in local distribution." No mention was made of production in specifying proposed federal jurisdiction.

pp. 1-8; U.S. Congress, House, Committee on Interstate and Foreign Commerce, Natural Gas, Hearing before the House Committee on Interstate and Foreign Commerce on H.R. 4008, 75th Cong., 1st sess., 1937, pp. 1-20; and U.S. Congress, House, Interstate Transportation and Sale of Natural Gas, H.R. Rept. 709 to Accompany H.R. 6586, 75th Cong., 1st sess., 1937, pp. 1-10.

This legislation required a pipeline to obtain a certificate of public convenience and necessity from the FTC before constructing or extending its facilities in order to transmit gas from a natural gas field already served by another pipeline. Pipelines were to charge only "just and reasonable" rates, and any rate found not to be just and reasonable would be declared unlawful. Title III of the Public Utility Act also contained a section that would have conferred common carrier status upon pipelines.

The natural gas provisions of the omnibus bill, drawn up mainly by the FPC with assistance from the FTC and House Interstate and Foreign Commerce Committee Chairman Sam Rayburn (D-Texas), were not reported to the House floor by Rayburn's committee. While independent gas producers would have benefitted from the proposal, particularly the common carrier provision, they were not able alone to overcome the opposition of the interstate pipelines to ensure the bill's passage. The pipelines objected to four of the major gas provisions: the common carrier status; the requirement for an FTC certificate of public "convenience and necessity," which the interstate pipelines charged put them at a disadvantage with respect to the intrastate pipelines that were not required to obtain this certification; the regulation of the sale of gas for resale by local utilities to industry, which the pipelines wanted to remain unregulated; and the bill's standards for determining the costs of transporting gas.⁸

⁸Section 312 of the 1935 bill incorporated a "prudent investment" standard for cost determination and rate setting. A commission would start with the original cost of the utility's property and then ignore "unwise" or excessive expenditures to arrive at a "prudent investment" figure. This figure could then be used in determining the rate which the utility would be allowed to charge. The Natural Gas Act omitted this standard, helping to ensure pipeline support for the bill. Section 6 of the NGA directed the Federal Power Commission to use the "actual legitimate cost" of the property used to provide services instead of the "actual legitimate prudent cost" which the 1935 legislation had required. See Sanders, *op. cit.*, pp. 78-79.

In 1936, a new bill concerned solely with natural gas was introduced, and the House committee held hearings. After the hearings were concluded, a revised bill was introduced and reported to the House. This bill would not have regulated sales for resale to industry. The certification requirement of the 1935 bill was deleted, and the section on cost determination was revised, dropping the "prudent cost" standard. In addition, the provisions on extension of facilities were substantially revised. The FPC could order a pipeline to extend or improve its facilities and sell gas to a distributor if the Commission decided such action was in the public interest. However, the FPC could not compel a pipeline to take such action when to do so would impair the pipeline's ability to serve its existing customers adequately or would require the pipeline to enlarge its facilities. The Interstate and Foreign Commerce Committee's report to the House recommended passage of the legislation, but the bill died.

In 1937, the natural gas legislation was reintroduced. This bill was almost identical to the revised 1936 bill. This bill incorporated a requirement for an FPC certificate whenever an interstate pipeline wanted to construct or extend facilities in order to sell gas in a market already being served by another interstate pipeline. Because this section guaranteed some protection against competition and because it contained modifications to meet their major objections, the interstate pipelines eased their opposition to federal regulation. The bill passed the House Interstate and Foreign Commerce Committee unanimously in April 1937, subsequently passed the House and Senate with only minor amendments added, and was signed into law in June 1938 as the Natural Gas Act of 1938.

It is important to note that none of these bills was intended to extend federal jurisdiction over gas production. The 1935 bill did not list production among the phases of the natural gas industry to be regulated. Subsequent bills, including the NGA, specifically exempted production. As will be seen, however, decisions by the FPC and the

U.S. Supreme Court expanded the scope of the NGA and FPC jurisdiction to include both affiliated and independent producers.

The Provisions of the NGA

In its original version, the Natural Gas Act of 1938 met the major objections of the interstate pipelines, reducing their opposition to some federal regulation. The NGA contained no common carrier provisions; it adjusted the public convenience and necessity certification requirement so that such certification was necessary in order for a pipeline to enter a market already served by another pipeline, instead of being required before a pipeline could transmit gas from a field already served by another pipeline; and, (until the 1962 amendment) the NGA exempted sales for resale to industry from its rate suspension provisions. The law also met objections that the pipelines had had concerning cost determination.⁹

Certain sections of the Natural Gas Act are important for both an understanding of subsequent events and an understanding of the current law concerning federal regulation of gas. Section 1 of the NGA specifies the limits of federal regulation of gas. It states that:

The provisions of this act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas [sic] companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.¹⁰

⁹See Sanders, *op. cit.*, pp. 48-49 and the discussion of the different cost determination standards in footnote 8.

¹⁰U.S., Federal Power Commission, Natural Gas Act (Washington, D.C.: Government Printing Office, 1939), p. 1. Sections 4 and 5 discussed below are on pp. 3-5.

Thus, the NGA provisions are limited to natural gas in interstate commerce. The NGA excludes from its provisions any natural gas that is not in interstate commerce, and hence is in intrastate commerce. The provisions of the NGA neither apply to the local distribution of natural gas nor to the production or gathering of natural gas. Section 1 of the NGA was subjected to subsequent United States Supreme Court decisions, which had the effect of gradually expanding the jurisdiction of the FPC to regulate sales of natural gas.

Sections 4 and 5 of the NGA are important because, while the Natural Gas Policy Act of 1978 (NGPA) has created an overlay of legislation concerning federal gas regulation, these provisions of the NGA are still in effect. Section 4 of the NGA is concerned with the rates charged by a natural gas company. The provision states that all rates and charges are to be "just and reasonable" and that any rate found not to be so would be declared invalid. At rate hearings, the burden is on the pipeline to show that the proposed increase is just and reasonable. In addition, section 5 provides that no natural gas company will make or grant any undue preference or advantage to any person. Nor will a pipeline subject any person to any undue prejudice or disadvantage.

Section 5 of the NGA empowers the Federal Power Commission, upon determining that a rate is unjust or unreasonable, to determine the just and reasonable rate itself. The FPC can also, upon finding that any rule, regulation, practice, or contract affecting a rate, charge, or rate classification is unjust, unreasonable, unduly discriminatory, or preferential, determine what the just and reasonable rule, regulation, practice, or contract is and can order it into force. This provision has been cited as a statutory source that could empower the FERC, the successor agency of the FPC, with the authority to rewrite imprudent contract provisions in producer-pipeline contracts.

As discussed above, the NGA limited initial federal regulation to the interstate pipelines. Subsequent events, particularly three Supreme Court decisions, expanded the scope of federal regulation and created major controversies.

Supreme Court Decisions on the NGA

In the years following the passage of the NGA, the FPC began to deal with the issue of what it could or should do with respect to producer sales of gas to interstate pipelines. In 1940, a majority of the FPC ruled that the Commission had no jurisdiction over the sale of gas by independent producers to the interstate pipelines. Section 1 of the NGA had exempted the "production or gathering" of gas from federal jurisdiction, and the Commission concluded that the producers should not be subject to its jurisdiction because their sales in interstate commerce were "made as an incident to and immediately upon completion" of production and gathering and the producers were not otherwise subject to its jurisdiction. But the majority let it be known that its opinion might change after "further experience" with the Act.¹¹

In 1942, the FPC considered a consolidated case involving the issue of sales by a producer affiliated with an interstate pipeline to that pipeline. The Commission decided that because the pipelines were under its jurisdiction, it could also regulate the production facilities used for the interstate sales. The two companies involved in the case fought the Commission's ruling in court, citing the "production and gathering" exemption of the NGA as a basis for allowing them to charge a fair market price for the gas they produced.

¹¹See *In the Matter of Columbian Fuel Corporation*, 2 FPC 200,208 (1940).

In addition, again citing section 1, they argued that their production operations were exempt from regulation. The Supreme Court upheld the FPC in a 1945 ruling.¹²

In 1943, the FPC claimed the power to set rates for sales by a producer affiliated with an interstate pipeline to that pipeline and to two other pipelines. This claim was challenged by the producer involved.¹³ Interstate Natural Gas Company contended its sales to three different pipeline companies were not in interstate commerce, were part of production and gathering, and therefore, were exempt from FPC regulation. The FPC found that the sales to the three pipelines were in interstate commerce because the gas sold by Interstate Natural Gas Company to the three pipelines was in a constant flow from the wellhead, through the gathering lines owned by Interstate to the compressor station of each pipeline, and then through each compressor station into the pipeline and to the ultimate out-of-state consumer. Thus, because the sales were a part of the commerce carried on between two states, the sales were in interstate commerce even if they were consummated before the gas crossed a state line. The Supreme Court upheld the FPC holding. The Court also held that the sales were not exempt from FPC regulation under the "production or gathering" exemption of section 1(b) of the NGA. The Court held that the NGA reserved to the states the power to regulate the physical production and gathering of gas in the interest of conservation or of any other consideration of legitimate local concern. The Court held that asserting that the exercise of rate regulation may effect local interests was not sufficient to defeat FPC jurisdiction over sales for resale in interstate commerce.

¹²Colorado Interstate Gas Co. v. FPC, 324 U.S. 581 (1945). See Sanders, op. cit., p. 82 for discussion of this case.

¹³Interstate Natural Gas Co. v. FPC, 331 U.S. 682 (1947).

The Court's language in the Interstate Gas ruling concerning the FPC's jurisdiction under the NGA was broad so that it raised the possibility that independent producers would also come under federal regulation. The FPC, as noted earlier, had expressed a somewhat qualified view in 1940 that it had no such jurisdiction. In two cases that the Commission considered in 1947, the FPC declared that it had no authority over sales at the end of gathering. In addition, the FPC issued an opinion several weeks after the Interstate Gas ruling urging the passage of legislation exempting independent producers from the provisions of the NGA and stating the Commission's view that "it was the intent of the Congress that the control of production or gathering of natural gas should remain a function of the states and that the Natural Gas Act should not provide for regulation of those subjects."¹⁴

Despite these actions and statements by the FPC, the independent producers sought further assurance that they would not soon be regulated. They began to lobby Congress for the passage of a bill to curb the FPC's authority. Such a bill passed the House in 1949 and the Senate (by only 6 votes) in 1950. However, President Truman, who had appointed supporters of regulation to the FPC, vetoed the bill.

The most important Supreme Court decision came in the case of Phillips Petroleum Company v. Wisconsin.¹⁵ This case originated with a petition by the Wisconsin Public Service Commission and the Detroit City Council to the FPC, requesting the FPC to regulate the gas sales of Phillips. Phillips was an independent producer, producing and processing gas, but not owning its own interstate pipelines, selling instead to unaffiliated pipelines.

¹⁴See *In the Matter of Fin-Ker Oil and Gas Production Company*, 6 FPC 92,95-96 (1947); *In the Matter of Tennessee Gas and Transmission Company and the Chicago Corporation*, 6 FPC 98,103-104 (1947) and FPC Order No. 139, 12 Fed. Reg. 5585-86 (1947).

¹⁵*Phillips Petroleum Company v. Wisconsin*, 347 U.S. 672 (1954).

The issue in the case revolved around the question of whether Phillips was a natural gas company as defined by the NGA and thus subject to regulation by the FPC. The NGA had defined a natural gas company as an individual or corporation engaged in the transportation or sale of gas in interstate commerce. The Act, as noted earlier, had applied only to interstate commerce and had exempted other sales and transportation as well as the production and gathering of gas. Phillips argued before the FPC that its sales took place at the end of the production and gathering process (i.e., that they were a part of that process) and were thus exempt from federal price regulation. The FPC agreed with Phillips, concluding that the company was not a natural gas company, as defined by the NGA.

The Wisconsin Public Service Commission challenged the FPC decision in court. The U.S. Court of Appeals for the District of Columbia overruled the FPC, concluding that Phillips' sales of gas to pipelines were not a part of production and gathering, but rather occurred after that process. The case then went to the Supreme Court, which upheld the D.C. Court's reversal of the Commission's original decision. The Court held that Phillips was a natural gas company as defined by the NGA and that its wellhead price for sales to pipelines was subject to federal rate regulation. The Supreme Court also agreed with the D.C. court that Phillips' sales occurred after the production and gathering process had ended. The Court stated that "we believe that the legislative history indicates a Congressional intent to give the Commission jurisdiction over the rates of all wholesale [sales] of natural gas in interstate commerce, whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company." Consequently, independent producers who sold to an interstate pipeline were to be regulated by the FPC. The Court held that regulation of sales for resale in interstate commerce by an independent producer was no different from regulation of sales for resale by a producer affiliated with a pipeline.¹⁶

¹⁶See the Phillips opinion, 347 U.S. 672,678,681-682,685.

The Phillips decision, like the Interstate Gas decision, provoked the independent producers to lobby the Congress for legislation exempting them from FPC jurisdiction. In July 1955, the House passed such a bill by a vote of 209-203. The bill passed the Senate in 1956 by a fifteen vote margin, but, just before the vote, a Republican Senator announced his intention to vote against the bill because an oil company lawyer, who sought the passage of the legislation, had offered the Senator a \$2500 campaign contribution. President Eisenhower, who had supported the legislation, vetoed it because of the incident. Further attempts to amend the NGA at that time were unsuccessful.¹⁷

With the Phillips decision, a new phase in government regulation of the gas industry began. In the phase just ended, the Congress had passed the NGA because the states were not able to regulate the interstate natural gas industry effectively. This Act did not prevent the issue of the role of government in the gas industry from reappearing. Various interest groups sought to have their views adopted as official policy. Those who sought more federal regulation were able to persuade the Supreme Court of their views, while those in favor of more limited federal regulation won Congressional approval of legislation incorporating their views, but were thwarted by two presidential vetoes.

The FPC, in implementing the Phillips decision, first treated each producer as an individual public utility, attempting to work out a fair rate of return for each. The Commission used this approach from 1954 to 1960. By the end of this period, the backlog of rate cases had grown enormously. The Commission had processed only ten

¹⁷See Congressional Quarterly Inc., op. cit., p. 47.

individual cases out of several thousand, and one report estimated that the backlog could not be eliminated for almost a century.¹⁸

In 1960, the FPC switched to an area rate pricing system. The Commission identified twenty-three gas producing regions in nine states and froze rates at 1959-60 levels in these areas by setting two prices for each area. The first was "a price applicable to new contracts above which we will not certificate new sales without justification of the price." The second was "a price pertaining to existing contracts above which we shall suspend price escalations." These price ceilings were to be in effect only until the Commission could hold hearings and determine "just and reasonable" rates for each region based on the average costs of production in each area. The Commission's stated objectives were to set prices in all producing areas that were adequate to maintain the gas supplies needed by the

¹⁸The FPC discussed the problem in a 1960 opinion as follows:

An illustration of the administrative impossibility of separate determinations for all producers' rates is found in the fact that there are 3,372 independent producers with rates on file with this Commission. The producers have on file with us 11,091 rate schedules and 33,231 supplements to these schedules. Currently, 570 of these producers are involved in 3,278 producer rate increase filings now under suspension and awaiting hearings and decisions. The number of completions of independent producer rate cases per man-year during the first 6 years following the Phillips decision indicate that nearly 13 years would be required for our present staff to dispose of the 2,313 cases pending on July 1, 1960. Within this 13-year period an additional estimated 6,500 cases would have been received.

The FPC noted that if its staff were to be immediately tripled, "we would not reach a current status in our independent producer rate work until 2043 A.D.--eighty-two and one-half years from now." 24 FPC 537,545-546 (1960).

consumers of the nation, but that were no higher than necessary to accomplish this purpose.¹⁹

Setting rates for a producing region proved to be a lengthy process. The first area rates were set for the Permian Basin area of southeast New Mexico and west Texas. The FPC issued its initial order announcing the rate hearing in December 1960. The hearings lasted four and one-half years, and the Commission did not issue its opinion until August 1965. A court challenge ensued, and it was not until 1968 that the issue was decided with a Supreme Court ruling upholding the constitutionality of the process.²⁰

Gas Shortages and the Winter of 1976-77

The area rate system of regulation, however, depressed gas production levels.²¹ The interim price ceilings imposed at the beginning of the process discouraged producers from drilling for gas expected to cost more than the historical average prices upon which the interim ceilings were based. Because the rate setting process

¹⁹See FPC Opinion No. 338, 24 FPC 537,547 (1960); FPC Statement of General Policy No. 61-1, 24 FPC 818,820 (1960); and FPC Order Instituting Area Rate Hearings, 24 FPC 1121 (1960).

²⁰Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

²¹The discussion in this section draws on material from Stephen G. Breyer and Paul W. MacAvoy, "Regulating Natural Gas Producers," in Energy Supply and Government Policy, eds. Robert J. Kalter and William A. Vogely (Ithaca, N.Y.: Cornell University Press, 1976), pp. 162-165; Congressional Quarterly Inc., Congressional Quarterly Almanac 1977 (Washington D.C.: Congressional Quarterly Inc., 1977), pp. 646-647; Congressional Quarterly Inc., Energy Policy, pp. 48-49; Clark A. Hawkins, The Field Price Regulation of Natural Gas (Tallahassee: Florida State University Press, 1969), pp. 77-86; Robert B. Helms, Natural Gas Regulation: An Evaluation of FPC Price Controls (Washington, D.C.: American Enterprise Institute for Public Policy Research, 1974), pp. 22-24; Kitch, op. cit., pp. 264-265; and Pierce, op. cit., pp. 21-25.

took several years to first be initiated by the FPC and then be upheld in the courts, the prices producers could charge were held at the 1959-60 levels through much of the 1960s.

The Commission collected cost data for the period in which producers were deterred from drilling for the higher priced gas and used an average of these costs as the basis for the rate it set for each area. As low cost drilling sites were exhausted, the marginal cost of production of new supplies rose far above the average, historical production cost of flowing gas. Drilling declined with the increasing difference between marginal cost and price based on average cost. Gas producers complained of prices being too low under FPC regulation of the interstate market.

However, intrastate sales were not regulated by the FPC and brought higher prices for the producers. Intrastate sales were sales of gas from a producer to a pipeline that did not carry gas across state lines or sales to another customer in the same state as the producing well. A result of this price difference was that the interstate market was hit harder by the declining gas reserves of the 1960s and 1970s because the intrastate market with its higher prices was more attractive to gas producers.

At the same time that gas reserves were declining, overall demand for gas--especially demand in the interstate market--was rising. The FPC attempted to respond to this situation in 1972 by adopting a new pricing system that allowed some gas to be sold at a price above the normal regulated price. Drilling increased, but production again dropped in 1973. In June 1974, the Commission abolished the area-wide rate structure and substitute a national rate of 42 cents per thousand cubic feet (mcf) with an annual price increase of 1 cent per mcf for gas from wells that had been drilled after December 31, 1972, for gas not previously sold in interstate commerce, which was covered under contracts executed after December 31, 1972, and for gas covered under

contracts executed after December 31, 1972 where the sales were formerly made pursuant to contracts which expired after December 31, 1972. In December 1974, the FPC raised these rates to 50 cents per mcf, while retaining the annual escalation of 1 cent.²²

Others, including President Nixon, attempted to come up with a solution to the gas shortage. In November 1973, partially in response to the oil embargo, Nixon proposed an end to FPC control over the price of gas from new wells, gas recently dedicated to the interstate market, and gas from old wells once the contract governing its sale had expired. The U.S. Department of the Interior would be empowered to set price ceilings if there were a sharp increase in prices. The proposal, however, died in Congress.

In January 1975, President Ford proposed ending most price controls and adding a wellhead tax of 37 cents per mcf. Both measures were designed to curb demand for natural gas. The tax proposal was soon killed by the House Ways and Means Committee. The remainder of Ford's package also failed to receive a favorable Congressional response.

In that same session of Congress, the Senate approved a gas deregulation measure that had been offered as an amendment to an emergency natural gas bill. The amendment was introduced by Senators James B. Pearson (R-Kansas) and Lloyd Bentsen (D-Texas). The amendment was itself amended during consideration and in its final form deregulated new gas, but kept controls on the price of old gas even after the expiration of existing contracts. The House, however, passed a bill lifting controls only on the new gas produced by independent producers, defined as those with sales of less than 100

²²See FPC Opinion No. 699, 51 FPC 2212 (1974); and FPC Opinion No. 699-H, 52 FPC 1604 (1974).

billion cubic feet per year. The bill retained controls on the interstate sales of major producers and extended federal controls to their intrastate markets for the first time. Under this bill the FPC would have set a national average price for gas higher than under then existing regulations. No conference was held between the two houses to work out their differences, and the bills died.

In response to severe shortages, the FPC almost tripled the ceiling price on new gas in 1976, increasing it from 52 cents to \$1.42 per mcf for gas produced or contracted for after January 1, 1975. For gas placed on the interstate market in 1973 and 1974, the ceiling was 93 cents per mcf. By this time, the Commission, instead of relying solely on average historical costs, had shifted to using trended productivity data and trended drilling costs in setting rates.

Nevertheless, shortages continued to grow. By 1977, interstate pipelines could meet only 75% of their contractual requirements and many distributors curtailed deliveries to customers and imposed moratoriums on new or additional service.

The gas shortages in combination with the severe winter of 1976-77 demonstrated both the extent of the gas problem and the need for something to be done to rectify the situation. By February 1, 1977, eleven states had declared emergencies. Industries and schools were closing due to gas cutoffs. Over one million workers had been laid off and some residences faced temporary cutoffs of service.

President Carter, in office for less than two weeks, won speedy Congressional approval of an emergency bill to cope with the crisis. On February 2, Carter signed a bill that had moved through Congress in less than one week. The Emergency Natural Gas Act of 1977 allowed the President to declare a natural gas emergency if a severe gas shortage was endangering the supply needed for high-priority use.

High-priority use included residential use, use in a commercial establishment of less than 50 mcf on a peak day, and use necessary to sustain life and health or to maintain physical property. In addition, the law allowed the President up to April 30, 1977 to order any interstate or intrastate pipeline to carry emergency supplies of interstate gas to designated places, and it authorized the President to order pipelines to construct or operate any facilities necessary for such emergency transportation. The Act also authorized the President to allow interstate buyers to make emergency purchases of gas from intrastate markets at unregulated prices. This last grant of power to the President lasted only through July 31, 1977.

The Emergency Natural Gas Act of 1977 was designed to help people survive the winter crisis, but it did not provide an overall solution to the gas problem. Most members of Congress were not satisfied with it for that reason. A more comprehensive bill, however, was sent to the Congress by the Carter administration later in the year.

The Natural Gas Policy Act of 1978: Proposal, Debate, and Passage

Carter had directed his energy adviser, James R. Schlesinger, to formulate a comprehensive energy plan. The President gave this mandate to Schlesinger soon after taking office, imposing a 90-day deadline which the energy adviser and his group of about two dozen lawyers, economists, and administrators were able to meet. The result of this effort was the National Energy Plan, of which the natural gas policy legislation was a major and controversial part.²³ In this

²³The section on the NGPA uses material from Congressional Quarterly Inc., Congressional Quarterly Almanac 1977, pp. 708-717, 719-726, 735-738; Congressional Quarterly, Inc., Congressional Quarterly Almanac 1978 (Washington, D.C.: Congressional Quarterly, Inc., 1979), pp. 639-642, 647-663; Congressional Quarterly, Inc., Energy Policy, pp. 49-51; Pietro S. Nivola, "Energy Policy and the Congress: The Politics of the Natural Gas Policy Act of 1978," Public Policy 28 (Fall 1980): 494; Bob Rankin, "Conferees Fail to Reach Natural Gas Agreement," Congressional Quarterly Weekly Report 35 (December 1977): 2620; and Sanders, op. cit., pp. 169-171.

section, the evolution of the legislation is traced in order to show how the resulting law became so complex. The NGPA was a compromise between the opposing viewpoints of complete deregulation and continued regulation. The current controversy has, in large part, been shaped by this compromise.

Original Carter Proposals and House Action

The main natural gas provision of Carter's initial plan was federal regulation of the price of all new natural gas, both interstate and intrastate. The price of this gas would be tied to the price of domestic oil, expected to be about \$1.75 per mcf in 1978. Old gas would still be subject to existing price controls although such prices would rise to a ceiling of \$1.42 per mcf. The more expensive new gas was to be allotted to industrial customers while the cheaper gas would be for residential and commercial users. The plan defined "new" gas as that coming from new Outer Continental Shelf leases or as gas coming from wells tapping into any new onshore reservoir that were either 2.5 miles or more from the nearest well or at least 1,000 feet deeper than the deepest well within a 2.5 mile radius.

The entire energy package was introduced as a single bill in the House of Representatives on May 2, 1977. The various components were sent to five different committees, which faced a July 13 deadline set by Speaker Thomas P. O'Neill, Jr. for the completion of their work. The entire package was then to be reassembled and considered by a special House Ad Hoc Select Committee on Energy before being sent to the floor for deliberation by the entire House.

The natural gas provisions were referred to the Energy and Power Subcommittee of the House Interstate and Foreign Commerce Committee. The subcommittee set aside the Carter proposals and instead adopted a

gas deregulation plan sponsored by Representative Bob Krueger of Texas. Krueger's proposal would have deregulated the price of all new onshore gas discovered after April 20, 1977. It also deregulated the price of offshore gas over a five year period and would have imposed a ceiling on the price those in the interstate market could offer for intrastate gas as contracts expired. The subcommittee was reversed by the full committee, which approved the Carter plan on July 14, a day past O'Neill's deadline.

The energy package next went to the Ad Hoc Committee. This group included 40 members (27 Democrats, 13 Republicans) from the standing committees having jurisdiction over energy legislation. O'Neill selected Democrats who were likely to approve the President's program, and the select committee did just that. It passed the Carter natural gas bill, along with the rest of the energy plan, although it did adopt an amendment expanding the definition of new gas.

The amendment, designed to win support for Carter's program from those inclined to favor deregulation, broadened the classification to include gas from any new well drilled beyond the 2.5 mile requirement specified by the Carter plan, even if the well tapped into an existing reservoir. In addition, any gas from a newly discovered reservoir, even if within Carter's 2.5 mile limits would be classified as new. This amendment was subsequently approved by the whole House.

On August 5, the House passed the entire energy package, including the natural gas provisions as amended, by a vote of 244-177. In the process the House also turned back another effort by Krueger and some supporters to gain approval of deregulation of gas prices.

Senate Debate and Conference Deadlock

While President Carter was able to obtain much of what he wanted from the House, the same outcome was not to be in the Senate. The upper house split the program into six separate bills, including one containing the natural gas provisions of the program.

On September 13, the Senate Energy Committee deadlocked at 9-9 on a bill to deregulate the price of new gas within five years. Subsequently, the committee voted to send Carter's bill directly to the floor without any recommendations.

Ultimately, after thwarting the delaying tactics of James Abourezk (D-S.D.) and Howard Metzenbaum (D-Ohio), who argued for continued regulation, the Senate adopted a revised version of a substitute bill offered by Senators Pearson and Bentsen, whose proposal had been passed by the Senate in 1975. The bill, which was approved on October 4, deregulated the price of new onshore gas, imposing a ceiling of \$2.48 per mcf which would be in effect for two years after enactment of the legislation. New offshore gas would be deregulated at the end of five years. New gas was defined as gas first sold or delivered in interstate commerce after January 1, 1977. In addition, this bill required the allocation of old, lower priced gas to high priority customers, including residences, schools and hospitals, until the price of new gas to other customers equalled the price of substitute fuel.

The entire energy package was next sent to a conference committee of the houses of Congress, where the conferees became deadlocked on the natural gas issues. The House members of the conference continued to support the position adopted by their chamber while the Senate conferees, who were the members of the Senate Energy Committee, were split evenly on the issue of deregulation. The stalemate continued for the remainder of 1977 and early 1978.

On March 7, 1978, after several weeks of closed door sessions, nine of the Senate conferees announced agreement on a compromise. The terms of the compromise included deregulation of new gas by January 1, 1985, although Congress or the President would be allowed to reimpose price controls for two years at any time after June 30, 1985 if gas prices rose too sharply. The proposal also stipulated a controlled rise in gas prices before decontrol in 1985. At the beginning, the price of new gas would be set at \$1.75 per mcf and would then rise at a rate equal to the consumer price index plus 3.5 percent through April 20, 1981 and plus 4 percent from then through 1984.

The plan defined new onshore gas as that coming either from new wells located at least 2.5 miles from an old well or from new wells that were at least 1,000 feet deeper than any well located within the 2.5 mile limit. This definition also included gas coming from a reservoir that was not in commercial production before April 20, 1977. New offshore gas was defined as gas produced from an offshore lease commissioned since April 20, 1977 or gas from a reservoir discovered since July 27, 1976.

The compromise would have immediately deregulated certain types of gas that were especially costly to produce. This included gas from Devonian shale, from geopressurized brine, from new wells drilled below 15,000 feet, and occluded gas from coal seams.

At a public session on March 22, 1978, the Senate conferees voted 10-7 to offer their compromise to the House. The House conferees voted 13-12 to accept the compromise, but with changes. The House plan would have defined new gas more narrowly and would have instituted a system of incremental pricing requiring industrial customers to initially bear a disproportionate burden of paying for new high priced gas. The House would have tied its inflation adjuster to the implicit gross national product deflator instead of the consumer price index. The House would also have deregulated prices six months later than the Senate.

Although differences remained, the plans showed that the two houses were closer than they had been up to that point. One important development was that for the first time, a majority (13 of 25) of the House conferees had supported deregulation of new gas prices.

Final Compromise and Passage

On April 21, 1978 an agreement was announced between about a dozen of the leading House and Senate conferees who had been meeting in closed door sessions. It was this compromise that was to become the Natural Gas Policy Act. The compromise, which among its provisions called for decontrol of new gas on January 1, 1985, was attacked by those who wanted immediate deregulation and by those who wanted continued controls. It was not until May 23 and 24 that a majority of House and Senate conferees, respectively, was found to support the compromise.

The bill was then drafted by the legislative staff. As some conferees saw the written provisions, they withdrew support. Finally, however, with some help from President Carter, who had moved from opposing deregulation in 1977 to supporting it in 1978, a majority of conferees was persuaded to sign the report of the conference committee on August 18.

As the gas bill went to the floors of both chambers, its passage was not assured. However, White House lobbying helped to build support in the Senate which defeated two recommittal motions and adopted the conference report on September 27 by a vote of 57-42. In the House, Speaker O'Neill worked to secure passage of the entire energy package, which was voted on as one bill known as the National Energy Act. On October 13, the House voted 207-206 to keep the package intact, thus helping to shield the natural gas provision by linking it to other, more popular parts of the plan. On October 15,

the House passed the National Energy Act by a vote of 231-168. This action came almost eighteen months after President Carter had made his original proposals.

The National Energy Act was composed of five separate pieces of legislation. One of these, the Natural Gas Policy Act of 1978, is important for this study. Its provisions are presented in some detail in appendix C.

Current State Regulation

Although the role of the federal government in natural gas regulation has overshadowed that of the states, particularly since the Phillips decision, over the years the states have retained important regulatory functions in this area. With the federal deregulation mandated by the NGPA and possible coming changes in the NGPA, the latitude allowed for state regulation of the industry might increase or decrease. An overview of the current state regulatory role is presented here. A detailed discussion of the scope of state authority can be found in another NRRI report.²⁴

State regulation encompasses the production, transportation, and distribution phases of the gas industry. Distribution is the phase in which the states are most actively involved in regulation. Each state is free to establish and conduct such regulation in a manner which it feels is best for that state, thus causing some lack of uniformity among the states in terms of particular regulations adopted. Generally, however, state commissions regulate the retail rates charged by distributors within their states, while ensuring that the distributors provide adequate service to their customers. The state commissions may initiate rate investigations and set temporary rates

²⁴See Natural Gas Regulation Study, op. cit., pp. 67-73, 193-297.

if such action is thought to be needed. State commissions may also suspend proposed rate filings. Distributors must obtain approval from the state public utility commission before abandoning service.

In the transmission phase of the industry, a state has the authority to regulate pipelines that operate solely within its boundaries. As in the case of federal regulation of interstate pipelines, state regulation of intrastate pipelines is usually cost based.

As noted in the first section of this appendix, state regulation of production for conservation purposes was approved by the U.S. Supreme Court. However, when state regulation of production was thought to interfere with interstate commerce, as in the cases of the Oklahoma and West Virginia statutes, such regulation was declared unconstitutional.

At present, gas producing states continue to be active in regulating various aspects of the production process. Such power, however, is usually vested in agencies other than the public utility commissions, such as a department of natural resources or an oil and gas conservation commission. These state agencies may regulate the volume and rate of production, the spacing of wells, and the rates for wellhead contracts. However, states differ according to which of these regulatory powers are permitted to the production regulating agencies.

The states have also had to deal with legal disputes between owners of adjacent property over the oil and gas beneath the surface of their land. Thus, in regulating gas production, the states have had to take the rights of these property owners into account and attempt to determine the legitimacy of their claims. State commissions also enforce safety standards for gas transmission and

distribution and approve the extension of service to new customers. Many commissions also have the authority to permit or to require interconnections among gas utilities in order to ensure adequate service for the customers of those utilities.

Many commissions require a gas utility to obtain a certificate of convenience and necessity before undertaking any major new construction project. Such projects would include gas generating plant, transmission lines, distribution lines, or other plant.

State public utility commissions may also have the authority to approve the issuance of major securities by gas utilities. Such securities would include mortgage bonds, debentures (general obligation bonds not secured by any claim or specific assets), preferred stock, notes over one year, and sometimes notes under one year. Various states also require commission approval for major corporate transactions including sale or purchase of facilities, merger, consolidation, or the purchase of another utility's securities.

In sum, over the past century state agencies have received the authority to regulate many parts of the gas industry. A legitimate concern of these agencies is the limitation of their authorities that may be contained in the NGPA or any successor legislation to the NGPA.

APPENDIX C

THE NATURAL GAS POLICY ACT OF 1978

The Natural Gas Policy Act of 1978 (NGPA) is one of five major parts of the National Energy Act. It represented a compromise between those who wanted immediate deregulation of gas producers and those who wanted Natural Gas Act (NGA) regulation extended to all producers. Enacted during the Carter administration on November 9, 1978, the NGPA was formulated in 1977 following severe shortages of natural gas supply and was designed to provide incentives for the exploration and production of new natural gas and the elimination of the interstate/intrastate division in the regulation of natural gas producer sales. Chapter 2 of this report contains an overview of the NGPA. The detailed features of this Act that are important for this study are presented here.

The NGPA is divided into six titles: Title I - Wellhead Pricing; Title II - Incremental Pricing; Title III - Additional Authorities and Requirements; Title IV - Natural Gas Curtailment Policies; Title V - Administration, Enforcement, and Review; and Title VI - Coordination with the Natural Gas Act and the NGPA's Effect on State Laws. Titles I and II are discussed here in some detail, and the remainder of the Act is discussed briefly. A summary of how the NGPA has been implemented then follows.

Title I - Wellhead Pricing

Title I of the NGPA pertains to the regulation of wellhead prices, which are, of course, the natural gas prices that are charged by the producer to its customer, typically, a pipeline company. This title contains two parts: subtitle A deals with wellhead price controls for specific categories of natural gas, and subtitle B deals with the timetable for decontrol of certain natural gas wellhead prices.

Subtitle A - Wellhead Price Controls

Subtitle A contains ten sections, 101 through 110. Price ceiling rules for "first sales" of natural gas, including inflation adjustment factors that apply to the various categories of gas, are contained in section 101. According to the NGPA, a first sale of natural gas is a sale by a gas producer to any purchaser, which precedes any other such sale. The purchaser can be an interstate or intrastate pipeline, a local distribution company, or other entity. A first sale can also mean a sale by any of these entities if it is also the producer of the gas. The FERC has the right to define any sale as a first sale to prevent anyone from exceeding the maximum lawful price established under the NGPA. Sections 102 through 109 set forth the various categories of gas. These categories are now often identified by the NGPA section number (e.g., "What's the going price for 102 gas?"). Some sections set forth more than one category; for example, section 102 contains three categories of new gas: new Outer Continental Shelf (OCS) leases, new onshore wells, and new onshore reservoirs. Section 110 of the NGPA concerns the treatment of state severance taxes and other production-related costs.

Section 101 - Inflation Adjustment and Other General Price Ceiling Rules

Most natural gas prices are allowed to escalate with inflation and, in some cases, faster than inflation. Section 101 defines factors for this inflation adjustment. The adjustment consists of both an inflation factor and a consumer price index (CPI) correction factor. Together, these components make up the "annual inflation adjustment factor."

The inflation factor component is based upon the quarterly percent change in the gross national product (GNP) implicit price

deflator, which is expressed as an annual rate and published quarterly by the Department of Commerce. Added to this is a CPI correction factor of 0.2 percent so as to yield a better approximation of the CPI inflation factor in each month. The twelfth root of this sum (with some possible further adjustments) is the factor used to adjust prices on a monthly basis--it is called the monthly equivalent of the annual inflation adjustment factor.

The Federal Energy Regulatory Commission (FERC) is required by this section to publish the maximum lawful prices and the monthly equivalent of the annual inflation adjustment factor applicable to each category of natural gas no later than five days before the beginning of each month.

Other general rules under section 101 deal with ceiling prices. Ceiling prices for a month apply to the month of natural gas delivery rather than the date of sale or the contract date of sale. One key provision of this section is that if any natural gas qualifies for more than one ceiling price under the provisions of this Act, the provision resulting in the highest maximum lawful price is applicable. Also, the maximum lawful price for any category of gas does not override the price established under contract. This applies to a contract for first sale that does not exceed the maximum lawful price and a contract for first sale that is exempted from the maximum lawful price under subtitle B, which addresses the decontrol of wellhead prices.

Section 102 - Ceiling Price for New Natural Gas and Certain Natural Gas Produced from the Outer Continental Shelf

New natural gas can fall into three categories: gas from new outer continental shelf (OCS) leases, new onshore wells, and new onshore reservoirs. To qualify as a new OCS lease, it must be entered into on or after April 20, 1977; however, gas from an OCS reservoir discovered on or after July 27, 1976 on leases issued prior to April

20, 1977 also qualifies for the new natural gas ceiling price under a Congressional agreement, as stated in section 102(d) of the Act.

New onshore wells are of two kinds. First, any well for which drilling began after February 19, 1977 and which is 2.5 miles or more from the nearest marker well qualifies as a new onshore well. Second, any post-February 19, 1977 well that produced gas from a depth at least 1,000 feet below the deepest marker well within 2.5 miles also qualifies. A marker well is defined as a well from which natural gas was produced in commercial quantities anytime after January 1, 1970 and before April 20, 1977. Marker wells, however, do not include any wells for which the surface drilling began on or after February 19, 1977.¹

Natural gas from new onshore reservoirs that was not and could not have been produced through an old well before April 20, 1977 also qualifies as new natural gas under section 102. A reservoir, as defined by the NGPA, is any producible natural accumulation of natural gas, crude oil, or both confined by impermeable rock or water barriers and characterized by a single natural pressure system. However, none of the preceding provisions applies to natural gas produced in the Prudhoe Bay Area of Alaska and subject to the Alaska Natural Gas Transportation Act of 1976.

The maximum lawful price for any first sale of natural gas under section 102 is as follows:

¹The significance of the April 20, 1977 date is clear: President Carter, on that date, presented his energy program to a joint session of Congress. Less clear is the significance of the February 19, 1977 date, exactly sixty days prior to April 20. In most sections of the NGPA, the February date deals with the beginning of surface drilling of a well, while the April date deals with the production of gas in commercial quantities. Apparently, policymakers were allowing a minimum of two months for a well to be completed.

- (i) For April 1977: \$1.75 per million Btu
(ii) For the subsequent months: the price is calculated by the following formula:

$$P_n = P_{n-1} \left(\frac{\text{GNP}}{100} + 1.002 + \text{GF} \right)^{\frac{1}{12}} \quad (1)$$

where

P_n = the applicable price for such month;

P_{n-1} = the applicable price for the month immediately preceding such month;

GNP = the quarterly percent change in the GNP implicit price deflator expressed as an annual rate, for the appropriate quarter; and

GF = the growth factor, equal to 0.035 from April 20, 1977 through April 1981 and 0.04 thereafter.

As of July 1, 1983, the ceiling price for section 102 gas was \$3.448 per million Btu.²

Section 103 - Ceiling Price for New, Onshore Production Wells

To qualify as a new, onshore production well, the well must not be located on the outer-continental shelf; surface drilling must have begun on or after February 19, 1977; and state and federal well-spacing requirements must be satisfied. The well also cannot be located within a proration unit that was in existence at the time the drilling began, was applicable to the reservoir from which such natural gas is produced, or produced or was capable of producing natural gas in commercial quantities prior to February 19, 1977. A

²Federal Energy Regulatory Commission, Monitor, June 13, 1983, p. 8.

proration unit is any portion of a natural gas reservoir, drilling unit, or other similiar production unit that is effectively and efficiently drained by a single well. As in section 102, gas from the Prudhoe Bay of Alaska is excluded from these ceilings.

The initial ceiling price for section 103 gas produced in April 1977 was also \$1.75 per million Btu, and for subsequent months the price is given by the following formula:

$$P_n = P_{n-1} \left(\frac{\text{GNP}}{100} + 1.002 \right)^{\frac{1}{12}} \quad (2)$$

where the terms are as previously defined. However, effective January 1, 1985, all first sales of natural gas not committed to interstate commerce on April 20, 1977, produced from new, onshore production wells with depths less than 5,000 feet will be priced at the midpoint between the maximum lawful section 103 price and the maximum lawful section 102 price. As of July 1, 1983, the ceiling price for all gas covered by section 103 was \$2.792 per million Btu.³

Section 104 - Ceiling Price for Sales of Natural Gas Dedicated to Interstate Commerce

For natural gas that has been committed or dedicated to interstate commerce prior to April 20, 1977, the maximum lawful price for any first sale of gas is the higher of the following:

1. for April 1977, the "just and reasonable rate" that was established by the Commission for the first sale of natural gas on April 20, 1977 and, for any month thereafter, the maximum lawful price as calculated according to equation 2;
2. any just and reasonable rate established by the Commission after April 20, 1977 and before November 9, 1978, the date of enactment of this Act.

³Ibid.

As of July 1, 1983, the ceiling prices applicable to gas covered by section 104 ranged from \$2.311 per million Btu to \$0.286 per thousand cubic feet.⁴

Section 105 - Ceiling Price for Sales under Existing Intrastate Contracts

Section 105 applies to the first sale of natural gas delivered during any month, sold under any existing contract, which was not committed to interstate commerce before November 9, 1978.

Three distinct categories of natural gas are covered by this section. The first category is gas sold by a private party and subject to an intrastate contract on November 8, 1978 that specifies a delivery price of less than \$1.00 per million Btu for December 31, 1984. The maximum lawful price of this gas is the contract price while the contract is in effect. When the contract expires, the price is to equal \$1.00 per million Btu plus inflation adjustments beginning from April 20, 1977. Indefinite price escalator clauses are not permitted to operate for this category of gas.

The second category of "section 105" gas is that gas sold by a private party and subject to an intrastate contract on November 8, 1978 that specifies a delivery price that is greater than \$1.00 per million Btu for December 31, 1984, but where the contract price is higher than the applicable ceiling price for new (section 102) gas on November 8, 1978. While the contract is in effect, the maximum lawful price of this gas is the lesser of the contract price and the contract price on November 9, 1978 plus inflation adjustments according to equation 2, from April 20, 1977. These adjustments occur until the price equals the ceiling price for new gas under section 102, after

⁴Ibid.

which equation 1 applies with a growth factor (GF) equal to 0.03. Upon expiration of the contract, the contract price plus inflation adjustments from April 20, 1977 is the applicable ceiling price for this category of gas.

The third category of natural gas under section 105 is gas sold by a private party and subject to an intrastate contract on November 8, 1978 that specifies a delivery price of greater than \$1.00 per million Btu for December 31, 1984, but where the contract price is less than the applicable ceiling price for new (section 102) gas on November 8, 1978. While the contract is in effect, the maximum lawful price of this gas is the lesser of the contract price and the ceiling price applicable to new gas under section 102. Upon expiration of the contract, the contract price with inflation adjustments from April 20, 1977 makes up the maximum lawful price for gas in this category.⁵

Contracts pertaining to the latter two categories of "section 105" natural gas may contain indefinite price escalator clauses. These provisions allow for an adjustment or establishment of the price of gas by negotiation between parties or by reference to other prices for natural gas. However, they cannot operate to allow the price under the contract to exceed the ceiling price for new gas under section 102.

Section 106 - Ceiling Price for Sales under Rollover Contracts

This section covers interstate and intrastate rollover contracts. According to the NGPA, a rollover contract is a gas contract, signed after November 8, 1978, covering gas that was sold under a previous contract, which expired after November 8, 1978 at the end of a fixed term specified in the previous contract.

⁵Richard J. Pierce, Jr., Natural Gas Regulation Handbook (New York: Executive Enterprises Publications, 1980), pp. 46-47.

For interstate rollover contracts, section 106 applies to any first sale under any rollover contract of natural gas that was, or continued to be, committed to interstate commerce on November 8, 1978. The maximum lawful price of this natural gas is the higher of (1) the just and reasonable price the FERC sets in the month in which the effective date of the rollover contract occurs and (2) \$.54 per million Btu, for April 1977, adjusted for inflation according to equation 2 for months thereafter. As of July 1, 1983, the ceiling price for gas subject to an interstate rollover contract was \$.858 per million Btu.⁶

The intrastate rollover contract provisions apply to any first sale under any rollover contract of natural gas that was not committed to interstate commerce on November 8, 1978. The maximum lawful price of this gas is the higher of (1) the maximum price paid under the expired contract for the month in which the rollover contract occurs and (2) \$1.00 per million Btu. For subsequent months, the maximum lawful price will be adjusted for inflation according to equation 2. As of July 1, 1983, the ceiling price for gas subject to an intrastate rollover contract was \$1.595 per million Btu.⁷

Section 107 - Ceiling Price for High-Cost Natural Gas

High-cost natural gas includes gas from wells with a production depth of 15,000 feet or more, for which surface drilling began on or after February 19, 1977. It also includes natural gas from geopressurized brine, occluded natural gas produced from coal seams, Devonian shale, and other conditions that the FERC determines to present extraordinary risks or costs.

⁶FERC, Monitor, op. cit.

⁷Ibid.

Originally, the maximum lawful price for any first sale of high-cost natural gas was set according to the section 102 provisions; however, the Commission had the option to set higher maximum lawful prices to provide incentives for the production of high-cost gas. On November 1, 1979, all high-cost gas, excluding gas produced under "other conditions as the Commission determines to present extraordinary risks or costs," was deregulated. As of July 1, 1983, tight formation gas, a category of high-cost gas that is still regulated, had a ceiling price of \$5.584 per million Btu.⁸ In order to qualify for these provisions, a producer must file a statement with the FERC stating that he intends to drill for high-cost gas before surface drilling begins.

Section 108 - Ceiling Price for Stripper Well Natural Gas

To qualify as a stripper well under section 108, the natural gas cannot be produced in association with crude oil production, and, during the production period when the well is operating at its maximum flow rate, the maximum obtainable gas production cannot exceed 60 mcf/day unless the increase is a result of recognized enhanced recovery techniques. If a producer has a supply of low-cost old gas that can flow at a rate of, say, 80 mcf/day, he might try to receive stripper well prices by restricting flow to 60 mcf/day; however, this is illegal. The producer is not permitted to constrict the flow of a gas well in order to receive a higher ceiling price for stripper well production.

The maximum lawful price of any first sale of natural gas from a stripper well was \$2.09 per million Btu in May 1978. For months thereafter, the price increases according to equation 1 with the growth factor (GF) equal to 0.035 for any month beginning before April 20, 1981 and 0.04 for any month thereafter. As of July 1, 1983,

⁸Ibid.

the ceiling price applicable to stripper well gas was \$3.694 per million Btu.⁹

Section 109 - Ceiling Price for Other Categories of Natural Gas

This is the catch-all category for natural gas not covered in any other section. It includes gas from a new well not qualifying as new gas in section 102 or new onshore production well gas in section 103, gas committed or dedicated to interstate commerce on the date of the enactment of the NGPA (November 9, 1978) and for which a just and reasonable price under the NGA was not in effect, gas not committed or dedicated to interstate commerce on November 8 and which was not subject to an existing contract on that day, and Alaskan natural gas from Prudhoe Bay.

The ceiling price for any first sale of section 109 gas is the higher of \$1.45 million Btu for April 1977, increased for months thereafter according to equation 2, and the just and reasonable price prescribed by the Federal Energy Regulatory Commission. As of July 1, 1983, the ceiling price applicable to section 109 gas was \$2.311 per million Btu.¹⁰

Section 110 - Treatment of State Severance Taxes and Other Similar Production-Related Costs

The wellhead price of any gas is not considered to exceed the maximum lawful price under the NGPA if the first sale price of gas is greater than the maximum lawful price in order to recover state severance taxes or certain production-related costs borne by the producer and permitted by the FERC. These include the costs of compressing, gathering, processing, treating, or liquifying the gas.

⁹Ibid.

¹⁰Ibid.

Under the Carter administration, the FERC tended to allow recovery of few of these miscellaneous costs as an add-on to the price ceilings established in this Act. However, under the present administration, this policy appears to be changing.¹¹

Subtitle B - Decontrol of Certain Natural Gas Prices

Subtitle B (sections 121, 122, and 123) concerns the decontrol of certain natural gas prices. Section 121 deals with the elimination of price controls for certain natural gas sales. Section 122 deals with standby authority for the reimposition of price controls. Section 123 requires two reports to the President and the Congress by the Department of Energy one due by July 1, 1984 and another by January 1, 1985. These reports must address natural gas prices, supplies, demand, competitive conditions, and market forces. Each report must also include an evaluation of whether equilibrium exists between supply and demand in the natural gas market.

Sections 121 and 122 only are discussed below.

Section 121 - Elimination of Price Controls for Certain Natural Gas Sales

For the purposes of wellhead price decontrol, natural gas under the NGPA comes from wells that fall into three groups. The first is natural gas from wells that are presently deregulated. High-cost

¹¹Effective March 7, 1983, the FERC is amending 18 CFR Parts 2, 154, 270, and 271, regulations implementing section 110 of the NGPA. The FERC is eliminating the application procedures that were previously necessary to recover production-related costs, eliminating minimum quality standards that set maximum allowable levels of natural gas impurities, and eliminating rules that minimized production cost increases for gas sold in the intrastate market. The FERC has also proposed setting generic allowances for the cost to producers of transporting gas from the wellhead to any pipeline or local distribution company and for the production costs of compressing this gas for delivery. See 48 Fed. Reg. 5152-97 (1983).

natural gas that qualifies under section 107(c)(1-4) of the NGPA is presently the only category of gas that is totally decontrolled. Natural gas, such as "tight sands" or "tight formation" gas, that qualifies under section 107(c)(5) by being "produced under such conditions as the Commission determines to present extraordinary risks or costs" continues to be regulated unless deregulated under some other provision of the NGPA.

The second group of wells subject to decontrol is those which are to be deregulated in 1985 and 1987. New natural gas ("section 102" gas excluding section 102(d), OCS reservoirs discovered on or after July 27, 1976), new onshore production well gas ("section 103" gas) not dedicated to interstate commerce on April 20, 1977 from wells deeper than 5,000 feet are to be deregulated effective January 1, 1985. Also gas sold that is subject to the provisions of either an intrastate contract without indefinite price escalator clauses or an intrastate rollover contract on November 8, 1978 that specifies a price greater than \$1.00 per million Btu on December 31, 1984 will be deregulated on January 1, 1985. Natural gas from new onshore production wells not dedicated to interstate commerce on April 20, 1977 with a production depth less than or equal to 5,000 feet will be deregulated on July 1, 1987.

The third group contains all the wells producing natural gas subject to continued regulation. This includes the following:

1. Natural gas from OCS reservoirs discovered on or after July 27, 1976 ("Section 102(d)" gas).
2. Any natural gas dedicated to interstate commerce including some gas under section 103 and all gas under section 104.
3. Natural gas under the provisions of an intrastate contract or an intrastate rollover contract on November 8, 1978 that specifies a price of December 31, 1984 that is less than or equal to \$1.00 per million Btu.

4. Natural gas under the provisions of an intrastate contract in which the price is established under an indefinite price escalator clause and is greater than \$1.00 per million Btu.
5. Natural gas under the provisions of an interstate rollover contract ("section 106" gas).
6. Natural gas produced under extraordinary risks or costs ("section 107(c)(5)" gas).
7. Stripper well natural gas ("section 108" gas) not qualifying under any other provision of the NGPA.
8. Other categories of natural gas as specified in section 109 of the NGPA.

Section 122 - Standby Price Control Authority

Under section 122 of the NGPA, the President (by written order) or Congress (by concurrent resolution) may reimpose maximum lawful prices for natural gas that is to be deregulated on January 1, 1985. The reimposition of price controls may not take effect earlier than July 1, 1985 nor later than June 30, 1987 and may remain in effect only for a period of 18 months.

The maximum lawful price that may be reimposed for gas at this time is the maximum lawful price computed under section 102, except for the deregulated section 103 gas. The maximum price for the section 103 gas deregulated on January 1, 1985 is the price for section 103 new onshore production gas from wells 5,000 feet or less in depth as computed for that month. Maximum lawful prices may be reimposed only once under this section.

Title II - Incremental Pricing

Title II contains the incremental pricing provisions of the NGPA--provisions intended to shift the burden of rising gas costs to industrial customers using gas for boiler heating and other large scale uses. Title II contains eight sections. Section 201 of the NGPA provides for the implementation of Phase I of incremental pricing; section 202 provides for the possible expanded application of incremental pricing, known as Phase II. Section 203 specifies the costs subject to being shifted onto these industrial customers. Section 204 sets out the method to be used by interstate pipelines for passing costs through to incrementally priced industrial customers. Section 205 requires local distribution companies to pass costs through incrementally priced industrial customers. Section 206 allows exemptions to the pass-through requirements for certain customers, and section 207 makes special provisions for the treatment of certain gas imports. Each of these sections is discussed in further detail below.

Section 208 of the NGPA concerns gas produced from Prudhoe Bay in Alaska and transported through a gas transmission system approved under the Alaska Natural Gas Transportation Act of 1976. Section 208 provides that any portion of the first sale cost of this Alaskan gas that is not subject to incremental pricing and any transportation charge incurred by an interstate pipeline must be "rolled-in" to end user prices.

Sections 201 and 202 - Industrial Boiler Fuel Use and Other Industrial Uses

Prior to the NGPA, the FERC made several unsuccessful attempts to institute what is known as "incremental pricing" into natural gas rate design procedures. Incremental pricing would allocate the low

unit costs of "old natural gas" to high priority (mainly residential) consumers, while the higher costs associated with "new gas" would be allocated to low priority users (mainly, industrial customers with large boilers). This would essentially move the price of natural gas paid by certain industries nearer to the price of alternate fuels.

However, passage of the NGPA in 1978 instituted a modified version of incremental pricing. The Act represents a compromise between advocates of rolled-in pricing and those of incremental pricing. It requires the FERC to separate consumers into two groups: (1) large industrial boiler fuel facilities and certain other industrial gas users, and (2) the remaining industrial, commercial, and residential gas users. As described in sections 201 and 202, industrial boiler fuel facilities and other large industrial users are required to pay a disproportionate amount of the higher costs associated with new gas. Section 201 provides that the FERC promulgate a rule requiring incremental pricing of gas to existing large and future industrial boiler facilities no later than 12 months after the enactment of the NGPA. Section 202 provides that the FERC promulgate a rule expanding the application of incremental pricing to other industrial users not later than 18 months after the enactment of the NGPA. Section 202 also has a provision allowing either House of Congress to disapprove the section 202 rule promulgated by the FERC.

Section 203 - Acquisition Costs Subject to Pass-through

The costs that a pipeline may pass-through to its incrementally priced customers are as follows:

1. That portion of the first sale acquisition cost of new natural gas, natural gas under intrastate rollover contracts, new onshore production well gas, and liquified natural gas (LNG) imports, which exceeds the incremental pricing thres-

hold of \$1.48 per million Btu for March 1978. In subsequent months the incremental pricing threshold is adjusted for inflation by equation 2;

2. That portion of the first sale acquisition cost of stripper well natural gas, and imported natural gas, other than LNG, which exceeds the maximum lawful price computed under section 102 for the month in which delivery or importation of the gas occurs;
3. That portion of the first sale acquisition cost of high-cost (section 107) natural gas which exceeds 130 percent of the Btu-equivalent of the landed cost of number 2 fuel oil in New York harbor during an appropriate period preceding the month in which delivery of the gas occurs;
4. That portion of the first sale acquisition cost of Alaskan natural gas from Prudhoe Bay that exceeds the cost computed in section 109 and any amount paid to any person other than the producer for costs of gathering, processing, treating or other similiar processes completed before the delivery of such gas to the pipeline system;
5. That portion of the cost of natural gas attributable to an increase in state severance taxes which results from a state law enacted after December 1, 1977;
6. The amount of any surcharge paid by any interstate pipeline for natural gas acquired from another interstate pipeline.

Section 204 - Method of Pass-through

Section 204 requires interstate pipelines subject to incremental pricing to establish an incremental pricing account. Costs subject to pass-through, as described in section 203, must be credited to the pipeline's account and may not be allocated to the rates and charges of the pipeline except as a surcharge on the rates and charges for

natural gas delivered to an incrementally priced industrial facility. This facility must either be served directly by the interstate pipeline or served indirectly by another interstate pipeline or local distribution company.

Once the costs are passed through, their amounts are to be deducted from the pipeline's incremental pricing account. If the rates and charges for natural gas delivered to an incrementally priced industrial facility by an interstate pipeline are not less than the appropriate alternative fuel cost, then the excess amount may also be deducted from the pipeline's account and allocated by the pipeline in any manner that would be permitted in the absence of the NGPA.

According to the NGPA, the appropriate alternate fuel cost for any region is the price per million Btu of number 2 fuel oil paid by industrial users for such fuel within the region. However, the NGPA also provides that the FERC may reduce the appropriate alternate fuel cost to the price of number 6 fuel oil within a region if it determines that the reduction is necessary to prevent widespread fuel switching within that region. The FERC has done so for all regions of the country, and the alternate fuel cost is now the price of number 6 high sulphur fuel oil, also known as residual fuel oil, or "resid".

Section 205 - Local Distribution Company Pass-through Requirements

Section 205 requires that any surcharge paid by any local distribution company be passed directly through to the incrementally priced industrial facilities it serves. It also prohibits state commissions from reallocating these costs in the retail rates of local distribution companies so as to offset the required surcharges. This does not, of course, preclude state commissions from exercising their authority under state law to regulate local distribution companies.

Sections 206 and 207 - Exemptions and Treatment of Certain Imports

Exemptions to these pass-through requirements include existing small industrial boiler fuel facilities (those not exceeding an average of 300 mcf per day during any month of a base period) and agricultural uses of natural gas for which an alternate fuel is not economically practicable or reasonably available. Schools, hospitals and other similiar facilities, electric utilities, and qualifying cogenerators are also exempt. The provisions also do not apply to certain LNG and other gas imports entering the country on or before May 1, 1978.

The Remainder of the NGPA

The NGPA contains four additional titles. Title III of the NGPA grants additional authorities and sets forth additional requirements. Title IV details natural gas curtailment policies. Title V contains provisions concerning the administration, enforcement, and review of the NGPA. Title VI concerns coordination with the Natural Gas Act and also contains other miscellaneous provisions. Each of these titles is discussed in further detail below.

Title III - Additional Authorities and Requirements

Title III is divided into two subtitles. Subtitle A addresses emergency authority under the Act and under the Emergency Natural Gas Act of 1977 (ENGA). It gives the President authority similar to that contained in ENGA to declare a natural gas supply emergency.

Subtitle B addresses other authorities and requirements such as authorization of certain specific sales and transportation of natural gas, especially the sale and transport of natural gas from intrastate pipelines to interstate pipelines. It also gives the FERC the authority to intercede in certain contractual arrangements.

Title IV - Natural Gas Curtailment Policies

Title IV details the curtailment policies for natural gas. It establishes the first three priorities that must be contained in any interstate pipeline curtailment plan to be as follows:

1. Residential and small commercial requirements, the requirements of schools, hospitals, and similiar institutions and requirements necessary to protect health, safety, and property.
2. Essential agricultural uses in which alternate fuels are not reasonably available or economically practical.
3. Essential industrial processes and feed stock uses.

Title V - Administration, Enforcement, and Review

Except where it is expressly provided otherwise, the FERC is the administrator of the NGPA. However, the Act specifically states that the state or federal agency having regulatory jurisdiction over the production of natural gas will determine the price categories for gas as described in Title I of the Act. The FERC can only categorize gas when the state or federal agency explicitly waives its authority.

The FERC may bring an action in any appropriate District Court of the United States to enforce compliance upon any person engaging in a practice that constitutes a violation of the NGPA. The Secretary of Energy and the President also have limited and emergency powers of enforcement.

Judicial review is provided in the United States Court of Appeals in the District of Columbia or in the circuit where the person aggrieved is located or has his principal place of business.

Title VI - Coordination with Natural Gas Act; Miscellaneous Provisions

Title VI coordinates the NGPA with the Natural Gas Act and discusses its effect on state laws. It is important to notice that any state may establish maximum lawful prices for natural gas produced in such state as long as the prices do not exceed the maximum lawful prices established in Title I.

Title VI also authorizes the FERC to oversee the purchase price of gas for evidence of fraud or abuse, as discussed in the subsection "Guaranteed Pass-through" in the following section.

FERC Actions under the NGPA

Since the enactment of the NGPA, the FERC has undertaken several actions that affect the implementation of the NGPA. Some of these actions concern the implementation of incremental pricing; others concern pass-through of additional purchase gas cost under purchase gas adjustment filings. The FERC has also issued a notice of inquiry concerning the elimination of price vintaging and establishes new maximum lawful prices for section 104, 106, and 109 gas. It has approved and held conferences on off-system sales; and, recently, it has issued policy statements concerning the effect of take-or-pay contracts. Each of these sets of actions is dealt with in further detail below.

Implementing Incremental Pricing

The Federal Energy Regulatory Commission is charged with the responsibility of implementing the incremental pricing provisions of the NGPA through rulemaking. The FERC issued final rules on October 5, 1979 requiring that incremental costs exceeding the applicable incremental pricing threshold must be passed through to non-exempt industrial boiler fuel facilities as provided by section 201 of the NGPA. These rules became known as Phase I incremental pricing

regulations. The rules provide that gas used in industrial boiler fuel facilities that were in existence on November 9, 1978 and did not consume more than an average of 300 mcf per day for boiler fuel during any calendar month of calendar year 1977 are exempt from incremental pricing. Gas for agricultural uses certified as essential by the Secretary of Agriculture as well as schools, hospitals, and similar institutions are also exempt from incremental pricing. In addition, gas used in qualifying cogeneration facilities and by electric utilities to generate electricity is exempt.

The FERC determined that non-exempt industrial boiler fuel facilities under the Phase I incremental pricing program ought to pay no more than the price that they would pay for oil that they could burn as an alternative fuel. The Phase I incremental pricing regulations provide a regulatory framework for the calculation and billing of incremental pricing surcharges. The regulations provide that a "reduced PGA" method of calculating and billing incremental pricing surcharges is to be used. The object of the "reduced PGA" method is to estimate in advance the total gas acquisition costs and the portion of those costs that would ultimately be recovered by the incremental pricing surcharge. The estimated incremental pricing surcharge is to be subtracted from the estimated total gas acquisition costs. The remainder is to be collected through the "reduced PGA." In addition, non-exempt industrial facilities are charged an incremental pricing surcharge.

Here is how the reduced PGA method works. Each interstate pipeline, prior to filing a purchased gas adjustment request, estimates the total gas acquisition costs it will incur during the upcoming PGA period and the portion of this total that will be "incremental costs" subject to being passed through as an incremental pricing surcharge. The interstate pipeline then projects the total maximum surcharge absorption capacity (MSAC) of the non-exempt

industrial boiler fuel facilities that it serves. A facility's MSAC is the total amount of incremental cost that the facility can absorb before its gas price rises above the price of the alternative fuel. The interstate pipeline's projected MSAC is to be based upon the MSAC estimates of the local distribution companies it serves. Likewise, an interstate pipeline reports its own MSAC projections to any "upstream" pipelines. The interstate pipeline that is most upstream compares its total projected MSAC with its total projected gas costs subject to the surcharge for the upcoming PGA period. The upstream interstate pipeline then uses the lesser of these two amounts (often the projected MSAC) to reduce its original PGA rate to the "reduced PGA" rate. All customers are billed this "reduced PGA" rate. The non-exempt industrial facilities also pay an additional incremental pricing surcharge based on actual usage and actual alternative fuel price ceilings established for the month in which the usage occurs. This incremental pricing surcharge is the lesser of the total actual MSAC of the past month and the total incremental gas costs; each non-exempt industrial facility is billed based on the lesser of these. Any incremental gas acquisition cost that the "upstream" pipeline does not recover may be recovered in a later PGA period. Unrecovered incremental gas acquisition cost incurred directly by local distribution companies may be recovered by any manner permitted by state regulation.¹²

On June 13, 1980, the FERC exempted all non-exempt industrial boiler fuel facilities from paying more than the price of number 6 fuel oil, the fuel thereafter designated by the FERC as the relevant alternate fuel. The FERC made this rule permanent on July 24, 1981.¹³ When the rates for all non-exempt industrial boiler fuel customers of an interstate pipeline or distributor reach the level

¹²44 Fed. Reg. 57726-54 (1979); FERC Order No. 49.

¹³FERC Order No. 167 (July 24, 1981).

of number 6 fuel oil, its other customers, including residential and small commercial users, have to bear a portion of the higher gas costs.

The FERC was required under the NGPA to develop a second incremental pricing rule that would broaden the application of incremental pricing to small industrial boiler facilities. According to the NGPA, this Phase II incremental pricing rule was subject to a single house veto of the Congress. When the FERC promulgated its final rules to implement Phase II incremental pricing,¹⁴ the House of Representatives vetoed it. The FERC thereafter discontinued its rulemaking concerning implementation of Phase II incremental pricing, citing the intent of Congress as a reason to dismiss the docket.¹⁵ Since then, however, the D.C. Court of Appeals struck down the legislative veto of the Phase II Incremental Pricing rules as a violation of the "separation of powers" doctrine. The U.S. Supreme Court accepted an appeal of the case and recently affirmed the decision of the Court of Appeals.

Guaranteed Pass-through

Section 601(c)(2) of the NGPA provides that interstate pipelines are allowed to pass through the price paid to purchase natural gas upon two conditions. The first condition is that the price cannot exceed the maximum lawful price under the NGPA, the price is decontrolled pursuant to the NGPA, or the price is otherwise deemed reasonable according to section 601(b) of the NGPA.¹⁶ The second condition is that purchase is not held by the FERC to be excessive due to fraud, abuse, or similar grounds.¹⁷

¹⁴45 Fed. Reg. 31622-80 (1980).

¹⁵45 Fed. Reg. 52359-65 (1980).

¹⁶Natural Gas Policy Act, sections 601(c)(2), 601(b).

¹⁷Ibid., section 601(c)(2).

The FERC announced a general policy statement on February 4, 1982 in order to provide guidance for the efficient disposition of cases in which the fraud standard is an issue. In its statement of policy, the FERC limited the consideration of the "fraud, abuse, and similar grounds" standard to a consideration of whether the amounts paid for purchased gas were excessive due to a misrepresentation of any kind.¹⁸

The FERC based its reasoning upon the definitions of fraud found in existing legal authorities.¹⁹ The FERC stated that to raise the issue of fraud, an intervenor must file a complaint alleging that the interstate pipeline, the first seller, or both made a fraudulent misrepresentation or concealment, and that because of the fraudulent misrepresentation or concealment, the amount paid by the interstate pipeline to the first seller was higher than it would have been otherwise.²⁰ A misrepresentation is considered fraudulent if the maker "knows or believes that the matter is not as he represents it to be, does not have the confidence in the accuracy of his representations that he states or implies, or knows that he does not have the basis for his representation that he states or implies."²¹ In other words, a fraudulent misrepresentation requires intent or scienter (prior knowledge).

¹⁸47 Fed. Reg. 6253-63 (1982).

¹⁹The Statement of Policy cited legal authorities that included: 37 Am. Jur. 2d, Fraud and Deceit; W. Prosser, Handbook of the Law of Torts (4th ed. 1971), 2nd Restatement of Torts.

²⁰18 CFR Part 2, §2.300(a).

²¹Restatement of Torts 2nd, Section 536.

The FERC applied the "ejusdem generis rule" of statutory construction in defining the terms "abuse" and "similar grounds." The ejusdem generis rule of statutory construction limits the meaning of general words following words of a particular and specific meaning; the meaning of the general words is not to be construed in their widest extent, but is only to be interpreted in terms of the words with particular and specific meaning.²² Thus, FERC stated that in order to raise the issue of abuse, an intervenor must file a complaint alleging that the interstate pipeline, the first seller, or both made (1) a negligent misrepresentation or concealment, or a misrepresentation or concealment in disregard of duty, and (2) that because of that misrepresentation or concealment, the amount paid by the interstate pipeline to the first seller was higher than it would have been otherwise.²³ In order to raise the issue of similar grounds, an intervenor must allege that the interstate pipeline, the first seller, or both made (1) an innocent misrepresentation of facts, and (2) that because of the innocent misrepresentation the amount paid to the first seller was higher than it would have been otherwise.²⁴

The FERC statement of policy limited the "fraud, abuse, or similar grounds" standard to a consideration of whether amounts paid to first sellers were excessive as a result of a misrepresentation or concealment. It does not encompass imprudent business judgments. The Commission made it clear that the "fraud, abuse, or similar grounds" standard would neither be used as a market ordering device nor as a backdoor mechanism for the Commission to regulate prices otherwise set or deregulated by the NGPA.

²²See, for example, *Goldsmith v. U.S.* 42 F.2d 133,137 (1930).

²³18 CFR Part 2, §2.300(b).

²⁴18 CFR Part 2, §2.300(c).

It is important to note that a FERC policy statement does not have the force and effect of law. It is instead an articulation of FERC policy disposition, which it intends to apply unless circumstances demonstrate that the application of the statement is inappropriate.

The FERC statement of policy as issued in the Federal Register also contained the concurring opinion of Commissioner J. David Hughes²⁵ in which he agreed with the conclusion in the statement of policy that fraud, abuse, or similar grounds includes all the forms of misrepresentation or concealment that lead to excessive amounts paid for gas. He stated, however, that if the statement of policy were interpreted to limit the fraud, abuse, or similar grounds standard to misrepresentations concerning the amounts paid for gas, he would find the statement of policy to be too restrictive. There might be misrepresentation or concealments that did not directly concern price that would be prohibited under the standard. Also, he stated that he was concerned that abuses (or other similar grounds) could take a form other than misrepresentations or concealments. For instance, concerted or repetitive behavior by a pipeline or first seller could show a disregard for the pipeline's duties and be abusive without ever involving misrepresentation or concealment. He reserved his opinion about whether these other actions would constitute fraud, abuse, or similar grounds.

In a recent FERC case, an administrative law judge held that the Columbia Gas Transmission Corporation's practice of cutting back quantities of low-cost gas supplies before cutting back all higher cost gas supplies to at least take-or-pay level was an "abuse" under

²⁵47 Fed. Reg. 6263 (1982).

section 601(c)(2) of the NGPA. Pass-through of a portion of its PGA increase was denied.²⁶ No misrepresentation and concealment was involved. Judge Levant also found that contractual provisions inhibiting Columbia's ability to adjust to changing supply requirements and market prices were unjust and unreasonable under section 5 of the Natural Gas Act of 1938. He ordered Columbia to desist from engaging in gas acquisition practices that fail to take into consideration the marketability of gas for all its customers, and to conduct a systemwide marketability study.²⁷ As of this writing, this decision was being reviewed by the Commission.

Administrative Decontrol

The FERC undertook another action in implementing the NGPA when, on April 28, 1982, it issued a notice of inquiry concerning the impact of the NGPA on current and projected natural gas markets.²⁸ The notice of inquiry was to investigate the existence of serious economic distortions in natural gas markets and to examine FERC administrative authority to reduce those distortions. The notice of inquiry included a description of an administrative option open to the FERC, involving the elimination of vintaging of gas prices for section 104, 106, and 109 gas. The FERC staff stated that the Commission could, by using its authority pursuant to sections 104(b)(2), 106(c), and 109(b)(2) of the NGPA, establish just and reasonable rates for section 104, 106, and 109 gas, and thus eliminate vintage pricing of that gas. By

²⁶Initial Decision on Purchased Gas Adjustment Filings, Dockets No. TA81-1-21-001, TA81-2-21-001 (December 30, 1982), p. 75.

²⁷Initial Decision, op. cit., p. 77.

²⁸47 Fed. Reg. 19157-71 (1982).

eliminating vintage pricing, it might be possible to reduce the size of any gas cushion causing a bidding disparity among interstate pipelines or between interstate and intrastate pipelines.

The FERC also sought comments on its authority for this action as well as the advantages and disadvantages of this and other possible administrative actions. These include developing incentive rates of return to assure that pipelines attempt to minimize gas purchase costs, limiting indefinite price escalators and take-or-pay contract provisions, requiring the filing of all gas purchase contracts, and revising FERC ratemaking authority under sections 4 and 5 of the NGA so that decontrolled gas is subject to market forces.

Off-System Sales

Many pipelines have been authorized to make off-system sales in order to sell greater quantities of gas in the face of falling sales to their on-system customers.²⁹ Off-system sales were thought to be a way of lessening or eliminating a pipeline's potential take-or-pay liability, while at the same time giving the buyer access to less expensive gas. During the last two years, the FERC authorized off-system sales of approximately 1 tcf of gas. However, only 240 bcf has actually been sold. In order to discuss the advantages and disadvantages of off-system gas sales with the interested parties, the FERC held a two-day public conference on November 4 and 5, 1982.

²⁹Many pipelines are authorized by the FERC to make off-system sales. For instance, see FERC Docket Nos. CP81-236-002, CP810-001/002, CP81-303-004, CP81-322-002, and CP82-356/ST82-322.

On April 25, 1983, the FERC announced a general statement of policy regarding off-system sales by interstate pipelines.³⁰ The policy statement was issued at least partially in response to concerns voiced at the November 1982 conference. One set of concerns was voiced by some of the traditional customers of pipelines that make off-system sales. They objected that the prices of off-system sales might be lower than that available to on-system customers. They also expressed concern that the pipelines are buying gas at a high cost to replace the gas that is being sold off-system at a lower cost.

Certain intrastate pipelines have also objected to off-system sales. Their objection is based on a claim that interstate pipelines with gas cushions are using their off-system sales to undercut the prices in the intrastate pipelines' markets; thus, the interstate pipeline is simply transferring the problems of softening demand, excess deliverability, take-or-pay exposure, shut-in wells, and competition from oil from the interstate market to the intrastate market.

In order to address these concerns, the FERC announced that an appropriate off-system sales policy would serve the following objectives:

- (1) Permit interstate pipelines with excess gas supplies to sell to pipelines and local distribution companies experiencing a physical gas shortage.
- (2) Permit pipelines with excess gas to sell to pipelines, local distribution companies, and end-users who would otherwise purchase more expensive gas.

³⁰See 48 Fed. Reg. 20124-20131 (1983).

- (3) Lessen take-or-pay problems.
- (4) Accomplish the first three objectives without unduly burdening the selling pipeline's traditional customers and without simply transferring problems of the interstate pipelines to the intrastate market.³¹

The FERC then announced several criteria that should be met in order to meet the above objectives. One criterion is that where the proposed off-system sale is between two interstate pipelines, the sale should be priced at the higher of the selling pipeline's system average load factor rate or its average section 102 gas acquisition cost. This criterion is meant to ensure that off-system sales would not be made available at a price lower than that available to on-system customers and also that on-system customers are left no worse off than if the off-system sale had not occurred. The criterion also would allow the selling pipeline to negotiate a higher price if the purchaser were not an interstate pipeline.

The second criterion states that when there are allegations of a market loss by an established intrastate supplier of a buyer identified in a specific off-system sales transaction, there would be a case-specific analysis of the competitive positions of the suppliers. An inquiry would be made regarding whether the interstate pipeline may be able to undercut the intrastate pipeline by charging only commodity costs off the usual system and recovering its fixed costs on the system. If so, the price of the off-system sale may be increased by an amount reflecting some portion of the interstate pipeline's fixed rate.

³¹Ibid.

An interstate pipeline must also meet two other criteria to be eligible to make off-system sales. The pipeline must demonstrate that it has a sufficient surplus so that sales to existing customers will not be impaired, and it must demonstrate at least the potential to incur liabilities under its take-or-pay provisions.

Any off-system sales allowed by the FERC under its statement of policy will be allowed for a one-year period. Off-system sales will continue to be authorized on a "best efforts" basis, with a requirement that an off-system sale be interrupted prior to the interruption of any on-system customer.

Take-or-Pay Contracts

On December 16, 1982, as part of its implementation of the NGPA, the FERC issued a statement of policy concerning take-or-pay provisions in gas purchase contracts.³² It says that the FERC intends to apply a rebuttable presumption in general rate cases (under sections 4 and 5 of the NGA) that prepayments to producers, which are pursuant to gas purchase contracts entered into on or after December 23, 1982, will not be given rate base treatment if the prepayments are made due to take-or-pay provisions exceeding 75 percent of annual deliverability.³³

³²47 Fed. Reg. 57268-70 (1982).

³³18 CFR Part 2, §2.103.

APPENDIX D

CONTRACT PROVISIONS UNDER THE NGPA

Since the passage of the NGPA, the wellhead prices of gas have been allowed to differ greatly for the various NGPA categories of gas. The pricing provisions of the NGPA address only the ceiling prices for wellhead gas. The NGPA does not require that the first sale of gas in any category be at the ceiling price. Prices are rising not only because of rising ceilings but also because of contract clauses that permit the gas price to follow the ceiling increases and because of clauses that affect the mix of gas from various producers. Also, fears of future price increases in 1985 are tied to contract provisions that take effect upon deregulation. In this appendix, we present information about the types and frequency of occurrence of such clauses in contracts entered into by pipelines and producers. This information is selected from data concerning contract clauses in 1980 gathered by Decision Analysis Corporation for a 1982 report of the Energy Information Administration.¹ The information selected covers contract deregulation provisions, buyer protection clauses, take-or-pay provisions, and the duration of contracts that can be found under producer/pipeline contracts under the NGPA.

Deregulation Clauses

According to the study conducted for the Energy Information Administration, a significant fraction of gas in every NGPA category is being sold under contracts with some type of deregulation

¹Energy Information Administration, U.S. Department of Energy, Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market, An Analysis of the Natural Gas Policy Act and Several Alternatives, Part II, DOE/EIA-0330, prepared by Decision Analysis Corporation (Washington, D.C.: 1982).

provision. A deregulation provision is a contract clause that states how the price of gas will be determined if price controls imposed by regulatory authorities end or do not apply. These deregulation provisions include two-party and three-party favored nation clauses, redetermination clauses with an oil parity provision, and minimum price specified clauses.

The results of the study shown in table D-1 contain information on the quantity of gas sold under contract in 1980 by NGPA category. The first column of table D-1 indicates NGPA categories. The second column contains the quantity of gas sold under contract in 1980 for each of these NGPA categories. The third, fourth, and fifth columns of table D-1 contain the percentages of gas sold with three types of price escalation provisions. The third, fourth, and fifth columns add up to 100 percent for each category of gas. The third column contains the percentage of gas sold with definite price escalator clauses and no deregulation provisions. The fourth column contains the percentage of gas sold with highest allowed regulated rate provisions, which permit the producer to receive the highest rate allowed by regulators, and no deregulation provisions. The fifth column contains the percentage of gas sold with a deregulation provision.

As shown in table D-1, 66 percent of old interstate gas and interstate rollover contract gas sold under contract in 1980 was covered by some type of deregulation provision. However, this gas will remain regulated after 1985. A large volume of old intrastate gas and intrastate rollover gas is expected to be deregulated in 1985, and in 1980 54 percent of this gas was sold under contracts with deregulation provisions.

Similarly for new gas, a high proportion of the contract volume was sold under contracts with deregulation provisions. This is true for 63 percent of the contracted volume of section 102 new gas, and 53 percent of the contracted volume of section 103 new gas.

TABLE D-1

QUANTITY AND
PRICE ESCALATION PROVISIONS OF GAS UNDER CONTRACT IN 1980,
BY NGPA CATEGORY

Gas Designation under NGPA	Quantity of Gas Sold under Contract in 1980 (Quadrillion Btu) [†]	Percentage of Gas Sold under a Definite Price Escalator and No Deregulation Provision	Percentage of Gas Sold under a Highest Allowed Regulated Rate Clause and No Deregulation Provision	Percentage of Gas Sold under a Deregulation Provision
Section 104/106(a)	6.31	8	26	66
Section 105/106(b)	6.23	40	6	54
Section 102	2.67	6	31	63
Section 103	2.76	32	15	53
Section 107	0.44	2 ^a	a,*	98 ^b
Section 108	0.35	44	23	33

Source: Energy Information Administration, op. cit., tables 1 and 10

* Less than .5 percent

^a Results are based on five or less sampling units.

^b For the section 107 gas that is already deregulated, the entry refers to any redetermination or renegotiation price clause currently being used.

[†] A quadrillion Btu is a billion million Btu, or in scientific notation 10^{15} Btu.

Nearly all (98 percent) of the contracted volume of high-cost gas is deregulated and has its price determined by redetermination or renegotiation clauses. Only 33 percent of the contracted volume of stripper well gas was sold under contracts with deregulation provisions.

The most common deregulation clause is some type of most favored nation clause. That is, the contract specifies that when price regulation ends, the contract price is to be determined on a most favored nation basis. As shown in table D-2, in 1980 92 percent of the gas sold under the old interstate and interstate gas rollover contracts was subject to some type of most favored nation clause, while only 66 percent of the gas sold under the old intrastate gas and intrastate gas rollover contracts was subject to contracts containing a most favored nation clause.

Of the new gas sold under contracts containing some type of deregulation clause, 85 percent of the volume of section 102 new gas and 65 percent of the volume of section 103 new gas sold were subject to contracts containing a most favored nation clause. Thus, much of the new gas, which will be deregulated in 1985 and 1987, will be subject to most favored nation clauses upon deregulation.

Most of the high-cost gas sold is sold under contracts containing most favored nation clauses. As most of the high-cost, section 107 gas is currently deregulated, many of the contracts with most favored nation clauses are currently in operation.

As shown in the last column of table D-2, a majority of the most favored nation clauses in 1980 gas contracts containing deregulation provisions were three-party most favored nation clauses. Three-party

TABLE D-2

FREQUENCY OF MOST FAVORED NATION CLAUSES
 IN GAS CONTRACTS CONTAINING DEREGULATION PROVISIONS IN 1980, BY NGPA CATEGORY

	(1)	(2)	(3)	(4)
Gas Designation under NGPA	Quantity of Gas Sold under a Deregulation Provision in 1980 (Quadrillion Btu)	Gas Sold under a Most Favored Nation Clause as a Percentage of Gas Sold under a Deregulation Provision	Gas Sold under a Two-Party Most Favored Nation Clause as a Percentage of Gas Sold under a Deregulation Provision	Gas Sold under a Three-Party Most Favored Nation Clause as a Percentage of Gas Sold under a Deregulation Provision
Section 104/106(a)	4.13	92	4	89
Section 105/106(b)	3.37	66	N/A	N/A
Section 102	1.67	85	12	79
Section 103	1.45	65	10	61
Section 107	0.44	88	0	88
Section 108	0.12	56	7 ^a	53

Source: Energy Information Administration, op. cit., tables ES2, 2, and 11

^aResults are based on five or less sampling units.

N/A means "not available."

most favored nation clauses can be particularly harmful because they tie the price of gas to the highest price paid by any pipeline to any producer in the defined area. A two-party most favored nation clause merely ties the price to the highest price that the pipeline itself has paid to any producer in the area. Thus, three-party most favored nation clauses are more easily triggered by high price gas contracts than are two-party clauses.

Some of the gas contracts contain deregulation clauses that are redetermination clauses, that is, provisions specifying that upon deregulation the price of gas will be set according to the value of certain preselected factors. These redetermination clauses are sometimes tied to the price of crude oil, sometimes to the price of number 6 fuel oil, and sometimes to the price of number 2 fuel oil. Because some portion of these contract provisions are tied to number 2 fuel oil, they could, when coupled with three-party most favored nation clauses, result in gas prices above the cost of the alternative fuel for some industrial customers. As shown in table D-3, some of the 1980 gas contracts containing deregulation clauses also contained redetermination clauses that were tied to some form of oil parity. Redetermination clauses tied to an oil parity were found in gas contracts covering 12 percent of the sales of old interstate and interstate rollover gas, 28 percent of the sales of section 102 new gas, 14 percent of the sales of section 103 new gas, and 24 percent of the high-cost gas.

Buyer Protection Clauses

The price effect of oil parity redetermination clauses, and indirectly of three-party most favored nation clauses that the oil parity clauses would trigger, can be at least partially mitigated by buyer protection clauses in some gas contracts. Buyer protection clauses are contract clauses that permit the buyer (often a pipeline) to reduce the price of gas. There are several types of buyer

TABLE D-3

FREQUENCY OF OIL PARITY AND MINIMUM PRICE PROVISIONS IN GAS CONTRACTS
CONTAINING DEREGULATION PROVISIONS IN 1980, BY NGPA CATEGORY

Gas Designation under NGPA	Quantity of Gas Sold under a Deregulation Provision in 1980 (Quadrillion Btu)	Gas Sold under an Oil Parity Provision as a Percentage of Gas Sold under a Deregulation Provision	Gas Sold under a Minimum Price Specified as a Percentage of Gas Sold under a Deregulation Provision
Section 104/106(a)	4.13	12	50
Section 105/106(b)	3.37	1	N/A
Section 102	1.67	28	49
Section 103	1.45	14	20
Section 107	0.44	24	20
Section 108	0.12	6 ^a	19

Source: Energy Information Administration, op. cit., tables ES2, 2, and 11

^aResults are based on five or less sample units.

N/A means "not available."

protection clauses. One type allows the pipeline to reduce the price of gas if it is disallowed by the appropriate regulatory agency. The price of gas would then be whatever the regulatory commission allows. As shown in table D-4, such regulatory disallowance clauses are not uncommon. However, these clauses will have little or no effect after the wellhead price controls are lifted and gas is deregulated, because the FERC does not have authority under the NGPA to disallow the automatic pass-through of the gas cost, unless fraud, abuse, or similar grounds can be shown.

Market-out clauses and maximum price provisions are more likely to be effective as buyer protection clauses. Market-out clauses provide an escape for the pipeline if the gas is not marketable at its contract price. If the pipeline exercises its market-out option, it notifies the producer and quotes a price at which it is willing to accept the gas. Then, depending upon how the market-out clause is written, the producer can either accept the new price, cancel the contract, or solicit third-party offers and provide the pipeline with a right of first refusal to buy the gas at any offered higher price. Six percent of the old interstate and interstate rollover contract gas was sold under contracts with market-out provisions in 1980, while 14 percent of the old intrastate and intrastate rollover gas was sold under contracts with market-out clauses. Sixteen and 17 percent of the section 102 and section 103 new gas, respectively, was sold under contracts with market-out clauses. Fully 57 percent of all high-cost gas was sold under contracts with market-out clauses.

Maximum price provisions act as a cap on how high a deregulated price can go. While these clauses are generally less common than regulatory disallowance or market-out clauses, 49 percent of the high-cost gas was sold in 1980 under contracts with maximum price provisions.

TABLE D-4

FREQUENCY OF BUYER PROTECTION CLAUSES IN GAS CONTRACTS CONTAINING
DEREGULATION PROVISIONS IN 1980, BY NGPA CATEGORY

Gas Designation under NGPA	Quantity of Gas Sold under a Deregulation Provision in 1980 (Quadrillion Btu)	Gas Sold under a Market-Out Clause as a Percentage of Gas Sold under a Deregulation Provision	Gas Sold under a Regulatory Disallowance Clause as a Percentage of Gas Sold under a Deregulation Provision	Gas Sold under a Maximum Price Clause as a Percentage of Gas Sold under a Deregulation Provision
Section 104/106(a)	4.13	6	14	8
Section 105/106(b)	3.37	14	N/A	8
Section 102	1.67	16	20	6
Section 103	1.45	17	20	3
Section 107	0.44	57	25	49
Section 108	0.12	7	40	9

Source: Energy Information Administration, op. cit., tables ES2, 2, and 11

N/A means "not available."

Take-or-Pay Provisions and Contract Length

Another type of contractual provision commonly found in producer-pipeline contracts is a take-or-pay provision. Take-or-pay provisions are provisions in contracts between a pipeline and a producer whereby the pipeline agrees to pay the producer for a specified percentage of the gas under contract regardless of whether the gas is taken. As shown in table D-5, take-or-pay provisions were written into gas contracts for all vintages of gas at least through 1980. The volume weighted average of all old interstate gas contract take-or-pay requirements was 92 percent in 1980. For intrastate gas contracts, take-or-pay requirements were highest (94 percent) in those contracts entered into after the oil embargo but before the speech announcing the National Energy Plan by President Carter, delivered on April 20, 1977. After that speech, the take-or-pay required percentages in new gas contracts dropped somewhat. The percentage requirements in new gas contracts dropped a bit further after the enactment of the NGPA. By 1980, new gas contracts had a volume weighted average percentage take-or-pay requirement of 79 percent. There is some reason to believe that there have been further drops in the percentage take-or-pay requirements entered into after 1980.

The take-or-pay percentages are not uniform across contracts for different categories of gas. In 1980, the volume weighted average take-or-pay requirement was lowest for section 107 high-cost gas (75.8 percent) and for old intrastate and intrastate rollover contract gas (75.9 percent). Stripper well gas and old interstate and interstate rollover gas had the highest: 97.8 percent and 92 percent, respectively. The high take-or-pay percentages in old interstate and interstate rollover contracts is probably because much of this gas is gas associated with oil, requiring high takes of gas along with oil production.

TABLE D-5

AVERAGE TAKE-OR-PAY REQUIREMENTS
BY NGPA CATEGORY AND VINTAGE

<u>NGPA Category</u>	<u>Volume Weighted Average of Percentage Take-or-Pay Requirements</u>
Section 104/106(a)	92.0
Section 105/106(b)	75.9
Section 102 Onshore	87.2
Section 102 Offshore	90.4
Section 103	80.1
Section 107	75.8
Section 108	97.8
<u>Vintage^a</u>	
Pre-1973 Intrastate Gas	78.1
1973 to April 20, 1977 Intrastate Gas	94.0
April 20, 1977 - November 8, 1978	88.0
November 8, 1978 - 1979	86.8
1980	79.0

Source: Energy Information Administration, op. cit., table 13

^aData on interstate gas before April 20, 1977 are not available.

It is worth emphasizing that the average take-or-pay percentage of all new gas contracts is greater than that of high-cost gas contracts alone. One possible reason why gas producers are willing to accept lower required takes in high-cost gas contracts may be that, since most high-cost gas is now deregulated, they are able to bargain for a high price in lieu of a favorable contract clause. All categories of new gas, on the other hand, are regulated, so that the producers cannot bargain for any price higher than the applicable NGPA ceiling price; instead, they bargain for higher required takes.

Certain trends can be observed in the length of the term of gas contracts. As shown in table D-6, gas contracts entered into before the enactment of the NGPA tended to have contract terms of twenty years or more. After the enactment of the NGPA, however, the duration of new contracts tended to drop. The contracts covering a majority of the gas sold under a contract entered into between November 9, 1978 and the end of 1979 had a term of less than twenty years. By 1980, the typical contract often had a contract term of less than fifteen years.

TABLE D-6

PERCENTAGE OF GAS CONTRACTS BY
LENGTH OF CONTRACT TERM AND BY CONTRACT VINTAGE

Contract Vintage	Quantity of Gas Sold under Contract in 1980 (Quadrillion Btu)	Percentage of 1980 Quantity Sold with a Contract Term of Less Than 10 Years	Percentage of 1980 Quantity Sold with a Contract Term of 10-14 Years	Percentage of 1980 Quantity Sold with a Contract Term of 15-19 Years	Percentage of 1980 Quantity Sold with a Contract Term of 20 Years or More
Pre-1973	6.69	2.9	1.7 ^a	9.6	85.8
Jan. 1, 1973 to April 20, 1977	1.42	6.7	36.4	2.2	54.8
April 21, 1977 to Nov. 8, 1978	2.34	19.2	12.8	4.1	63.9
Nov. 9, 1978 to Dec. 31, 1979	1.05	19.1	22.5	30.1	28.3
1980	.96	35.2	32.5	25.0	7.3
All Vintages	12.46	10.3	11.9	10.7	67.2

Source: Energy Information Administration, op. cit., table 14, which is based upon Form EIA-758

^aResults are based on five or less sampling units.

APPENDIX E

THE DISTRIBUTION UTILITY COST MODEL COMPUTER PROGRAM

This appendix describes briefly some technical specifications of the computer program containing the NRRI Distribution Utility Cost Model presented in chapter 6. It covers the structure of the main program, called MAIN, and the seven subroutines, called INPUT, DEMAND, FILE, ALOC, ALOC1, WRITE, and REPORT. This appendix also contains a FORTRAN listing of the program.

Program Structure

The computer code has a main program with seven subroutines. The structure of the main program and the subroutines is described in this section. This description is written with the assumption that the reader is already familiar with the program's purposes and methods presented in chapter 6.

MAIN Program

The MAIN program directs the seven subroutines. It has two processing modes: calibration mode and sensitivity analysis mode. In the calibration mode, the program asks the user to enter a pair of weighting factors for commercial and industrial customers. The objective of the calibration mode is to reproduce the burner-tip prices for the three customer classes as close as possible to the observed prices by adjusting the weighting factors. Once the calibration is done, the program asks the user to update the weighting factors. In the sensitivity analysis mode, the user has the following options: (a) to choose the cost allocation method--either the average-and-excess demand method or the peak responsibility method, (b) to assign some fraction of the industrial costs to the residential and commercial sectors, and (c) to change the value of the rate of return. The flow chart E-1 shows this sequence of calculations.

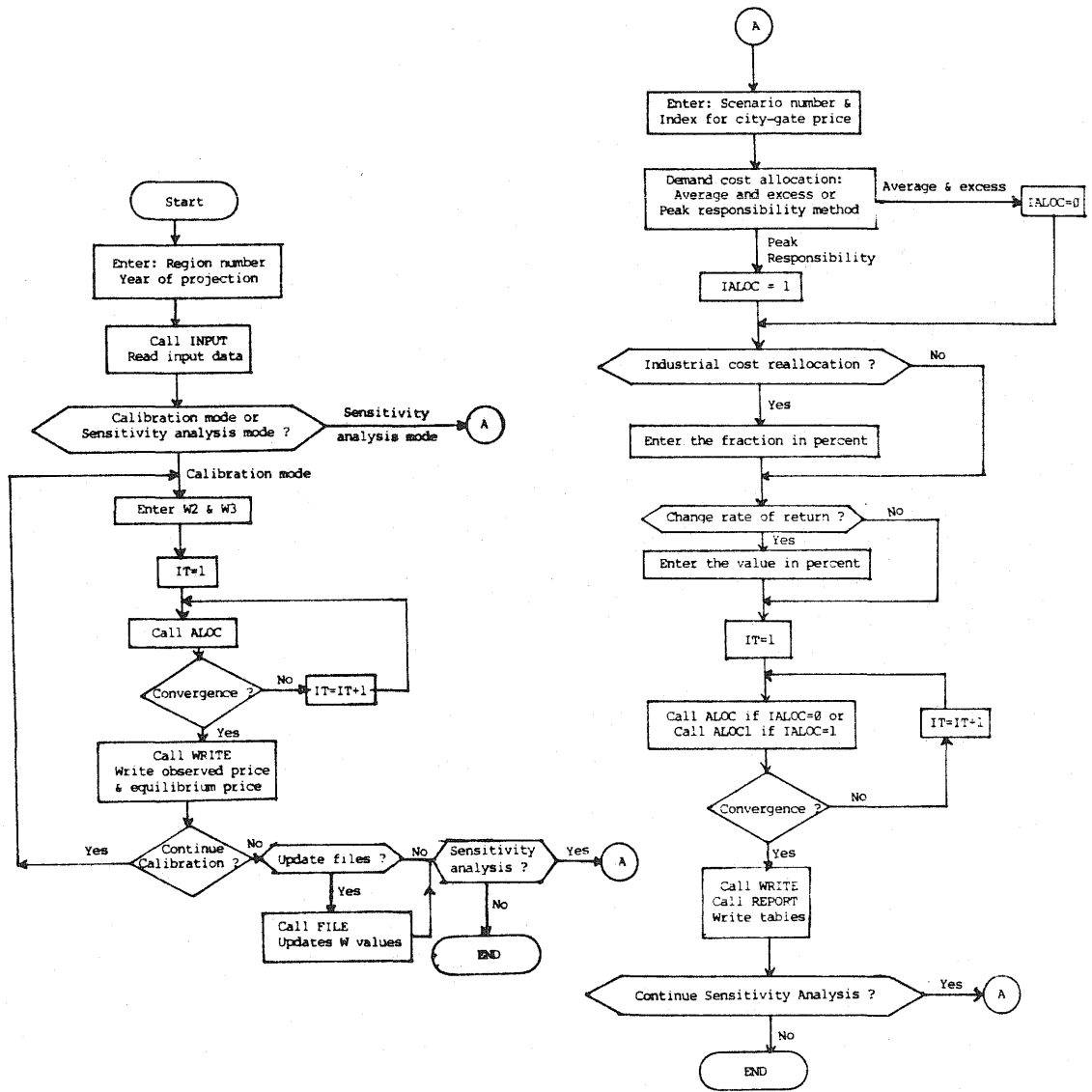


Figure E-1 Flowchart of the distribution utility cost model

INPUT(IRUN) Subroutine

The subroutine INPUT reads most of the input variables required to run the model. The other variables are supplied by the user through the terminal in the interactive mode and by the input file named USER.DATA in the batch mode. This subroutine reads the variables from the input file named REGION.DATA.

DEMAND Subroutine

The DEMAND subroutine calculates gas demands for the three customer classes as functions of the prices of natural gas and other competing fuels and the corresponding elasticities.

ALOC Subroutine

The ALOC subroutine allocates operating costs, plant in service, and taxes to the different customer classes, and finally calculates the burner-tip prices. In this subroutine all calculations are based on the average-and-excess method for allocating capacity costs.

ALOC1 Subroutine

The ALOC1 subroutine calculates the same quantities as subroutine ALOC, but with the peak responsibility method for allocating capacity costs.

FILE Subroutine

The FILE subroutine updates the input file after the calibration phase. In the calibration mode, the only variables that are updated by calling the FILE subroutine are W2 and W3, the weighting factors for commercial and industrial customers, respectively.

WRITE Subroutine

In the calibration mode, the WRITE subroutine writes the observed and model-predicted burner-tip prices for the three customer classes. This subroutine also writes the city-gate price, total expenses, depreciation, taxes, return on rate base per unit (mcf) of natural gas, along with burner-tip prices and the demands of the three customer classes. In the sensitivity analysis mode, this subroutine writes a cost-of-service table, which was used to generate most of the tables presented in chapter 6.

REPORT Subroutine

In the sensitivity analysis mode, the REPORT subroutine writes two tables, Income Statement and Rate Base Allocation, which were used as a basis for preparing some of the results presented in chapter 6.

Description of Input Files

NAME.DATA

Each record contains the name of a region. The format is 20A4.

REGION.DATA

The first record includes the weights for commercial and industrial customers, with the format 2F5.1. Each of the other records contains one variable with the format E15.8. The list of the input variables with their definitions is given below.

<u>Record</u>	<u>Variable</u>	<u>Definition</u>
1	W2, W3	Weights for the commercial and industrial customers
2	LF	Load factor
3	R	Rate of return
4	PPGAS	City-gate price of gas

<u>Record</u>	<u>Variable</u>	<u>Definition</u>
5	K(1)	Coefficient related to monthly residential peak
6	K(2)	Coefficient related to monthly commercial peak
7	K(3)	Coefficient related to monthly industrial peak
8	CSOMO	Storage O & M expenses
9	CDOMO	Distribution O & M expenses
10	CTOMO	Transmission O & M expenses
11	CA00	Customer accounts expenses
12	CS00	Customer services expenses
13	SA00	Sales expenses
14	AG0	Administrative & general expenses
15	TQ0	Combined total demand
16	TPQ0	System non-coincident peak
17	MGPO	Manufacturing gas production plant in service
18	NGPO	Natural gas production plant in service
19	STPO	Storage plant in service
20	TRPO	Transmission plant in service
21	DPO	Distribution plant in service
22	GPO	General plant in service
23	ADJ	Adjustment factor for depreciation
24	DEPO	Depreciation expenses
25	RVTO	Combined revenue taxes
26	PRTO	Property taxes
27	RVO	Combined revenues
28	INCTXO	Income taxes
29	PO(1)	Burner-tip price for residential customers
30	PO(2)	Burner-tip price for commercial customers
31	PO(3)	Burner-tip price for industrial customers
32	NO(1)	Number of residential customers
33	NO(2)	Number of commercial customers
34	NO(3)	Number of industrial customers
35	C(1)	Constant in the residential gas demand function

<u>Record</u>	<u>Variable</u>	<u>Definition</u>
36	C(2)	Constant in the commercial gas demand function
37	C(3)	Constant in the industrial gas demand function
38	E1(1)	Elasticity for residential natural gas
39	E1(2)	Elasticity for commercial natural gas
40	E1(3)	Elasticity for industrial natural gas
41	E2(1)	Elasticity for residential electricity
42	E2(2)	Elasticity for commercial electricity
43	E2(3)	Elasticity for industrial electricity
44	E3(3)	Elasticity for industrial distillate fuel
45	E4(3)	Elasticity for industrial residual fuel
46	E5(3)	Elasticity for industrial liquefied gas
47	E6(3)	Elasticity for industrial coal
48	RPEL	Residential price for electricity
49	CPEL	Commercial price for electricity
50	IPEL	Industrial price for electricity
51	IPDF	Industrial price for distillate fuel
52	IPRF	Industrial price for residual fuel
53	IPLG	Industrial price for liquefied gas
54	IPCL	Industrial price for coal

Operational Procedure

The program can be executed in both the interactive and batch modes. In the interactive mode, the program requires two input data files. One is REGION.DATA, which is under logical unit 10, and the other is NAME.DATA, which is under logical unit 11, as shown in the CLIST required to run the run the program interactively:

```

FREE F(FT10F001,FT11F001)
ALLOC DA(TS3090.REGION.DATA) F(FT10F001)
ALLOC DA(TS3090.NAME.DATA) F(FT11F001) SHR
LOADGO TS3090.GAS.OBJ FORTLIB

```

In the batch mode, the user response is supplied by an additional input file called USER.DATA. The following JCL is used to run the program in batch mode.

```
//JOB
/*JOBPARM L=4000,D=5000
//S1 EXEC PROC=FTGILG
//LKED.SYSIN DD DSN=GAS.OBJ,DISP=SHR
//FT10F001 DD DSN=TS3090.REGION.DATA,DISP=SHR
//FT11F001 DD DSN=TS3090.NAME.DATA,DISP=SHR
//FT05F001 DD DSN=TS3090.USER.DATA,DISP=SHR
//FT06F001 DD SYSOUT=A,DCB=(RECFM=FB,LRECL=133,BLKSIZE=665)
```



```

REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL
C
REAL W2, W3
C
COMMON /FIRST/  N, N0, INCTX0, MGP0, NGP0, NTNQ
COMMON /ZERO/   Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+              CA00, CS00, SA00, AG0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
DOUBLE PRECISION Q, D, T1, T2, T3, C, P0, CSOM0,
+              CA00, CS00, SA00, AG0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0
COMMON /ONE/    P(3), TXJ(3), B(3), F(3), TN
DOUBLE PRECISION P, TXJ, B, F, TN
COMMON /TWO/    E1(3), E2(3), E3(3), E4(3), E5(3), E6(3), K
COMMON /THREE/  W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
COMMON /FOUR/   IT, EPS, R, SCD
COMMON /FIVE/   ADJ, RPEL, RINDEX
COMMON /SIX/    PCAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+              TYK, ALPHA
COMMON /EIGHT/  IRNUM, ISNUM, IYEAR
COMMON /TEN/    PPCAS
COMMON /ELEVEN/ IRUN
DOUBLE PRECISION DEL
C
DATA YES/3HYES/, Y/3HY /
INAME=11
DO 9 I=1,10
1013 READ(INAME,1013) (RCNAME(I,J),J=1,6)
9     FORMAT(6A4)
C     CONTINUE
C
C     FLAG (IRUN) FOR DIFFERENT MODEL PROCESSING MODE
C
WRITE(6,1000)
1000 FORMAT(1X,'ENTER REGION NUMBER')
READ *, IRNUM
WRITE(6,1012)
1012 FORMAT(1X,'ENTER THE YEAR OF PROJECTION IN FOUR DIGITS')
READ *, IYEAR
ITER=0
IALOC=0
WRITE(6,1001)
READ(5,1002) IRUN
IF(IRUN.EQ.0) WRITE(6,1003)
IF(IRUN.EQ.1) WRITE(6,1004)
1001 FORMAT(//2X,'THIS MODEL HAS TWO PROCESSING MODES :'/
12X,'THE CALIBRATION MODE AND THE SENSITIVITY ANALYSIS MODE'/
23X,'ENTER 0 TO INITIATE THE CALIBRATION MODE'/
33X,'ENTER 1 TO INITIATE THE SENSITIVITY ANALYSIS MODE'//)
1002 FORMAT(I1)
1003 FORMAT(/2X,'*****'/
12X,'MODEL CALIBRATION'/
22X,'*****'//)
1004 FORMAT(/2X,'*****'/
12X,'SENSITIVITY ANALYSIS'/
22X,'*****'//)
C
C
C     READ INPUT DATA

```

```

C      CALL INPUT(IRUN)
C
C      IF(IRUN.LE.0) IPASS=1
C
C      2 CONTINUE
C
C      INITIALIZATION OF F & N
C
C      PGAS=PPGAS
C      DO 10 I=1,3
C      N(I)=N0(I)
C      F(I)=P0(I)
10 CONTINUE
IT=0
C
C
C      IF(IRUN.GE.1) GO TO 11
C      IF(ITER.LE.0) CAL=YES
C      IF(ITER.LE.0) GO TO 12
C
C      CONTINUATION OF CALIBRATION PROCESS ?
C
C      WRITE(6,1005)
C      READ(5,1009) CAL
C      IF(CAL.NE.YES.AND.CAL.NE.Y) GO TO 13
1005 FORMAT(//3X,'WOULD YOU LIKE TO CONTINUE THE CALIBRATION PROCESS ?
+ ')
1009 FORMAT(A3)
C
C      INPUT NEW SET OF W
C
C      12 WRITE(6,1007)
1007 FORMAT(//3X,'ENTER VALUES OF W2 AND W3')
READ(5,*) W2,W3
GO TO 17
C
C      END OF MODEL CALIBRATION MODE
C
C      13 CONTINUE
C
C      UPDATE THE INPUT FILE
C
C      WRITE(6,3006)
3006 FORMAT(/5X,'DO YOU WANT TO UPDATE THE W VALUES ?'/
+5X,' IF YES, ENTER YES OR Y'/)
READ(5,1009) WFLAG
IF(WFLAG.NE.YES.AND.WFLAG.NE.Y) GO TO 11
WRITE(6,3007)
3007 FORMAT(/5X,'ENTER THE VALUES OF W TO BE UPDATED'/)
READ *,W2,W3
CALL FILE
11 IF(ITER.LE.0.AND.IRUN.GE.1) GO TO 15
WRITE(6,1008)
READ(5,1009) FLAG
IF(FLAG.NE.YES.AND.FLAG.NE.Y) GO TO 3
IF(IRUN.GE.1) GO TO 15
WRITE(6,1004)

```

```

        IRUN= 1
        ITER=0
15 CONTINUE
C
C      CHANGE OF THE CITY GATE PRICE
C
        WRITE(6,3009)
3009  FORMAT(3X,'ENTER THE SCANARIO NUMBER')
        READ *, ISNUM
        WRITE(6,3008)
3008  FORMAT(1X,'ENTER THE INDEX FOR GAS PRICE')
        READ *, RINDEX
        PGAS=PPGAS*RINDEX
1008  FORMAT(//3X,'WOULD YOU LIKE TO CONTINUE WITH THE SENSITIVITY ANALY
+SIS ?')
C
C      OPTION FOR COST ALLOCATION
C
        WRITE(6,2010)
2010  FORMAT(/3X,'OPTION FOR DEMAND COSTS ALLOCATION'//
*3X,'ENTER 0 TO USE AVERAGE & EXCESS METHOD'//
*9X,'1 TO USE PEAK RESPONSIBILITY METHOD')
        READ(5,1002) IALOC
        IZ3=0
        WRITE(6,2001)
2001  FORMAT(/3X,'WOULD YOU LIKE TO CONSIDER ASSIGNING SOME FRACTION OF
+THE'/3X,'INDUSTRIAL COSTS DIRECTLY TO THE RESIDENTIAL & COMMERCIAL
+'/3X,'SECTORS ? (YES/NO) ')
        READ(5,1009) RES
        IPASS=1
        IF(RES.EQ.YES.OR.RES.EQ.Y) IPASS=2
        IF(IPASS.LE.1) GO TO 18
        WRITE(6,2002)
2002  FORMAT(/4X,'ENTER THAT FRACTION IN PERCENT ')
        READ (5,*) IZ3
C
C      CHANGE OF RATE OF RETURN
C
C
18  CONTINUE
        R=R*100.0
        WRITE(6,2004) R
2004  FORMAT(//3X,'THE RATE OF RETURN PREVIOUSLY USED IS ',F6.3,'%'/
+3X,'IF YOU WANT TO CHANGE THIS VALUE, ENTER THE VALUE IN PERCENT'/
+3X,'OTHERWISE, ENTER 0')
        READ *, VALUE
        IF(VALUE.GT.0.0) R=VALUE
        WRITE(6,2005) R
2005  FORMAT(//3X,'THE RATE OF RETURN IS ',F6.3,'%')//
        R=R*.01
C
17  CONTINUE
        N(2)=N(2)*W2
        N(3)=N(3)*W3
        TN=N(1)+N(2)+N(3)
14  WRITE(6,1011) W2,W3
1011  FORMAT(//5X,'W2 = ',F5.1,'      W3 = ',F5.1//)
1  CONTINUE
C
C      ITERATION FOR EQUILIBRIUM STARTS HERE

```



```

C      IT=IT+1
      DO 5 I=1,3
      P(I)=F(I)
5      CONTINUE
C
      CALL DEMAND
C
      IF(IALOC.LE.0) CALL ALOC
      IF(IALOC.GE.1) CALL ALOC1
C
C      CONVERGENCE CRITERION
C
      DO 20 I=1,3
      DEL=DABS((F(I)-P(I))/P(I))
      IF(DEL.GE.EPS) GO TO 1
20     CONTINUE
C
      CALL DEMAND
C
      IF(CAL.NE.YES.AND.CAL.NE.Y) GO TO 21
      WRITE(6,2006)
2006   FORMAT(//10X,'ORIGINAL PRICE',10X,'PRICE AFTER CON',
+ 'VERGENCE'//)
      DO 22 I=1,3
      WRITE(6,2007) I,P(I),F(I)
2007   FORMAT(//5X,'P(',I1,')',5X,F6.3,15X,F6.3)
22     CONTINUE
C
      21 CALL WRITE(RCNAME)
      IF(IRUN.EQ.1) CALL REPORT(RCNAME)
C
      ITER=ITER+1
      GO TO 2
3      STOP
      END
C
C      =====
      SUBROUTINE INPUT(IRUN)
      =====
C
C      THIS SUBROUTINE SUPPLIES THE INPUT VALUES
C
C      =====
C
C      ACO      : ADMINSTRATIVE AND GENERAL
C      ADJ      : ADJUSTMENT FOR DEPRECIATION
C      CSOM0    : STORAGE 0 3 M
C      CDOM0    : DISTRIBUTION 0 3 M
C      CTOM0    : TRANSMISSION 0 3 M
C      CA00     : CUSTOMER ACCOUNTS
C      CS00     : CUSTOMER SALES
C      C        : CONSTANT FOR DEMAND FUNCTION
C      CPHEL    : COMMERCIAL PRICE FOR ELECTRICITY
C      DP0      : DISTRIBUTION PLANT
C      DEP0     : DEPRECIATION EXPENSE
C      E1       : ELASTICITY FOR GAS

```

```

C      E2      : ELASTICITY FOR ELECTRICITY
C      E3      : ELASTICITY FOR DISTILLATE FUEL
C      E4      : ELASTICITY FOR RESIDUAL FUEL
C      E5      : ELASTICITY FOR LIQUEFIED GAS
C      IPEL     : INDUSTRIAL PRICE FOR ELECTRICITY
C      IPDF     : INDUSTRIAL PRICE FOR DISTILLATE FUEL
C      IPRF     : INDUSTRIAL PRICE FOR RESIDUAL FUEL
C      IPLG     : INDUSTRIAL PRICE FOR LIQUEFIED GAS
C      IPCL     : INDUSTRIAL PRICE FOR COAL
C      INCTX0   : INCOME TAXES
C      GP0      : GENERAL PLANT IN SERVICE
C      K        : COEFFICIENT WHEN MULTIPLIED BY DEMAND GIVES MONTHLY PEAK
C      LF       : LOAD FACTOR
C      MCP0     : MANUFACTURING PLANT
C      NGP0     : NATURAL GAS PRODUCTION PLANTS
C      N0       : INITIAL NUMBER OF CUSTOMERS
C      P0       : INITIAL EQUILIBRIUM PRICE FOR GAS
C      PRT0     : PROPERTY TAXES
C      R        : RATE OF RETURN
C      RPEL     : RESIDENTIAL PRICE FOR ELECTRICITY
C      RV0      : COMBINED REVENUE
C      RVT0     : COMBINED REVENUE TAXES
C      SA00     : SALES EXPENSES
C      STP0     : STORAGE PLANT INVESTMENT
C      TQ0      : COMBINED INITIAL DEMAND
C      TP00     : COMBINED SYSTEM NONCOINCIDENCE PEAK
C      TRP0     : TRANSPORTATION PLANT IN SERVICE
C      W2       : WEIGHT FOR COMMERCIAL CUSTOMER
C      W3       : WEIGHT FOR RESIDENTIAL CUSTOMER

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C=====
C
C

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REAL*8 N(3), N0(3), INCTX0, MCP0, NGP0, NTNQ(3)
REAL K(3), X(11,3), ALPHA(3)
REAL NUM(3), BETA(3), GAMMA(3), TYK(3)
REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL

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REAL W2, W3

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COMMON /FIRST/  N, N0, INCTX0, MCP0, NGP0, NTNQ
COMMON /ZERO/   Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+              CA00, CS00, SA00, AC0, TQ0, TP00, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
DOUBLE PRECISION Q, D, T1, T2, T3, C, P0, CSOM0,
+              CA00, CS00, SA00, AC0, TQ0, TP00, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0
COMMON /ONE/    P(3), TXJ(3), B(3), F(3), TN
DOUBLE PRECISION P, TXJ, B, F, TN
COMMON /TWO/    E1(3), E2(3), E3(3), E4(3), E5(3), E6(3), K
COMMON /THREE/  W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
COMMON /FOUR/   IT, EPS, R, SCD
COMMON /FIVE/   ADJ, RPEL, RINDEX
COMMON /SIX/    PGAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+              TYK, ALPHA
COMMON /TEN/    PPGAS

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C      IFILE=10

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EPS= .001
SCD= .44
READ(IFILE, 1000) W2, W3
READ(IFILE, 1001) LF
READ(IFILE, 1001) R
READ(IFILE, 1001) PPGAS

C
C

READ(IFILE, 1001) K(1)
READ(IFILE, 1001) K(2)
READ(IFILE, 1001) K(3)

C
C

READ(IFILE, 1001) CSOM0
READ(IFILE, 1001) CBOM0
READ(IFILE, 1001) CTOM0
READ(IFILE, 1001) CA00
READ(IFILE, 1001) CS00
READ(IFILE, 1001) SA00
READ(IFILE, 1001) AG0
READ(IFILE, 1001) T00
READ(IFILE, 1001) TP00
READ(IFILE, 1001) MGP0
READ(IFILE, 1001) NGP0
READ(IFILE, 1001) STP0
READ(IFILE, 1001) TRP0
READ(IFILE, 1001) DP0
READ(IFILE, 1001) GP0
READ(IFILE, 1001) ADJ
READ(IFILE, 1001) DEP0
READ(IFILE, 1001) RVT0
READ(IFILE, 1001) RV0
READ(IFILE, 1001) PRT0
READ(IFILE, 1001) INCTX0
READ(IFILE, 1001) P0(1)
READ(IFILE, 1001) P0(2)
READ(IFILE, 1001) P0(3)
READ(IFILE, 1001) N0(1)
READ(IFILE, 1001) N0(2)
READ(IFILE, 1001) N0(3)
READ(IFILE, 1001) C(1)
READ(IFILE, 1001) C(2)
READ(IFILE, 1001) C(3)
READ(IFILE, 1001) E1(1)
READ(IFILE, 1001) E1(2)
READ(IFILE, 1001) E1(3)
READ(IFILE, 1001) E2(1)
READ(IFILE, 1001) E2(2)
READ(IFILE, 1001) E2(3)
READ(IFILE, 1001) E3(3)
READ(IFILE, 1001) E4(3)
READ(IFILE, 1001) E5(3)
READ(IFILE, 1001) E6(3)
READ(IFILE, 1001) RPEL
READ(IFILE, 1001) CPEL
READ(IFILE, 1001) IPEL
READ(IFILE, 1001) IPDF
READ(IFILE, 1001) IPRF
READ(IFILE, 1001) IPLG
READ(IFILE, 1001) IPCL


```

C      T1      : REVENUE TAXES
C      T2      : PROPERTY TAXES
C      T3      : INCOME TAXES
C      TXJ     : TOTAL EXPENSES
C      TYK     : TOTAL PLANTS IN SERVICE
C      X       : EXPENSE COMPONENT
C      Y       : PLANT COMPONENT
C      Z1      : FRACTION OF RESIDENTIAL DEMAND WITH RESPECT TO COMBINED
C              RESIDENTIAL AND COMMERCIAL DEMAND
C      Z3      : FRACTION OF INDUSTRIAL COST SHARED BY COMMERCIAL
C              & INDUSTRIAL CUSTOMERS

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C      REAL*8 N(3), N0(3), INCTX0, MGP0, NGP0, NTNQ(3)
C      REAL K(3), X(11,3), ALPHA(3), Y(10,3)
C      REAL NUM(3), BETA(3), GAMMA(3), TYK(3)
C      REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL
C      REAL KQ, KQ1, KQ2

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C      REAL W2, W3

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C      COMMON /FIRST/  N, N0, INCTX0, MGP0, NGP0, NTNQ
C      COMMON /ZERO/   Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+                    CA00, CS00, SA00, AC0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+                    CDOM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
C      DOUBLE PRECISION Q, D, T1, T2, T3, C, P0, CSOM0,
+                    CA00, CS00, SA00, AC0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+                    CDOM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0
C      COMMON /ONE/    P(3), TXJ(3), B(3), F(3), TN
C      DOUBLE PRECISION P, TXJ, B, F, TN
C      COMMON /TWO/    E1(3), E2(3), E3(3), E4(3), E5(3), E6(3), K
C      COMMON /THREE/  W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
C      COMMON /FOUR/   IT, EPS, R, SCD
C      COMMON /FIVE/   ADJ, RPEL, RINDEX
C      COMMON /SIX/    PGAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+                    TYK, ALPHA
C      COMMON /SEVEN/  Y

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C      O & M ALLOCATION

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```

C      TQ=0.0
C      TQ2=0.0
C      DO 20 J=1,3
C      TQ=TQ+Q(J)
C      TQ2=TQ2+K(J)*Q(J)-Q(J)/12.
20    CONTINUE
C      DO 10 I=1,3
C      X(1,I)=(CSOM0/TQ2)*(1.0-LF)*(K(I)-1.0/12.0)
C      X(2,I)=(CSOM0/TQ)*LF
C      X(3,I)=(CTOM0/TQ2)*(1.0-LF)*(K(I)-1.0/12.0)
C      X(4,I)=(CTOM0/TQ)*LF
C      X(5,I)=(CDOM0/TN)*SCD*N(I)*1.0/Q(I)
C      X(6,I)=(CDOM0/TQ2)*(1.0-SCD)*(1-LF)*(K(I)-1./12.)
C      X(7,I)=(CDOM0/TQ)*LF*(1.0-SCD)
C      NTNQ(I)=N(I)/(TN*Q(I))

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X(8, I) = CA00 * NTNQ( I )
X(9, I) = CS00 * NTNQ( I )
X(10, I) = SA00 * NTNQ( I )
NUM( I ) = 0.0
DO 30 J = 1, 10
30 NUM( I ) = NUM( I ) + X( J, I )
CONTINUE
NUM( I ) = NUM( I ) * Q( I )
10 CONTINUE
DEN = 0.0
DO 40 L = 1, 3
40 DEN = DEN + NUM( L )
CONTINUE
DO 11 I = 1, 3
ALPHA( I ) = NUM( I ) / DEN
X(11, I) = ( AG0 / TQ0 ) * ALPHA( I ) * TQ / Q( I )
11 CONTINUE
KQ = 0.0
KQ1 = 0.0
DO 60 J = 1, 3
KQ1 = KQ1 + K( J ) * Q( J )
KQ = KQ + K( J ) * Q( J ) - Q( J ) / 12.0
60 CONTINUE
DO 50 I = 1, 3
Y(1, I) = MGP0 * ADJ * K( I ) / KQ1
Y(2, I) = NGP0 * ADJ / TQ
Y(3, I) = ( STP0 * ADJ ) * ( 1.0 - LF ) * ( K( I ) - 1.0 / 12. ) / KQ
Y(4, I) = ( STP0 * ADJ ) * LF / TQ
Y(5, I) = ( TRP0 * ADJ ) * ( 1.0 - LF ) * ( K( I ) - 1. / 12. ) / KQ
Y(6, I) = ( TRP0 * ADJ ) * LF / TQ
Y(7, I) = ( DP0 * ADJ ) * SCD * NTNQ( I )
Y(8, I) = ( DP0 * ADJ ) * ( 1.0 - SCD ) * ( 1.0 - LF ) * ( K( I ) - 1. / 12. ) / KQ
Y(9, I) = ( DP0 * ADJ ) * ( 1.0 - SCD ) * LF / TQ
50 CONTINUE
DO 55 I = 1, 3
NUM( I ) = 0.0
DO 70 J = 1, 9
70 NUM( I ) = NUM( I ) + Y( J, I )
CONTINUE
NUM( I ) = NUM( I ) * Q( I )
55 CONTINUE
DEN = 0.0
DO 80 L = 1, 3
80 DEN = DEN + NUM( L )
CONTINUE
DO 81 I = 1, 3
BETA( I ) = NUM( I ) / DEN
X(10, I) = ( GP0 * ADJ ) * BETA( I ) / Q( I )
81 CONTINUE
IF ( IPASS.EQ.1 ) GO TO 18
Z1 = Q( 1 ) / ( Q( 1 ) + Q( 2 ) )
Z3 = IZ3 / 100.0
DO 16 J = 1, 11
16 X( J, 1 ) = ( X( J, 1 ) * Q( 1 ) + Z1 * Z3 * X( J, 3 ) * Q( 3 ) ) / Q( 1 )
X( J, 2 ) = ( X( J, 2 ) * Q( 2 ) + ( 1.0 - Z1 ) * Z3 * X( J, 3 ) * Q( 3 ) ) / Q( 2 )
X( J, 3 ) = X( J, 3 ) * ( 1.0 - Z3 )
CONTINUE
DO 17 J = 1, 10
Y( J, 1 ) = ( Y( J, 1 ) * Q( 1 ) + Z1 * Z3 * Y( J, 3 ) * Q( 3 ) ) / Q( 1 )
Y( J, 2 ) = ( Y( J, 2 ) * Q( 2 ) + ( 1.0 - Z1 ) * Z3 * Y( J, 3 ) * Q( 3 ) ) / Q( 2 )

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17      Y(J,3)=Y(J,3)*(1.0-Z3)
18      CONTINUE
19      CONTINUE
20      DO 82 I=1,3
21          RB(I)=0.0
22      DO 90 J=1,10
23          RB(I)=RB(I)+Y(J,I)
90      CONTINUE
24          RB(I)=RB(I)*Q(I)
82      CONTINUE
25          TRB=0.0
26      DO 100 J=1,3
27          TRB=TRB+RB(J)
100     CONTINUE
28          DO 105 I=1,3
29              GAMMA(I)=RB(I)/TRB
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31      C
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890     C
891     C
892     C
893     C
894     C
895     C
896     C
897     C
898     C
899     C
900     C
901     C
902     C
903     C
904     C
905     C
906     C
907     C
908     C
909     C
910     C
911     C
912     C
913     C
914     C
915     C
916     C
917     C
918     C
919     C
920     C
921     C
922     C
923     C
924     C
925     C
926     C
927     C
928     C
929     C
930     C
931     C
932     C
933     C
934     C
935     C
936     C
937     C
938     C
939     C
940     C
941     C
942     C
943     C
944     C
945     C
946     C
947     C
948     C
949     C
950     C
951     C
952     C
953     C
954     C
955     C
956     C
957     C
958     C
959     C
960     C
961     C
962     C
963     C
964     C
965     C
966     C
967     C
968     C
969     C
970     C
971     C
972     C
973     C
974     C
975     C
976     C
977     C
978     C
979     C
980     C
981     C
982     C
983     C
984     C
985     C
986     C
987     C
988     C
989     C
990     C
991     C
992     C
993     C
994     C
995     C
996     C
997     C
998     C
999     C
1000    C

```



```

C
C
C ALPHA : TEMPORARY VARIABLE USED FOR CALCULATION
C BETA : TEMPORARY VARIABLE USED FOR CALCULATION
C B : RETURN ON RATE BASE
C CSOM0 : STORAGE 0 8 M
C CDOM0 : STRIBUTION 0 8 M
C CTOM0 : TRANSMISSION 0 8 M
C DEN : TEMPORARY VARIABLE USED FOR CALCULATION
C D : DEPRECIATION
C DP0 : DISTRIBUTION PLANT INVESTMENT
C F : PRICE OF GAS AT N TH ITERATION
C GAMMA : TEMPORARY VARIABLE USED FOR CALCULATION
C VAL :
C KQ :
C LF : LOAD FACTOR
C MGP0 : MANUFACTURING PLANT INVESTMENT
C NCP0 : NATURAL GAS PRODUCTION PLANT INVESTMENT
C N : NUMBER OF CUSTOMERS
C NTNQ : TEMPORARY VARIABLE USED FOR CALCULATION
C NUM : TEMPORARY VARIABLE USED FOR CALCULATION
C PCAS : PRICE OF GAS AT CITY GATE
C Q : DEMAND OF GAS
C RB : RATE BASE
C SCD :
C STP0 : STORAGE PLANT INVESTMENT
C TRP0 : TRANSMISSION PLANT INVESTMENT
C TQ : COMBINED DEMAND OF GAS
C TP00 :
C TQ0 :
C TN : COMBINED NUMBER OF CUSTOMERS
C TRB : COMBINED RATE BASE
C T1 : REVENUE TAXES
C T2 : PROPERTY TAXES
C T3 : INCOME TAXES
C TXJ : TOTAL EXPENSES
C TYK : TOTAL PLANTS IN SERVICE
C X : EXPENSE COMPONENT
C Y : PLANT COMPONENT

```

```

C-----
C
C

```

```

REAL*8 N(3), N0(3), INCTX0, MGP0, NCP0, NTNQ(3)
REAL K(3), X(11,3), ALPHA(3), Y(10,3)
REAL NUM(3), BETA(3), GAMMA(3), TYK(3)
REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL
REAL KQ, KQ1, KQ2

```

```

REAL W2, W3

```

```

COMMON /FIRST/ N, N0, INCTX0, MGP0, NCP0, NTNQ
COMMON /ZERO/ Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+ CA00, CS00, SA00, AG0, TQ0, TP00, STP0, DP0, GP0, DEP0,
+ CDOM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
DOUBLE PRECISION Q, D, T1, T2, T3, C, P0, CSOM0,
+ CA00, CS00, SA00, AG0, TQ0, TP00, STP0, DP0, GP0, DEP0,
+ CDOM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0

```

```

COMMON /ONE/      P(3),TXJ(3),B(3),F(3),TN
DOUBLE PRECISION P, TXJ, B, F, TN
COMMON /TWO/      E1(3),E2(3),E3(3),E4(3),E5(3),E6(3),K
COMMON /THREE/    W2,W3,LF,IPEL,IPDF,IPRF,IPLG,IPCL
COMMON /FOUR/     IT,EPS,R,SCD
COMMON /FIVE/     ADJ,RPPEL,RINDEX
COMMON /SIX/      PGAS,IPASS,Z1,IZ3,CPEL,X,NUM,BETA,GAMMA,
+                TYK,ALPHA
COMMON /SEVEN/    Y

```

C
C
C
C

O & M ALLOCATION

```

TQ=0.0
KQ2=0.0
DO 20 J=1,3
TQ=TQ+Q(J)
KQ2=KQ2+K(J)*Q(J)
20 CONTINUE
DO 10 I=1,3
X(1,I)=CSOM0/KQ2*K(I)
X(2,I)=0.0
X(3,I)=(CTOM0/KQ2)*K(I)
X(4,I)=0.0
X(5,I)=(CDOM0/TN)*SCD*N(I)*1.0/Q(I)
X(6,I)=(CDOM0/KQ2)*(1.0-SCD)*K(I)
X(7,I)=0.0
NTNQ(I)=N(I)/(TN*Q(I))
X(8,I)=CA00*NTNQ(I)
X(9,I)=CS00*NTNQ(I)
X(10,I)=SA00*NTNQ(I)
NUM(I)=0.0
DO 30 J=1,10
NUM(I)=NUM(I)+X(J,I)
30 CONTINUE
NUM(I)=NUM(I)*Q(I)
10 CONTINUE
DEN=0.0
DO 40 L=1,3
DEN=DEN+NUM(L)
40 CONTINUE
DO 11 I=1,3
ALPHA(I)=NUM(I)/DEN
X(11,I)=(AC0/TQ0)*ALPHA(I)*TQ/Q(I)
11 CONTINUE
KQ1=0.0
DO 60 J=1,3
KQ1=KQ1+K(J)*Q(J)
60 CONTINUE
DO 50 I=1,3
Y(1,I)=MGP0*ADJ*K(I)/KQ1
Y(2,I)=NGP0*ADJ/TQ
Y(3,I)=(STP0*ADJ)*K(I)/KQ1
Y(4,I)=0.0
Y(5,I)=(TRP0*ADJ)*K(I)/KQ1
Y(6,I)=0.0
Y(7,I)=(DP0*ADJ)*SCD*NTNQ(I)
Y(8,I)=(DP0*ADJ)*(1.0-SCD)*K(I)/KQ1
Y(9,I)=0.0
50 CONTINUE

```

```

DO 55 I=1,3
NUM(I)=0.0
DO 70 J=1,9
NUM(I)=NUM(I)+Y(J,I)
70 CONTINUE
NUM(I)=NUM(I)*Q(I)
55 CONTINUE
DEN=0.0
DO 80 L=1,3
DEN=DEN+NUM(L)
80 CONTINUE
DO 81 I=1,3
BETA(I)=NUM(I)/DEN
Y(10,I)=(GP0*ADJ)*BETA(I)/Q(I)
81 CONTINUE
IF (IPASS.EQ.1) GO TO 18
Z1=Q(1)/(Q(1)+Q(2))
Z3=IZ3/100.0
DO 16 J=1,11
X(J,1)=(X(J,1)*Q(1)+Z1*Z3*X(J,3)*Q(3))/Q(1)
X(J,2)=(X(J,2)*Q(2)+(1.0-Z1)*Z3*X(J,3)*Q(3))/Q(2)
X(J,3)=X(J,3)*(1.0-Z3)
16 CONTINUE
DO 17 J=1,10
Y(J,1)=(Y(J,1)*Q(1)+Z1*Z3*Y(J,3)*Q(3))/Q(1)
Y(J,2)=(Y(J,2)*Q(2)+(1.0-Z1)*Z3*Y(J,3)*Q(3))/Q(2)
Y(J,3)=Y(J,3)*(1.0-Z3)
17 CONTINUE
18 CONTINUE
DO 82 I=1,3
RB(I)=0.0
DO 90 J=1,10
RB(I)=RB(I)+Y(J,I)
90 CONTINUE
RB(I)=RB(I)*Q(I)
82 CONTINUE
TRB=0.0
DO 100 J=1,3
TRB=TRB+RB(J)
100 CONTINUE
DO 105 I=1,3
GAMMA(I)=RB(I)/TRB

C
C DEPRECIATION
C
C D(I)=DEP0*GAMMA(I)/Q(I)
C
C REVENUE TAXES
C
C T1(I)=RVT0*P(I)/RV0
C
C PROPERTY TAXES
C
C T2(I)=PRT0*GAMMA(I)/Q(I)
C
C INCOME TAXES
C
C T3(I)=INCTX0*GAMMA(I)/Q(I)
C
C FINAL CALCULATION

```

```

C
TXJ(I)=0.0
DO 110 J=1,11
TXJ(I)=TXJ(I)+X(J,I)
110 CONTINUE
TYK(I)=0.0
DO 120 L=1,10
TYK(I)=TYK(I)+Y(L,I)
120 CONTINUE
B(I)=R*TYK(I)
F(I)=PGAS+TXJ(I)+D(I)+T1(I)+T2(I)+T3(I)+B(I)
105 CONTINUE
RETURN
END

```

```

C
C
C
=====
SUBROUTINE FILE
=====

```

```

C
C
C
THIS SUBROUTINE UPDATES THE INPUT FILE (FT10F001) TO INCLUDE
THE CALIBRATION RESULTS
C
C
C
=====

```

```

C
C
C
AC0      : ADMINSTRATIVE AND GENERAL
C
ADJ      : ADJUSTMENT FOR DEPRECIATION
C
CSOM0    : STORAGE 0 & M
C
CDOM0    : DISTRIBUTION 0 & M
C
CTOM0    : TRANSMISSION 0 & M
C
CA00     : CUSTOMER ACCOUNTS
C
CS00     : CUSTOMER SALES
C
C        : CONSTANT FOR DEMAND FUNCTION
C
CPEL     : COMMERCIAL PRICE FOR ELECTRICITY
C
DPO      : DISTRIBUTION PLANT
C
DEP0     : DEPRECIATION EXPENSE
C
E1       : ELASTICITY FOR GAS
C
E2       : ELASTICITY FOR ELECTRICITY
C
E3       : ELASTICITY FOR DISTILLATE FUEL
C
E4       : ELASTICITY FOR RESIDUAL FUEL
C
E5       : ELASTICITY FOR LIQUEFIED GAS
C
IPEL     : INDUSTRIAL PRICE FOR ELECTRICITY
C
IPDF     : INDUSTRIAL PRICE FOR DISTILLATE FUEL
C
IPRF     : INDUSTRIAL PRICE FOR RESIDUAL FUEL
C
IPLG     : INDUSTRIAL PRICE FOR LIQUEFIED GAS
C
IPCL     : INDUSTRIAL PRICE FOR COAL
C
INCTX0   : INCOME TAXES
C
GPO      : GENERAL PLANT IN SERVICE
C
K        : COEFFICIENT WHEN MULTIPLIED BY DEMAND GIVES MONTHLY PEAK
C
LF       : LOAD FACTOR
C
MCP0     : MANUFACTURING PLANT
C
NGPO     : NATURAL GAS PRODUCTION PLANTS
C
N0       : INITIAL NUMBER OF CUSTOMERS
C
P0       : INITIAL EQUILIBRIUM PRICE FOR GAS
C
PRT0     : PROPERTY TAXES
C
R        : RATE OF RETURN
C
RPEL     : RESIDENTIAL PRICE FOR ELECTRICITY
C
RV0      : COMBINED REVENUE

```

```

C   RVT0   : COMBINED REVENUE TAXES
C   SA00   : SALES EXPENSES
C   STP0   : STORAGE PLANT INVESTMENT
C   TQ0    : COMBINED INITIAL DEMAND
C   TPQ0   : COMBINED SYSTEM NONCOINCIDENCE PEAK
C   TRP0   : TRANSPORTATION PLANT IN SERVICE
C   W2     : WEIGHT FOR COMMERCIAL CUSTOMER
C   W3     : WEIGHT FOR RESIDENTIAL CUSTOMER

```

```

C   =====
C

```

```

REAL*8 N(3), N0(3), INCTX0, MGP0, NGP0, NTNQ(3)
REAL K(3), X(11,3), ALPHA(3)
REAL NUM(3), BETA(3), GAMMA(3), TYK(3)
REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL

```

```

REAL W2, W3

```

```

COMMON /FIRST/  N, N0, INCTX0, MGP0, NGP0, NTNQ
COMMON /ZERO/   Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+              CA00, CS00, SA00, AC0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
DOUBLE PRECISION Q, D, T1, T2, T3, C, P0, CSOM0,
+              CA00, CS00, SA00, AC0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDOM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0
COMMON /ONE/    P(3), TXJ(3), B(3), F(3), TN
DOUBLE PRECISION P, TXJ, B, F, TN
COMMON /TWO/   E1(3), E2(3), E3(3), E4(3), E5(3), E6(3), K
COMMON /THREE/ W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
COMMON /FOUR/  IT, EPS, R, SCD
COMMON /FIVE/  ADJ, RPEL, RINDEX
COMMON /SIX/   PGAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+             TYK, ALPHA
COMMON /TEN/   PPCAS

```

```

IFILE=10
REWIND IFILE
WRITE(IFILE,1000) W2, W3
WRITE(IFILE,1001) LF
WRITE(IFILE,1001) R
WRITE(IFILE,1001) PPCAS

```

```

WRITE(IFILE,1001) K(1)
WRITE(IFILE,1001) K(2)
WRITE(IFILE,1001) K(3)

```

```

WRITE(IFILE,1001) CSOM0
WRITE(IFILE,1001) CDOM0
WRITE(IFILE,1001) CTOM0
WRITE(IFILE,1001) CA00
WRITE(IFILE,1001) CS00
WRITE(IFILE,1001) SA00
WRITE(IFILE,1001) AC0

```



```

C      ADJ      :
C      B       : RETURN ON RATE BASE PER MCF
C      CSOM0   : STORAGE 0 8 M
C      CDOM0   : DISTRIBUTION 0 8 M
C      CTOM0   : TRANSMISSION 0 8 M
C      CAOM0   : CUSTOMER ACCOUNTS
C      CS00    : CUSTOMER SALES
C      C       : CONSTANT FOR DEMAND FUNCTION
C      CPTEL   : COMMERCIAL PRICE FOR ELECTRICITY
C      D       : DEPRECIATION
C      DP0     : DISTRIBUTION PLANT
C      DEPO    : DEPRECIATION EXPENSE
C      F       : BURNER TIP PRICE OF GAS
C      IT      : ITERATION NUMBER
C      IRNUM   : REGION NUMBER
C      ISNUM   : SCENARIO NUMBER
C      IYEAR   : YEAR OF PROJECTION
C      K       : COEFFICIENT WHEN MULTIPLIED BY DEMAND GIVES MONTHLY PEAK
C      LF      : LOAD FACTOR
C      MCP0    : MANUFACTURING PLANT
C      NCP0    : NATURAL GAS PRODUCTION PLANTS
C      N0      : INITIAL NUMBER OF CUSTOMERS
C      PCAS    : CITY GATE PRICE
C      P0      : INITIAL EQUILIBRIUM PRICE FOR GAS
C      PRT0    : PROPERTY TAXES
C      R       : RATE OF RETURN
C      RPEL    : RESIDENTIAL PRICE FOR ELECTRICITY
C      RV0     : COMBINED REVENUE
C      RVT0    : COMBINED REVENUE TAXES
C      SA00    : SALES EXPENSES
C      STP0    : STORAGE PLANT INVESTMENT
C      TXJ     : TOTAL EXPENSES PER MCF
C      T1      : REVENUE TAX PER MCF
C      T2      : PROPERTY TAX PER MCF
C      T3      : INCOME TAX PER MCF
C      TTXJ    : TOTAL EXPENSE COMPONENT IN PERCENT
C      TD      : DEPRECIATION COMPONENT IN PRICE IN PERCENT
C      TT1     : REVENUE TAX COMPONENT IN PRICE IN PERCENT
C      TT2     : PROPERTY TAX COMPONENT IN PRICE IN PERCENT
C      TT3     : INCOME TAX COMPONENT IN PRICE IN PERCENT
C      TQ0     : COMBINED INITIAL DEMAND
C      TB      : RETURN ON RATE BASE COMPONENT IN PRICE IN PERCENT
C      TPQ0    : COMBINED SYSTEM NONCOINCIDENCE PEAK
C      W2      : WEIGHT FOR COMMERCIAL CUSTOMER
C      W3      : WEIGHT FOR RESIDENTIAL CUSTOMER

```

```

C-----
C
C      DIMENSION TPGAS(3), TTXJ(3), TD(3), TT1(3), TT2(3), TT3(3), TB(3), TOT(3)
C      +, TEMPQ(3), RGNAME(10,6), ITEMPQ(3)
C      REAL*8 N(3), N0(3), INCTX0, MCP0, NCP0, NTNQ(3)
C      REAL K(3), X(11,3), ALPHA(3)
C      REAL NUM(3), BETA(3), GAMMA(3), TYK(3)
C      REAL LF, IPEL, IPDF, IPRF, IPLG, IPCL
C
C      REAL W2, W3
C
C

```

```

COMMON /FIRST/  N, N0, INCTX0, MCP0, NGP0, NTINQ
COMMON /ZERO/   Q(3), D(3), T1(3), T2(3), T3(3), C(3), P0(3), CSOM0,
+              CA00, CS00, SA00, AG0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDM0, PRT0, RV0, RVT0, RB(3), CTOM0, TRP0
DOUBLE PRECISION  Q, D, T1, T2, T3, C, P0, CSOM0,
+              CA00, CS00, SA00, AG0, TQ0, TPQ0, STP0, DP0, GP0, DEP0,
+              CDM0, PRT0, RV0, RVT0, RB, CTOM0, TRP0
COMMON /ONE/     P(3), TXJ(3), B(3), F(3), TN
DOUBLE PRECISION P, TXJ, B, F, TN
COMMON /TWO/    E1(3), E2(3), E3(3), E4(3), E5(3), E6(3), K
COMMON /THREE/  W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
COMMON /FOUR/   IT, EPS, R, SCF
COMMON /FIVE/   ADJ, RPEL, RINDEX
COMMON /SIX/    PGAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+              TYK, ALPHA
COMMON /EIGHT/  IRNUM, ISNUM, IYEAR
COMMON /ELEVEN/ IRUN

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C

```

WRITE(6,1001) IT
1001 FORMAT(//5X, 'THE SOLUTION CONVERGES AT ITERATION NUMBER ', I3//)
WRITE(6,9002) PGAS, PCAS, PCAS
9002 FORMAT(3(7X, 'PGAS=' , E10.4 ))
WRITE(6,9003) ( I, TXJ(I), I=1, 3)
9003 FORMAT(7X, 'TXJ(' , I1, ')=' , E10.4, 2(5X, 'TXJ(' , I1, ')=' , E10.4))
WRITE(6,9004) ( I, D(I), I=1, 3)
9004 FORMAT(3(7X, 'D(' , I1, ')=' , E10.4))
WRITE(6,9005) ( I, T1(I), I=1, 3)
9005 FORMAT(7X, 'T1(' , I1, ')=' , E10.4, 2(6X, 'T1(' , I1, ')=' , E10.4))
WRITE(6,9006) ( I, T2(I), I=1, 3)
9006 FORMAT(7X, 'T2(' , I1, ')=' , E10.4, 2(6X, 'T2(' , I1, ')=' , E10.4))
WRITE(6,9007) ( I, T3(I), I=1, 3)
9007 FORMAT(7X, 'T3(' , I1, ')=' , E10.4, 2(6X, 'T3(' , I1, ')=' , E10.4))
WRITE(6,9008) ( I, B(I), I=1, 3)
9008 FORMAT(3(7X, 'B(' , I1, ')=' , E10.4))
WRITE(6,9009) ( I, F(I), I=1, 3)
9009 FORMAT(3(7X, 'F(' , I1, ')=' , E10.4))
WRITE(6,9013) ( I, Q(I), I=1, 3)
9013 FORMAT(3(7X, 'Q(' , I1, ')=' , E10.4))
IF(IRUN.LE.0) GO TO 99
DO 19 I=1, 3
TPCAS(I)=PGAS*100.0/F(I)
TTXJ(I)=TXJ(I)*100.0/F(I)
TD(I)=D(I)*100.0/F(I)
TT1(I)=T1(I)*100.0/F(I)
TT2(I)=T2(I)*100.0/F(I)
TT3(I)=T3(I)*100.0/F(I)
TB(I)=B(I)*100.0/F(I)
TOT(I)=100.0
19 CONTINUE
WRITE(6,9014)
9014 FORMAT(1H1)
IF(ISNUM.EQ.0) GO TO 31
WRITE(6,9025) IYEAR
9025 FORMAT(/////35X, 'REGIONAL CUSTOMER IMPACTS ANALYSIS' /
+38X, 'PROJECTION FOR THE YEAR', I5/)
31 CONTINUE
IF(ISNUM.EQ.0) WRITE(6,5020)
5020 FORMAT(/////35X, 'REGIONAL CUSTOMER IMPACTS ANALYSIS' /
+38X, 'BASE YEAR (1980) STUDY' /)
WRITE(6,5018) IRNUM, (RCNAME(IRNUM, J), J=1, 6)

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5018  FORMAT(34X,'REGION',I3,' : ',15A4)
      IF(ISNUM.EQ.1) WRITE(6,5014)
5014  FORMAT(/34X,'SCENARIO : ICF STUDY - EXTENDED NGPA'/
+46X,'DOE 1981 ANNUAL REPORT TO CONGRESS')
      IF(ISNUM.EQ.2) WRITE(6,5015)
5015  FORMAT(/34X,'SCENARIO : EIA STUDY - NGPA PRICING POLICY'/
+46X,'EIA STUDY - IMMEDIATE TOTAL DECONTROL')
      IF(ISNUM.EQ.3) WRITE(6,5016)
5016  FORMAT(/34X,'SCENARIO : AGA STUDY - OPTIMISTIC CONTRACTS',
+ ' SCENARIO'/46X,' ICF STUDY - ACCELERATE NGPA TO 1982')
      IF(ISNUM.EQ.4) WRITE(6,5017)
5017  FORMAT(/34X,'SCENARIO : ICF STUDY - IMMEDIATE TOTAL DECONTROL')
      IF(ISNUM.EQ.0) GO TO 98
      WRITE(6,9035) RINDEX
9035  FORMAT(46X,'(1985/1980 CITY GATE PRICE INDEX : ',F4.2,' )')
98    CONTINUE
      WRITE(6,5019) IZ3
5019  FORMAT(/25X,14,'% INDUSTRIAL COSTS REALLOCATED TO RESIDENTIAL',
+ ' AND COMMERCIAL CUSTOMERS'/)
      WRITE(6,9026)
9026  FORMAT(/39X,'COST OF SERVICE ANALYSIS')
      WRITE(6,9027)
9027  FORMAT(39X,'-----')
      WRITE(6,9031)
9031  FORMAT(/15X'-----',
+ '-----')
      WRITE(6,9016)
9016  FORMAT(15X,'DESCRIPTION',26X,'RESIDENTIAL',7X,'COMMERCIAL',6X,
+ ' INDUSTRIAL')
      WRITE(6,9017)
9017  FORMAT(15X,'-----',26X,'-----',7X,'-----',6X,
+ '-----')
      WRITE(6,9034)
      WRITE(6,9028) PGAS,PGAS,PGAS
9028  FORMAT(/15X,'CITY GATE PRICE (1980 $/MCF)',13X,3(F5.2,12X)
      WRITE(6,9029) (F(1),I=1,3)
9029  FORMAT(/15X,'BURNER TIP PRICE (1980 $/MCF)',12X,3(F5.2,12X)
      DO 10 I=1,3
      TEMPQ(I)=Q(I)*.001
      ITEMPQ(I)=TEMPQ(I)
10    CONTINUE
      WRITE(6,9030) (ITEMPQ(I),I=1,3)
9030  FORMAT(/15X,'DEMAND (MMCF)',19X,3(F14,3X)
      WRITE(6,9034)
9034  FORMAT(/15X,81(' '))
      WRITE(6,9032)
9032  FORMAT(/15X,'BURNER TIP PRICE : COST COMPOSITION IN PERCENT'/)
      WRITE(6,9018) (TPGAS(I),I=1,3)
9018  FORMAT(/18X,'CITY GATE PRICE (%)',19X,3(F5.2,12X)
      WRITE(6,9019) (TTXJ(I),I=1,3)
9019  FORMAT(/18X,'O & M EXPENSES (%)',20X,3(F5.2,12X)
      WRITE(6,9020) (TD(I),I=1,3)
9020  FORMAT(/18X,'DEPRECIATION EXPENSES (%)',13X,3(F5.2,12X)
      WRITE(6,9021) (TT1(I),I=1,3)
9021  FORMAT(/18X,'REVENUE TAXES(%)',22X,3(F5.2,12X)
      WRITE(6,9022) (TT2(I),I=1,3)
9022  FORMAT(/18X,'PROPERTY TAXES (%)',20X,3(F5.2,12X)
      WRITE(6,9023) (TT3(I),I=1,3)
9023  FORMAT(/18X,'INCOME TAXES (%)',22X,3(F5.2,12X)
      WRITE(6,9024) (TB(I),I=1,3)

```

```

9024 FORMAT(/18X, 'RETURN ON RATE BASE (%)', 15X, 3(F5.2, 12X))
      WRITE(6, 9033) (TOT(I), I=1, 3)
9033 FORMAT(/15X, 'TOTAL (%)', 31X, 3(F6.2, 11X))
      WRITE(6, 9031)
99    CONTINUE
      RETURN
      END

```

```

C
C
C=====
      SUBROUTINE REPORT(RCNAME)
C=====

```

```

C
C
C      THIS SUBROUTINE DOES THE NECESSARY CALCULATIONS FOR REPORT AND
C      WRITES THE REPORT
C
C=====

```

```

C
C
C      ADPIS : PLANT VALUE IN SERVICE AFTER DEPRECIATION
C      AE    : ADMINISTRATIVE EXPENSES
C      CA    : EXPENSES FOR CUSTOMER ACCOUNTS
C      CS    : EXPENSES FOR CUSTOMER SERVICES
C      DOM   : DISTRIBUTION EXPENSES FOR O & M
C      DE    : DEPRECIATION EXPENSES
C      DR    : DEPRECIATION RESERVE
C      DPIS  : DEPRECIATION PLANT IN SERVICE
C      IRNUM : REGION NUMBER
C      ISNUM : SCENARIO NUMBER
C      IYEAR : YEAR OF PROJECTION
C      F     : PRICE OF GAS IN (N-1) TH ITERATION
C      OR    : OPERATING REVENUE
C      OE    : OPERATING EXPENSES
C      P     : PRICE OF GAS IN N TH ITERATION
C      PCG   : VALUE OF GAS AT CITY GATE
C      PT    : PROPERTY TAXES
C      PPIS  : PRODUCTION PLANT IN SERVICE
C      Q     : DEMAND FOR GAS
C      RT    : REVENUE TAXES
C      RIT   : INCOME TAXES
C      RNOI  : NET OPERATING INCOME
C      RBF   : RATE BASE VALUE
C      RRB   : RETURN ON RATE BASE
C      RNPIS : VALUE OF NET PLANT IN SERVICE
C      RMPIS : MANUFACTURING PLANT IN SERVICE
C      RIPIS : INTANGIBLE PLANT IN SERVICE
C      SOM   : STORAGE EXPENSE FOR O & M
C      SE    : SALES EXPENSES
C      SPIS  : STORAGE PLANT IN SERVICE
C      TROM  : TRANSMISSION EXPENSES
C      TRPIS : TRANSMISSION PLANT IN SERVICE
C      TOR   : COMBINED OPERATING REVENUE
C      TPCC  : COMBINED VALUE OF GAS AT CITY GATE
C      TSOM  : COMBINED STORAGE EXPENSES FOR O & M
C      TDOM  : COMBINED DISTRIBUTION EXPENSES FOR O & M
C      TCA   : COMBINED EXPENSES FOR CUSTOMER ACCOUNTS
C      TCS   : COMBINED EXPENSES FOR CUSTOMER SERVICES
C      TSE   : COMBINED SALES EXPENSES

```



```

COMMON /THREE/ W2, W3, LF, IPEL, IPDF, IPRF, IPLG, IPCL
COMMON /FOUR/ IT, EPS, R, SCD
COMMON /FIVE/ ADJ, RPEL, RINDEX
COMMON /SIX/ PGAS, IPASS, Z1, IZ3, CPEL, X, NUM, BETA, GAMMA,
+ TYK, ALPHA
COMMON /SEVEN/ Y
COMMON /EIGHT/ IRNUM, ISNUM, IYEAR

```

C
C

```

TRMPIS=0.0
TPPIS=0.0
TSPIS=0.0
TADPIS=0.0
TDPIS=0.0
TRIPIS=0.0
TTPIS=0.0
TTRPIS=0.0
TTROM=0.0
TRNPIS=0.0
TRBF=0.0
TOR=0.0
TPCG=0.0
TSOM=0.0
TDOM=0.0
TCA=0.0
TCS=0.0
TSE=0.0
TAE=0.0
TDE=0.0
TRT=0.0
TPT=0.0
TRIT=0.0
TOE=0.0
TRNOI=0.0
TRRB=0.0
TCWIP=0.00
TWC=0.00
TDR=0.0
DO 5 I=1,3
CWIP(I)=0.0
WC(I)=0.0
DR(I)=0.0
CONTINUE

```

5
C
C
C

CALCULATION OF THE VALUE OF PLANT IN SERVICE

```

DO 10 I=1,3
RMPIS(I)=Y(1, I)*Q(I)/ADJ
TRMPIS=TRMPIS+RMPIS(I)
PPIS(I)=Y(2, I)*Q(I)/ADJ
TPPIS=TPPIS+PPIS(I)
SPIS(I)=(Y(3, I)+Y(4, I))*Q(I)/ADJ
TSPIS=TSPIS+SPIS(I)
TRPIS(I)=(Y(5, I)+Y(6, I))*Q(I)/ADJ
TTRPIS=TTRPIS+TRPIS(I)
DPIS(I)=(Y(7, I)+Y(8, I)+Y(9, I))*Q(I)/ADJ
TDPIS=TDPIS+DPIS(I)
RIPIS(I)=Y(10, I)*Q(I)/ADJ
TRIPIS=TRIPIS+RIPIS(I)
TPIS(I)=RMPIS(I)+PPIS(I)+SPIS(I)+DPIS(I)+RIPIS(I)+TRPIS(I)

```

TTPIS=TPIS+TPIS(I)
 ADPIS(I)=(Y(1,I)+Y(2,I)+Y(3,I)+Y(4,I)+Y(5,I)+Y(6,I)+Y(7,I)+
 +Y(8,I)+Y(9,I)+Y(10,I))*Q(I)
 TADPIS=TADPIS+ADPIS(I)

C
C

CLACULATION OF OPERAATING REVENUE

OR(I)=F(I)*Q(I)
 TOR=TOR+OR(I)

C
C
C

CALCULATION OF OPERATING EXPENSES

PCG(I)=PGAS*Q(I)
 TPCG=TPCG+PCG(I)
 SOM(I)=(X(1,I)+X(2,I))*Q(I)
 TSOM=TSOM+SOM(I)
 TROM(I)=(X(3,I)+X(4,I))*Q(I)
 TTROM=TTROM+TROM(I)
 DOM(I)=(X(5,I)+X(6,I)+X(7,I))*Q(I)
 TDOM=TDOM+DOM(I)
 CA(I)=X(8,I)*Q(I)
 TCA=TCA+CA(I)
 CS(I)=X(9,I)*Q(I)
 TCS=TCS+CS(I)
 SE(I)=X(10,I)*Q(I)
 TSE=TSE+SE(I)
 AE(I)=X(11,I)*Q(I)
 TAE=TAE+AE(I)
 DE(I)=D(I)*Q(I)
 TDE=TDE+DE(I)
 RT(I)=T1(I)*Q(I)
 TRT=TRT+RT(I)
 PT(I)=T2(I)*Q(I)
 TPT=TPT+PT(I)
 RIT(I)=T3(I)*Q(I)
 TRIT=TRIT+RIT(I)
 OE(I)=PCG(I)+SOM(I)+TROM(I)+DOM(I)+CA(I)+CS(I)+SE(I)+
 +AE(I)+DE(I)+RT(I)+PT(I)+RIT(I)
 TOE=TOE+OE(I)

C
C
C

CALCULATION OF NET OPERATING INCOME

RNOI(I)=OR(I)-OE(I)
 TRNOI=TRNOI+RNOI(I)

C
C
C

CALCULATION OF DEPRECIATION RESERVE

DR(I)=TPIS(I)-ADPIS(I)
 TDR=TDR+DR(I)

C
C
C

CALCULATION OF RATE BASE

RNPIS(I)=TPIS(I)-DR(I)
 TRNPIS=TRNPIS+RNPIS(I)
 RBF(I)=RNPIS(I)+CWIP(I)+WC(I)
 TRBF=TRBF+RBF(I)

C
C
C

CALCULATION OF RATE OF RETURN

IF(I.EQ.3.AND.RBF(3).LE.0.0) GO TO 7

7
C
C
C

RRB(I)=RNOI(I)*100.0/RBF(I)
CONTINUE

CALCULATION IN TERMS OF THOUSANDS DOLLARS

RMPIS(I)=RMPIS(I)*.001
PPIS(I)=PPIS(I)*.001
SPIS(I)=SPIS(I)*.001
TRPIS(I)=TRPIS(I)*.001
DPIS(I)=DPIS(I)*.001
RIPIS(I)=RIPIS(I)*.001
TPIS(I)=TPIS(I)*.001
ADPIS(I)=ADPIS(I)*.001
OR(I)=OR(I)*.001
PCG(I)=PCG(I)*.001
SOM(I)=SOM(I)*.001
TROM(I)=TROM(I)*.001
DOM(I)=DOM(I)*.001
CA(I)=CA(I)*.001
CS(I)=CS(I)*.001
SE(I)=SE(I)*.001
AE(I)=AE(I)*.001
DE(I)=DE(I)*.001
RT(I)=RT(I)*.001
PT(I)=PT(I)*.001
RIT(I)=RIT(I)*.001
OE(I)=OE(I)*.001
RNOI(I)=RNOI(I)*.001
DR(I)=DR(I)*.001
RNPIS(I)=RNPIS(I)*.001
RBF(I)=RBF(I)*.001

10

CONTINUE
TRMPIS=TRMPIS*.001
TPPIS=TPPIS*.001
TSPIS=TSPIS*.001
TTRPIS=TTRPIS*.001
TDPIS=TDPIS*.001
TRIPIS=TRIPIS*.001
TTPIS=TTPIS*.001
TADPIS=TADPIS*.001
TOR=TOR*.001
TPCG=TPCG*.001
TSOM=TSOM*.001
TTROM=TTROM*.001
TDOM=TDOM*.001
TCA=TCA*.001
TCS=TCS*.001
TSE=TSE*.001
TAE=TAE*.001
TDE=TDE*.001
TRT=TRT*.001
TPT=TPT*.001
TRIT=TRIT*.001
TOE=TOE*.001
TRNOI=TRNOI*.001
TDR=TDR*.001
TRNPIS=TRNPIS*.001
TRBF=TRBF*.001
TRRB=TRNOI*100.0/TRBF

C

```

WRITE(6,4000)
4000 FORMAT(1H1)
IF(ISNUM.EQ.0) GO TO 31
WRITE(6,4024) IYEAR
4024 FORMAT(/////40X,'REGIONAL CUSTOMER IMPACTS ANALYSIS'/
+43X,'PROJECTION FOR THE YEAR',15/)
31 CONTINUE
IF(ISNUM.EQ.0) WRITE(6,5020)
5020 FORMAT(/////35X,'REGIONAL CUSTOMER IMPACTS ANALYSIS'/
+38X,'BASE YEAR (1980) STUDY'/)
WRITE(6,5018) IRNUM,(RNAME(IRNUM,J),J=1,6)
IF(ISNUM.EQ.1) WRITE(6,5014)
5014 FORMAT(/40X,'SCENARIO : ICF STUDY - EXTENDED NGPA'/
+52X,'DOE 1981 ANNUAL REPORT TO CONGRESS')
IF(ISNUM.EQ.2) WRITE(6,5015)
5015 FORMAT(/40X,'SCENARIO : EIA STUDY - NGPA PRICING POLICY'/
+52X,'EIA STUDY - IMMEDIATE TOTAL DECONTROL')
IF(ISNUM.EQ.3) WRITE(6,5016)
5016 FORMAT(/40X,'SCENARIO : AGA STUDY - OPTIMISTIC CONTRACTS',
+' SCENARIO'/52X,'ICF STUDY - ACCELERATE NGPA TO 1982')
IF(ISNUM.EQ.4) WRITE(6,5017)
5017 FORMAT(/40X,'SCENARIO : ICF STUDY - IMMEDIATE TOTAL DECONTROL')
IF(ISNUM.EQ.0) GO TO 98
WRITE(6,5042) RINDEX
5042 FORMAT(52X,'(1985/1980 CITY GATE PRICE INDEX : ',F4.2, ' ')
98 CONTINUE
WRITE(6,5019) IZ3
5019 FORMAT(/25X,14,'% INDUSTRIAL COSTS REALLOCATED TO RESIDENTIAL',
+' AND COMMERCIAL CUSTOMERS'/)
WRITE(6,4001)
4001 FORMAT(/35X,'INCOME STATEMENT (THOUSANDS OF 1980 DOLLARS)')
WRITE(6,4002)
4002 FORMAT(35X,44(' ')/)
WRITE(6,4025)
4025 FORMAT(16X,93(' ')/)
WRITE(6,4003)
4003 FORMAT(16X,'COMPONENT',22X,'TOTAL',11X,'RESIDENTIAL',9X,
+' COMMERCIAL',6X,'INDUSTRIAL')
WRITE(6,4041)
4041 FORMAT(16X,'-----',22X,'-----',11X,'-----',9X,
+'-----',6X,'-----'/)
WRITE(6,4004) TOR,(OR(I),I=1,3)
4004 FORMAT(16X,'OPERATING REVENUES',6X,4('$',F14.2,3X)/)
WRITE(6,4005)
4005 FORMAT(16X,'OPERATING EXPENSES'/16X,'-----')
WRITE(6,4006) TPCG,(PCC(I),I=1,3)
4006 FORMAT(18X,'COST OF GAS PURCHASED',1X,4('$',F14.2,3X))
WRITE(6,4007) TSOM,(SOM(I),I=1,3)
4007 FORMAT(18X,'STORAGE O & M',9X,4('$',F14.2,3X))
WRITE(6,4023) TTROM,(TROM(I),I=1,3)
4023 FORMAT(18X,'TRANSMISSION O & M',4X,4('$',F14.2,3X))
WRITE(6,4008) TDOM,(DOM(I),I=1,3)
4008 FORMAT(18X,'DISTRIBUTION O & M',4X,4('$',F14.2,3X))
WRITE(6,4009) TCA,(CA(I),I=1,3)
4009 FORMAT(18X,'CUSTOMER ACCOUNTS',5X,4('$',F14.2,3X))
WRITE(6,4010) TCS,(CS(I),I=1,3)
4010 FORMAT(18X,'CUSTOMER SERVICES',5X,4('$',F14.2,3X))
WRITE(6,4011) TSE,(SE(I),I=1,3)
4011 FORMAT(18X,'SALES',17X,4('$',F14.2,3X))
WRITE(6,4012) TAE,(AE(I),I=1,3)

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4012 FORMAT(18X, 'ADMINISTRATIVE', 8X, 4('$', F14.2, 3X))
WRITE(6, 4013) TDE, (DE(I), I=1, 3)
4013 FORMAT(18X, 'DEPRECIATION', 10X, 4('$', F14.2, 3X))
WRITE(6, 4014) TRT, (RT(I), I=1, 3)
4014 FORMAT(18X, 'REVENUE TAXES', 9X, 4('$', F14.2, 3X))
WRITE(6, 4015) TPT, (PT(I), I=1, 3)
4015 FORMAT(18X, 'PROPERTY TAXES', 8X, 4('$', F14.2, 3X))
WRITE(6, 4016) TRIT, (RIT(I), I=1, 3)
4016 FORMAT(18X, 'INCOME TAXES', 10X, 4('$', F14.2, 3X))
WRITE(6, 4017)
4017 FORMAT(18X, 20(' '), 2X, 4('-----', 3X))
WRITE(6, 4018) TOE, (OE(I), I=1, 3)
4018 FORMAT(17X, 'TOTAL OPER. EXPENSES', 3X, 4('$', F14.2, 3X) /)
WRITE(6, 4019) TRNOI, (RNOI(I), I=1, 3)
4019 FORMAT(16X, 'NET OPERATING INCOME', 4X, 4('$', F14.2, 3X))
WRITE(6, 4020)
4020 FORMAT(16X, 22('='), 2X, 4('=====', 3X) /)
WRITE(6, 4021) TRBF, (RBF(I), I=1, 3)
4021 FORMAT(16X, 'RATE BASE', 15X, 4('$', F14.2, 3X) /)
IF(RBF(3).LE.0.0) WRITE(6, 4026) TRRB, (RRB(I), I=1, 2)
4026 FORMAT(16X, 'RATE OF RETURN (%)', 6X, 3(F15.2, 3X), 5X, 10(' '))
IF(RBF(3).LE.0.0) GO TO 6
WRITE(6, 4022) TRRB, (RRB(I), I=1, 3)
4022 FORMAT(16X, 'RATE OF RETURN (%)', 6X, 4(F15.2, 3X))
6
CONTINUE
WRITE(6, 4025)
WRITE(6, 4000)
IF(ISNUM.EQ.0) GO TO 32
WRITE(6, 4024) IYEAR
32
CONTINUE
IF(ISNUM.EQ.0) WRITE(6, 5020)
WRITE(6, 5018) IRNUM, (RCNAME(IRNUM, J), J=1, 6)
5018 FORMAT(40X, 'REGION', I3, ' : ', 15A4)
IF(ISNUM.EQ.1) WRITE(6, 5014)
IF(ISNUM.EQ.2) WRITE(6, 5015)
IF(ISNUM.EQ.3) WRITE(6, 5016)
IF(ISNUM.EQ.4) WRITE(6, 5017)
IF(ISNUM.EQ.0) GO TO 97
WRITE(6, 5042) RINDEX
97
CONTINUE
WRITE(6, 5019) IZ3
WRITE(6, 5001)
5001 FORMAT(//35X, 'RATE BASE ALLOCATION (THOUSANDS OF 1980 DOLLARS)'/,
+35X, 48(' '))
WRITE(6, 4025)
WRITE(6, 4003)
WRITE(6, 4041)
WRITE(6, 5041)
5041 FORMAT(16X, 'PLANT IN SERVICE' / 16X, '-----')
WRITE(6, 5002) TRMPIS, (RMPIS(I), I=1, 3)
5002 FORMAT(19X, 'MANUFACTURING PLANT', 2X, 4('$', F14.2, 3X))
WRITE(6, 5003) TPPIS, (PPIS(I), I=1, 3)
5003 FORMAT(19X, 'PRODUCTION PLANT', 5X, 4('$', F14.2, 3X))
WRITE(6, 5004) TSPIS, (SPIS(I), I=1, 3)
5004 FORMAT(19X, 'STORAGE PLANT', 8X, 4('$', F14.2, 3X))
WRITE(6, 5005) TDPIIS, (DPIS(I), I=1, 3)
5005 FORMAT(19X, 'DISTRIBUTION PLANT', 3X, 4('$', F14.2, 3X))
WRITE(6, 5013) TTRPIS, (TRPIS(I), I=1, 3)
5013 FORMAT(19X, 'TRANSMISSION PLANT', 3X, 4('$', F14.2, 3X))
WRITE(6, 5006) TRIPIS, (RIPIS(I), I=1, 3)

```



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5006  FORMAT(19X, 'GENERAL PLANT', 8X, 4('$', F14.2, 3X))
      WRITE(6, 4017)
      WRITE(6, 5007) TTPIS, (TPIS(I), I=1, 3)
5007  FORMAT(17X, 'TOTAL PLANT IN SERVICE', 1X, 4('$', F14.2, 3X) /)
      WRITE(6, 5008) TDR, (DR(I), I=1, 3)
5008  FORMAT(19X, 'DEPRECIATION RESERVE', 1X, 4('$', F14.2, 3X))
      WRITE(6, 4017)
      WRITE(6, 5009) TRNPIS, (RNPIS(I), I=1, 3)
5009  FORMAT(16X, 'NET PLANT IN SERVICE', 4X, 4('$', F14.2, 3X) /)
      WRITE(6, 5010) TCWIP, (CWIP(I), I=1, 3)
5010  FORMAT(19X, 'CWIP', 17X, 4('$', F14.2, 3X))
      WRITE(6, 5011) TWC, (WC(I), I=1, 3)
5011  FORMAT(19X, 'WORKING CAPITAL', 6X, 4('$', F14.2, 3X))
      WRITE(6, 4017)
      WRITE(6, 5012) TRBF, (RBF(I), I=1, 3)
5012  FORMAT(16X, 'RATE BASE', 15X, 4('$', F14.2, 3X))
      WRITE(6, 4025)
      WRITE(6, 4000)
      RETURN
      END

```

APPENDIX F
ADDITIONAL RESULTS PERTAINING TO STATE COST
ALLOCATION POLICY

This appendix contains additional results of the analysis reported in chapter 6 on the effects of commission cost allocation policy. These results are organized into two sections. The first has additional data on the effects on retail rates of using two demand cost allocation methods. The second section contains additional results of the analysis of industrial cost reallocation. It is assumed that the reader is familiar with the discussion in chapter 6 that introduces these data.

Retail Prices Resulting from Two Demand Cost
Allocation Methods

Tables F-1 through F-3 contain projected 1985 retail rates for various increases in city-gate prices, using two demand cost allocation methods: the peak responsibility (PR) method and the average-and-excess demand (AED) method. The expected 1985 city-gate prices are (1) those projected in DOE's 1981 Annual Report to Congress (ARC81) in table F-1, (2) those representing a 75 percent real increase in table F-2, and (3) those representing a 125 percent real increase in table F-3. The results representing a 100 percent real increase in city-gate prices are presented in chapter 6, table 6-24, as representative results.

Results Pertaining to Industrial Cost Reallocation

The effects on expected retail rates and sales of a 50 percent and a 100 percent industrial cost reallocation are presented in tables F-4 through F-9 for various real increases in city-gate prices. Results for city-gate prices as projected in ARC81 are presented in tables F-4 and F-5; results for a 75 percent city-gate price increase in 1985 are presented in tables F-6 and F-7; and results for a 125

TABLE F-1

PROJECTED 1985 RETAIL PRICES USING TWO DEMAND COST
ALLOCATION METHODS WITH CITY-GATE PRICES AS
PROJECTED IN ARC81

Utility's Region	1985 Natural Gas Price (1980 \$/mcf)					
	Residential		Commercial		Industrial	
	AED Method	PR Method	AED Method	PR Method	AED Method	PR Method
N. Eng.	7.13	7.04	6.50	6.56	5.61	5.79
E.N. Centr.	6.47	6.44	5.90	5.90	5.07	5.13
Mid. Atl.	4.08	4.01	4.09	4.05	3.63	3.83
Sou. Atl.	5.94	5.61	4.62	4.58	4.10	4.18
Midwest	4.35	4.32	4.12	4.10	3.97	4.04
Southwest	3.86	3.83	3.63	3.62	3.33	3.32
Central	4.25	4.24	3.91	3.91	3.72	3.73
N. Centr.	5.14	5.10	5.31	5.26	5.01	5.07
West	5.97	5.89	6.23	6.22	6.44	6.32
N. West	6.95	6.89	6.50	6.45	5.94	5.98

Source: NRRI model

TABLE F-2

PROJECTED 1985 RETAIL PRICES USING TWO DEMAND COST
ALLOCATION METHODS WITH A 75 PERCENT REAL INCREASE
IN CITY-GATE PRICES

Utility's Region	1985 Natural Gas Price (1980 \$/mcf)					
	Residential		Commercial		Industrial	
	AED Method	PR Method	AED Method	PR Method	AED Method	PR Method
N. Eng.	8.20	8.11	7.55	7.62	6.75	6.95
E.N. Centr.	7.58	7.56	7.00	6.99	6.14	6.21
Mid. Atl.	4.56	4.51	4.56	4.54	4.27	4.50
Sou. Atl.	6.49	6.19	5.15	5.11	4.63	4.70
Midwest	4.59	4.56	4.35	4.33	4.27	4.34
Southwest	4.16	4.14	3.91	3.91	3.62	3.62
Central	4.59	4.59	4.26	4.25	4.07	4.08
N. Centr.	5.41	5.36	5.57	5.52	5.29	5.35
West	5.57	5.50	5.83	5.82	5.97	5.85
N. West	7.31	7.25	6.86	6.81	6.30	6.34

Source: NRRI model

TABLE F-3

PROJECTED 1985 RETAIL PRICES USING TWO DEMAND COST
ALLOCATION METHODS WITH A 125 PERCENT REAL INCREASE
IN CITY-GATE PRICES

Utility's Region	1985 Natural Gas Price (1980 \$/mcf)					
	Residential		Commercial		Industrial	
	AED Method	PR Method	AED Method	PR Method	AED Method	PR Method
N. Eng.	9.97	9.88	9.29	9.36	8.70	8.93
E.N. Centr.	9.29	9.27	8.67	8.67	7.81	7.88
Mid. Atl.	5.61	5.58	5.61	5.61	5.91	6.25
Sou. Atl.	7.85	7.60	6.47	6.44	5.95	6.02
Midwest	5.67	5.65	5.43	5.41	5.72	5.79
Southwest	5.15	5.14	4.86	4.86	4.60	4.60
Central	5.75	5.75	5.41	5.40	5.23	5.23
N. Centr.	6.84	6.81	7.02	6.98	6.86	6.93
West	7.10	7.03	7.37	7.35	7.87	7.74
N. West	9.12	9.07	8.66	8.62	8.09	8.14

Source: NRRI model

TABLE F-4

PERCENT CHANGE IN RETAIL PRICES DUE TO INDUSTRIAL COST
REALLOCATION FOR CITY-GATE PRICES AS PROJECTED IN ARC81

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	1	1	-9	-1	3	3	-16	-1
E.N. Centr.	2	2	-7	-1	5	5	-13	-2
Mid. Atl.	11	11	-19	-3	27	28	-31	-8
Sou. Atl.	5	6	-4	-1	11	13	-8	-1
Midwest	4	4	-10	-1	8	9	-17	-2
Southwest	27	29	-11	-2	65	71	-20	-3
Central	0	1	-1	0	1	1	-2	0
N. Centr.	8	8	-9	-1	18	18	-16	-2
West	12	11	-9	-1	27	26	-16	-2
N. West	3	3	-2	0	5	6	-4	0

Source: Authors' calculations

TABLE F-5

PERCENT CHANGE IN ANNUAL SALES DUE TO INDUSTRIAL COST
REALLOCATION FOR CITY-GATE PRICES AS PROJECTED IN ARC81

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	0	0	21	3	-1	-1	45	6
E.N. Centr.	-1	-1	19	4	-2	-2	41	9
Mid. Atl.	-3	-4	57	21	-8	-8	122	45
Sou. Atl.	-2	-2	8	4	-4	-4	16	8
Midwest	-1	-1	23	6	-3	-3	47	13
Southwest	-10	-9	16	9	-19	-17	34	19
Central	0	0	2	1	0	0	4	1
N. Centr.	-2	-3	20	9	-5	-6	41	18
West	-4	-4	25	10	-9	-8	52	23
N. West	-1	-1	3	2	-2	-2	7	3

Source: Authors' calculations

TABLE F-6

PERCENT CHANGE IN RETAIL PRICES DUE TO INDUSTRIAL COST
REALLOCATION FOR A 75 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	1	1	-9	0	2	2	-16	-1
E.N. Centr.	1	1	-6	-1	3	3	-13	-1
Mid. Atl.	8	8	-20	-2	21	22	-32	-6
Sou. Atl.	4	5	-4	-1	9	10	-7	-1
Midwest	3	4	-10	-1	7	8	-18	-2
Southwest	25	27	-11	-1	58	64	-20	-3
Central	0	0	-1	0	1	1	-2	0
N. Centr.	7	7	-9	-1	17	17	-16	-2
West	13	13	-9	-1	31	31	-16	-1
N. West	2	2	-2	0	5	5	-3	0

Source: Authors' calculations

TABLE F-7

PERCENT CHANGE IN ANNUAL SALES DUE TO INDUSTRIAL COST
REALLOCATION FOR A 75 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	0	0	21	2	-1	-1	44	4
E.N. Centr.	0	0	17	3	-1	-1	37	6
Mid. Atl.	-3	-3	64	20	-7	-7	136	41
Sou. Atl.	-2	-2	8	4	-3	-4	16	8
Midwest	-1	-1	25	6	-2	-3	50	12
Southwest	-9	-8	15	9	-18	-16	33	18
Central	0	0	2	1	0	0	4	1
N. Centr.	-2	-3	20	8	-5	-5	42	17
West	-5	-4	24	12	-10	-9	51	25
N. West	-1	-1	3	2	-2	-2	7	3

Source: Authors' calculations

TABLE F-8

PERCENT CHANGE IN RETAIL PRICES DUE TO INDUSTRIAL COST
REALLOCATION FOR A 125 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	2	1	-9	0	2	1	-16	-1
E.N. Centr.	1	1	-6	0	2	2	-12	-1
Mid. Atl.	5	6	-25	0	14	14	-37	-4
Sou. Atl.	3	3	-4	0	6	7	-7	-1
Midwest	3	3	-12	-1	5	6	-21	-2
Southwest	19	20	-10	-1	43	47	-19	-2
Central	0	0	-1	0	1	1	-2	0
N. Centr.	5	5	-9	-1	11	11	-17	-2
West	8	8	-10	-1	19	19	-18	-1
N. West	2	2	-2	0	3	3	-3	0

Source: Authors' calculations

TABLE F-9

PERCENT CHANGE IN ANNUAL SALES DUE TO INDUSTRIAL COST
REALLOCATION FOR A 125 PERCENT REAL CITY-GATE PRICE INCREASE

Utility's Region	50% Reallocation				100% Reallocation			
	Resi- dential	Com- mercial	Indus- trial	Avg.	Resi- dential	Com- mercial	Indus- trial	Avg.
N. Eng.	0	0	22	1	-1	-1	45	3
E.N. Centr.	0	0	16	2	-1	-1	34	4
Mid. Atl.	-2	-2	86	16	-4	-5	178	34
Sou. Atl.	-1	-1	8	3	-2	-2	16	6
Midwest	-1	-1	32	5	-2	-2	63	10
Southwest	-7	-6	14	7	-14	-12	31	16
Central	0	0	2	0	0	0	3	1
N. Centr.	-2	-2	21	7	-3	-4	44	14
West	-3	-3	30	11	-7	-6	60	23
N. West	0	-1	3	1	-1	-1	6	3

Source: Authors' calculations

percent increase in 1985 city-gate prices are presented in tables F-8 and F-9. The results for a 100 percent increase in city-gate prices are set out in chapter 6, tables 6-25 and 6-26.

