

THE FUTURE OF GAS ENERGY

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INTRODUCTION

The purpose of this article is to examine, from the regulated¹ gas² industry perspective, two questions. First, what potential contribution can the gas industry make to future national energy needs? Second, what legal, policy and other barriers must be overcome to make this potential contribution a reality?

Part I of this article deals with the first question. As background, it provides a brief forecast of total United States energy supply and demand through the year 2000. Supply and demand forecasts for gas also are reviewed for the same time frame. While natural gas production from the lower forty eight states is likely to decline slowly over the next 20 years, this decline can be more than offset by gas supplies from supplemental sources. Thus, the gas industry has the potential to continue to provide 25% or more of the nation's total energy supply well into the twenty-first century. Part I concludes with a summary of some attributes of gas to be considered in developing future energy policy.

Part II deals with the second question. This part discusses five barriers the gas industry is likely to face in the future and provides suggestions for overcoming them. The first barrier is the lack of support by the public and certain policymakers. Second, there are specific legal and other barriers to the development of each potential gas supply source such as domestic conventional natural gas and supplemental supplies such as Alaskan gas, Canadian and Mexican imports, liquefied natural gas, coal gasification, synthetic natural gas from liquid hydrocarbons and unconventional gas. The third barrier is the difficulty of raising the additional capital to finance over \$400 billion (in 1980 dollars) of new facilities between now and the year 2000 to produce new gas supplies and provide adequate gas utility service. The fourth barrier consists of marketing restraints on gas sales such as the threat of marginal cost pricing,³ the incremental pricing provisions⁴ of

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¹*I.e.*, gas transmission (pipeline) and distribution companies. For a list of pipelines which have been found to be within the Federal Energy Regulatory Commission's (FERC's) jurisdiction, see FERC News Release (Feb. 13, 1981). There are approximately 1,476 gas distribution companies in the United States. For statistics on distribution companies, including service territories, customers served and income, see *Brown's Directory of North American Gas Companies* 10 (91st ed. 1977). Both gas transmission and distribution companies are regulated industries. On occasion they are called the "gas utility industry." Whether or not they technically or legally are utilities depends upon the particular legal question involved, because the "term [utility] has not been exactly defined." *Wichita Falls v. Kemp Hotel Operating Co.*, Civ. App., 162 S.W. 2d 150, 153, (Tex. Civ. App. 1942), *aff'd.*, 141 Tex. 90, 170 S.W. 2d 217 (1943). Usually, however, distribution companies are utilities for most purposes, while transmission companies, though regulated, generally are not considered utilities because, *inter alia*, they have no exclusive franchise area and no obligation to serve all who desire service.

²For the purposes of this article the words "gas" or "methane" (CH₄, the chief constituent of gas) will be used to describe the product which the gas utility industry sells. As described in part I B of this article, gas or methane can come from many sources such as "natural gas" (found in porous geologic formations beneath the earth's surface), or supplemental sources. For various definitions, see American Gas Association, *Glossary for the Gas Industry* (1975).

³See Part IID 2a *infra* for a discussion of marginal cost pricing.

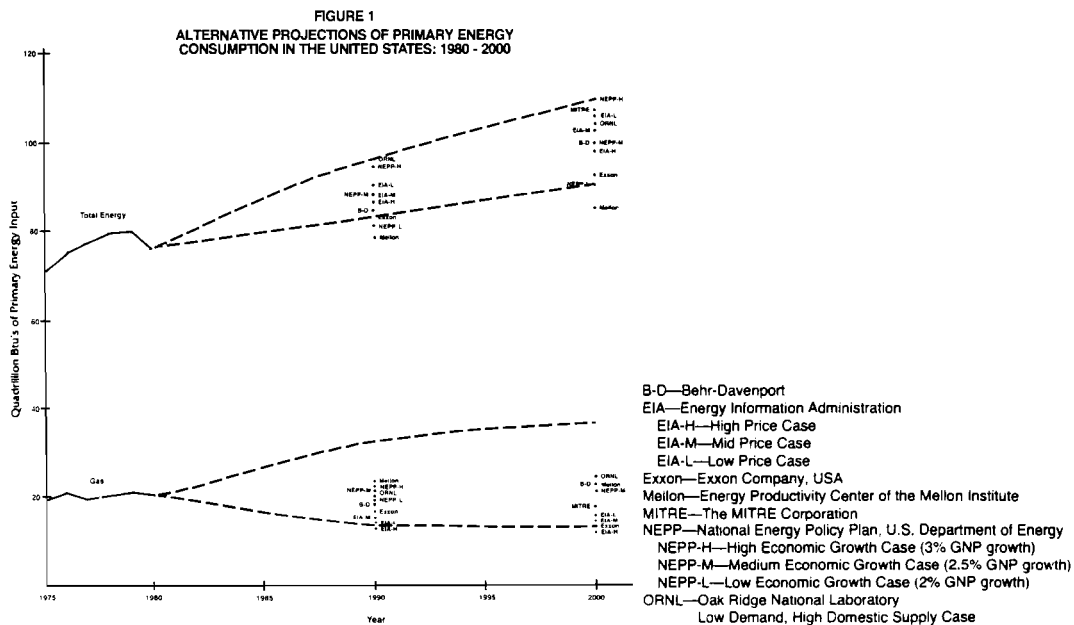
⁴The incremental pricing provisions of the NGPA are set forth in Title II, 15 U.S.C. §§ 3341-3348 (Supp. II 1978). See Section IID 2b *infra* for a discussion of incremental pricing.

the Natural Gas Policy Act of 1978⁵ (NGPA) and certain provisions of the Power-plant and Industrial Fuel Use Act of 1978⁶ (FUA). Problems in the regulatory structure in which gas utilities operate constitute the fifth barrier.

PART I. THE GAS INDUSTRY'S POTENTIAL CONTRIBUTION TO FUTURE ENERGY NEEDS

A. Future United States Energy Supply and Demand

Even assuming continued efforts to conserve energy, future primary energy demand in the United States is projected to reach as high as 90-110 quadrillion Btu's (quads) by the year 2000 as shown in the chart below.⁷



These demand requirements vary depending upon the energy mix and the nation's success in improving efficiencies of energy conversion. In 1980, United States energy consumption was approximately 76 quads.⁸ Thus, an increase of between 18% (14 quads) and 45% (34 quads) more energy must be made available in the next nineteen years to meet anticipated demand.⁹ All sources of energy should

⁵15 U.S.C. §§ 3301-3432 (Supp. II 1978).

⁶42 U.S.C. §§ 8301-8483 (Supp. II 1978). See Section IID 2c *infra* for a discussion of the FUA.

⁷American Gas Association, Energy Analysis, Comparison of Recent Long-Range U.S. Energy Forecasts: 1981 Update (September 18, 1981). Despite differences in various forecasts, generally they are consistent for scenarios assuming a 2.5% to 3% annual growth in Gross National Product (GNP)—widely accepted for estimating purposes as a full employment growth rate. American Gas Association, The Gas Energy Supply Outlook: 1980-2000, at 9 (October 1980) [hereinafter cited as Gas Supply]. See U.S. Dept. of Energy, Securing America's Energy Future, The National Energy Policy Plan, at 31 (July 1981) which forecasts 90-110 quads of energy consumption in the year 2000.

⁸Department of Energy, Monthly Energy Review, 4 (August 1981).

⁹*Id.* Some, however, believe that solar, wind energy and other factors will result in significantly less energy demand. See, e.g., Audubon Rallying Cry: 80 Quads in the Year 2000, 9 The Energy Daily 68, at 2 (Apr. 8, 1981). For an analysis of the Audubon and other energy demand studies, see American Gas Association, Comparison of Recent Long Range Forecasts, 1980-9 (Aug. 23, 1980).

contribute to these needed additional quads, including coal, gas, oil, nuclear, and solar.

The total economic demand for gas energy is forecast to range from 25.2 trillion cubic feet (Tcf) to 27.7 Tcf per year by 1990 in traditional gas markets.¹⁰ Residential consumption of gas should remain fairly stable as new customer growth is offset by conservation.¹¹ However, the demand for gas compared to other fuels in the commercial sector should rise, driven by the increased availability of more efficient gas equipment.¹² Some observers believe that the industrial gas market can double by the year 2000.¹³ Increased gas consumption would result from oil displacement and new industrial growth. Electric power plant demand for gas, however, is expected gradually to decline as gas-fired electric generating plants are retired at a rate of 2% to 3% per year.¹⁴

Gas demand would be higher still—over 30 Tcf by 1990 in traditional markets—if (1) environmental and other restrictions continue to impede coal use;¹⁵ (2) federal policy continues to discourage oil imports; and (3) marketing restraints on gas use such as incremental pricing¹⁶ and certain anti-gas use provisions¹⁷ of FUA are repealed. Further demand for gas energy may develop in non-traditional markets such as expanded gas air-conditioning, the select use of gas in conjunction with coal burning,¹⁸ increased use of gas with high-sulfur residual oil to meet clean air standards,¹⁹ use of gas in strategic energy storage,²⁰ for automotive fleets,²¹ and in gas-fired cogeneration units.²²

¹⁰American Gas Association, *Energy Analysis: A Forecast of the Economic Demand For Gas Energy in the U.S. through 1990*, at 2 (Feb. 9, 1979).

¹¹Address by George H. Lawrence, President, American Gas Association, *Future Developments in the Natural Gas Industry*, The National Oil and Gas Policy Regulation Institute, Washington, D.C. (January 22, 1981) [hereinafter cited as *Lawrence Address*].

¹²*Id.*

¹³*Id.*

¹⁴*Id.*

¹⁵*Id.*

¹⁶*Id.* See Part II D2b *infra* for a discussion of incremental pricing and other marketing restraints.

¹⁷*Id.* See Part II D2a(3) for further discussion of the FUA.

¹⁸*Id.*

¹⁹See EPA Approval and Promulgation of Implementation Plans, Revision, 48 Fed. Reg. 5980 (1981) (to be codified in 40 C.F.R. § 52.2070). This rulemaking provides a variance from EPA's Regulation 8, "Sulphur Content of Fuels," which requires fuel oil burning sources to use fossil fuels containing 0.55 pounds or less, of sulphur per MMBtu of heat released. The revision allows an alternate emission reduction option for control of sulfur dioxide for Narragansett Electric Company, Providence, R.I., to increase its sulphur content from 1% to 2.2% during such times as it burns natural gas at its electric generating station.

²⁰Lawrence Address, *supra* note 11. For a strategic energy storage proposal, see Consolidated Natural Gas Co. and Texas Gas Transmission Corp., *A Proposal for a Contingency Gas Reserve 1* (1980).

²¹*Id.* For a discussion of methane in automobiles, see American Gas Association, *Prospects for Using Natural Gas in Light Transportation Vehicles* (Dec. 1978).

²²*Id.* For a discussion of cogeneration (the burning of certain waste products of an industrial process to generate power; or the recycling of energy in a sequential power generation process to produce power so that both electric energy and useful thermal energy are produced), see Drennan, *Considering the Cogeneration Commitment: Do Government Incentives Tip the Scales?* 1 *Energy L.J.* 2, at 297 (1980).

Dr. Henry Linden, President of the Gas Research Institute (GRI),²³ has observed:

The answer to the question "What really limits gas supply?" may simply be: ignorance! Clearly, the public interest is best served when essential energy services are provided to the customer in a manner which allows him to choose those of greatest utility to him and which allowing for form value, are provided—

- at the lowest total cost;
- from the most abundant domestic sources, supplemented by foreign sources promising the greatest security of supply and the greatest price and monetary stability;
- in the most environmentally benign manner.

*On this basis the demand for gas based on the requisite hierarchy of supplies is likely to be substantially higher than in all government projections.*²⁴

A comprehensive study²⁵ of future gas supply undertaken by the American Gas Association's (A.G.A.'s) Gas Supply Committee indicates that adequate gas supply can be provided to meet anticipated demand. While natural gas production from the lower forty-eight states is likely to decline slowly over the next twenty years, this decline can be more than offset by increasing gas supplies from supplemental sources. Total gas supplies are estimated to range between 23 to 33 Tcf per year by the year 2000 as shown in the following chart.²⁶ Thus, the gas industry has the potential to continue to provide a 25% share of the nation's total energy supply well into the twenty-first century. With proper policies, this supply could increase to the 33% level achieved in the 1960s.

B. Some Advantages of Increased Gas Use

While many energy sources must contribute to future energy needs, increased gas use should be given careful consideration in national energy planning because it has several advantages. First, increased gas use can improve the United States' national security. Approximately 44% of the oil consumed in the United States is imported (in return for which the United States transfers to OPEC countries approximately \$80 billion per year).²⁷ Thus, the United States is vulnerable to

²³The Gas Research Institute is a non profit organization which manages gas research, development and demonstration programs. Such programs are funded by applying a funding unit to specified gas sales and transportation services of members including interstate pipelines, distribution company and municipal utility members. See Opinion and Order Approving the Initial Research, Development and Demonstration Program of Gas Research Institute, FERC Order No. 11, Docket No. RM77-14 (Mar. 22, 1978).

²⁴Address by Dr. Henry R. Linden, President, Gas Research Institute, What Really Limits Gas Supply?, American Gas Association Annual Meeting (Oct. 22, 1979) (emphasis added). See also J. Miller, *Bonanza! America Strikes Gas*, Readers Digest (April 1981) (emphasis added); Gas Research Institute, 1981 Scenario for Future U.S. Energy Demand (1981).

²⁵The results of this 2 year study, undertaken by the Gas Supply Committee of the American Gas Association, were reported in Gas Supply, *supra* note 7. See also American Gas Association, Fact Book: Importance of Gas Energy to Industry (Dec. 16, 1980) [hereinafter cited as Fact Book].

²⁶American Gas Association, Gas Facts 1979, 66-67 (1980) [hereinafter cited as Gas Facts 1979]; see also Gas Supply, *supra* note 7. See also Bert and Davenport, API/AGA Pipeline Report 79 Oil and Gas Journal 79 (June 15, 1981); The Mitre Corp., U.S. Energy Strategies: Some Options for Eliminating Oil Imports by the Year 2000, at 12 (April, 1981); and Gas: *What's Underground?* The Energy Daily, May 26, 1981, at 4.

²⁷American Gas Association, Energy Analysis: Potential of Increased Gas Supply Capability to Reduce Impacts to the U.S. Economy of a Major Oil Supply Disruption, 1980-8, at 1 (June 27, 1980).

POTENTIAL GAS SUPPLIES

(TCF)	Year 2000				
	Actual 1979	Self Sufficiency Scenario ¹	North American Focus Scenario ²	Moderate World Imports Scenario ³	World Conventional Gas Emphasis Scenario ⁴
Conventional Lower-48	19.9	12-14	12-14	12-14	12-14
SNG	0.2	0.3	0.3	0.3	0.1
Alaskan Gas	—	3.0	3.0	1.5	3.0
Canadian	1.0	1.0	2.0	2.0	2.0
Mexican	—	0.1	2.0	2.0	2.0
LNG	0.2	0.7	0.7	2.5	4.0
Coal Gas	—	3.5	3.5	1.5-2.5	1.5-2.5
Tight Formations	—	1.5-5.0	1.5-4.0	1.5-3.0	1.5-3.0
<u>Nonconventional Sources</u>	—	1.0-2.5	1.0-2.5	1.0-2.5	1.0-2.5
Total Supply	21.3	23.1-31.0	26.0-32.0	24.3-30.3	27.1-33.1

¹ Assumes a strong national policy of minimizing energy imports.

² Assumes a national energy policy which emphasizes development of North American sources of gas and other fuels.

³ Assumes a national energy policy of maintaining a broad mix of fuels from diverse sources.

⁴ Assumes emphasis on development of world conventional gas resources and the transmission of that gas to wherever it is needed.

Source: *The Gas Energy Supply Outlook: 1980-2000* (Arlington, VA, American Gas Association, October 1980).

economic and other pressures from major oil exporting countries.²⁸ In the event of a major supply disruption in the Persian Gulf, the United States not only would lose this supply but also could be required under the International Energy Agency (IEA)²⁹ oil shortage sharing agreement³⁰ to share part of its remaining oil supply with other importing nations.³¹

Replacing a substantial portion of these oil imports with a secure domestic energy source should be a matter of high national priority. Gas is an appropriate substitute for imported oil. It could contribute to reducing dependence on OPEC oil by supplying most stationary residential, commercial and industrial markets that currently use oil. It is a secure, domestic resource—95% of the gas consumed in the United States is domestically produced.³²

Second, gas has certain financial and economic advantages over other energy sources. On a Btu basis, the capital investment costs for new gas are forecast to be lower than for most other new domestic energy supplies.

²⁸ The U.S. depends directly on the Persian Gulf Region for 25% (2.0 million bbls./day) of its total petroleum imports and indirectly (through imports of products refined in the Caribbean from the Persian Gulf oil) for an estimated additional 6% (.5 MMbbls./day of such imports). Energy Analysis, *supra* note 27. See also address by David J. Muchow, General Counsel, Corporate Secretary, American Gas Association, Third Annual Regulatory Conference, Washington, D.C. (October 1980).

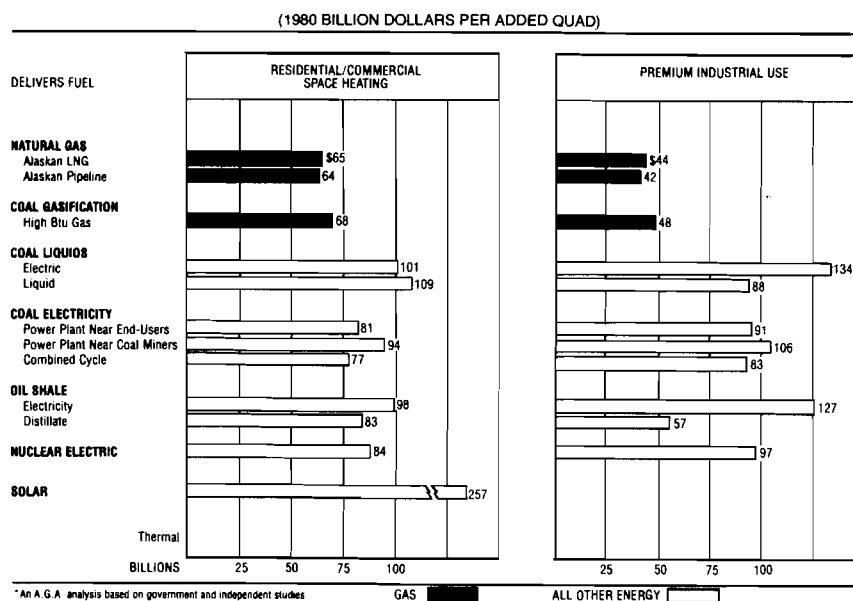
²⁹ For details on the International Energy Agency see the International Energy Agreement of 1974, 25 U.S.T. 223, T.S.I.A. No. 7791, at Chapter IX (Nov. 18, 1974). The International Energy Agreement provides for a prearranged system of energy allocation in the event of an oil shortfall by any IEA member. If such a shortfall should occur each party to the treaty will decrease its oil demand through demand restraints by 7% and any remaining shortfall will be shared by all parties at pre-import demand levels.

³⁰ *Id.*

³¹ *Id.*

³² Fact Book, *supra* note 25.

AVERAGE CAPITAL INVESTMENT ESTIMATES FOR NEW DOMESTIC ENERGY



As the above chart³³ shows, domestic energy supply and utilization systems based on gas (natural or synthetic) require from 36 to 65% less new capital investment than the equivalent nuclear, coal and solar electric systems or synthetic liquids-based systems. All steps from source to use (extraction, processing, transportation, and end-use equipment) are included in this analysis. On a national average basis, supplying added quantities of gas energy from domestic resources for direct use in residential and commercial space heating will require from 18 to 40% less capital than electrification to produce the same amount of useful energy.³⁴ Supplementing priority industrial requirements with domestic gaseous and liquid fuels requires about one-third less capital than developing new electric power for this market.³⁵

In residential and commercial markets, gas costs less per Btu delivered to the point of use on a nationwide average basis than oil or electricity. In 1980, for instance, residential users paid \$3.52 for gas, \$7.64 for oil and \$15.71 for electricity per MMBtu's.³⁶ This gas cost advantage is expected to narrow in the future. However, even assuming gas is deregulated pursuant to the NGPA, it is estimated that by 1990 gas for the residential market still will cost 37% less than oil and about 66% less than electricity.³⁷

³³Gas Supply, *supra* note 7, at 49.

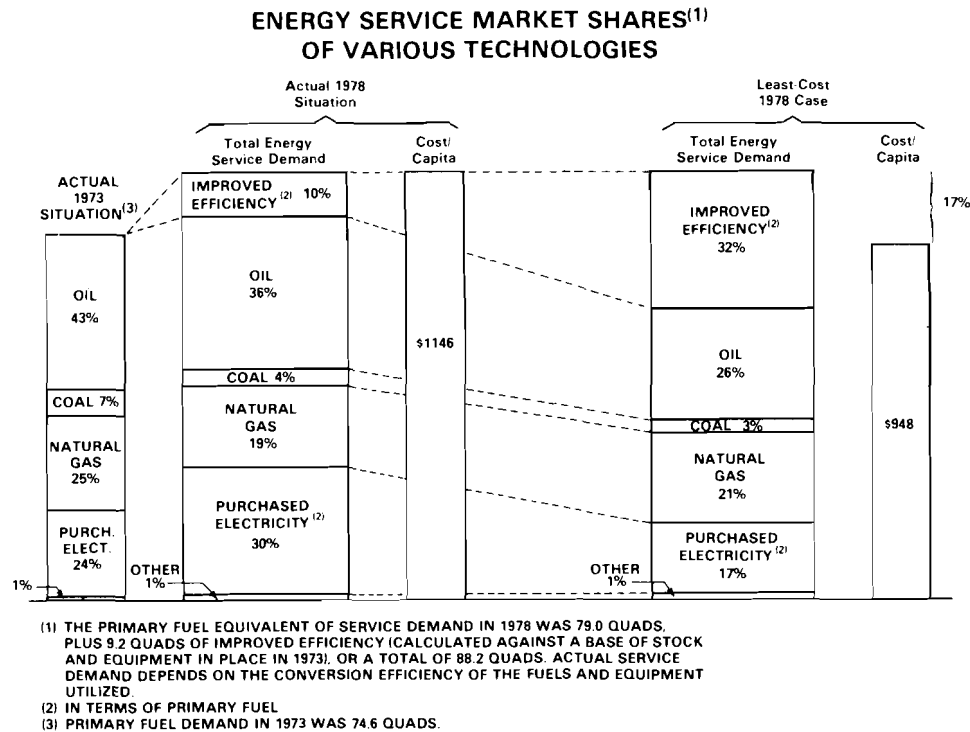
³⁴American Gas Association, Fact Book: Synthetic Pipeline Gas From Coal, Part E, (Oct. 1979).

³⁵*Id.*

³⁶Department of Energy, Monthly Energy Review 77, 89, (May 1981); American Gas Association, Quarterly Report of Gas Industry Operations, 4th. Quarter (1980).

³⁷American Gas Association, Energy Analysis: Consumer Cost of Natural Gas and Alternative House Heating Fuels 19 (Nov. 21, 1980).

The third advantage involves the role of gas in the "least-cost energy strategy." In 1979, the Energy Productivity Center of the Mellon Institute conducted a study concerning the "least-cost energy strategy"³⁸ i.e., a strategy which concentrated on the most economical way of obtaining essential services (heat, light and mechanical motion). This study compared the actual United States energy use patterns in 1978 with a hypothetical case representing what the energy use patterns would have been if energy supply and end-use equipment were reconfigured to minimize consumer cost.

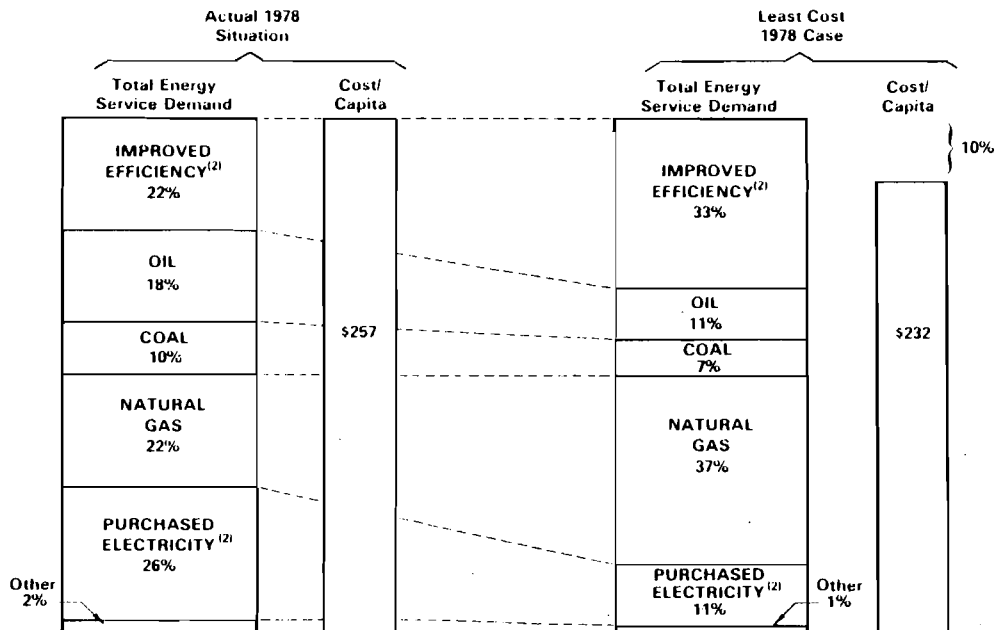


As the above chart³⁹ shows, if the United States had been following a least-cost strategy for the last 10 to 15 years, consumer costs for energy services in 1978 would have been about 17% less than actually experienced. Annual per capital energy costs would have been reduced from \$1,146 to \$948, with accompanying benefits to the nation's security (from less imported oil) and the environment. Furthermore, (1) gas use overall would have to be 10% greater, but 27% less oil and 43% less electricity would have been used; (2) industrial gas use would have been 68% greater (its market share would have increased from 22% to 37%) while far less use of oil (39% less), coal (30% less) and purchased electricity (58% less) would have occurred (this conclusion was developed before oil prices increased in 1980-81);

³⁸The Energy Productivity Center, Mellon Institute, The Least Cost Energy Strategy (1979).

³⁹*Id.* at 29.

INDUSTRY ENERGY SERVICE MARKET SHARES⁽¹⁾ OF VARIOUS TECHNOLOGIES



(1) THE PRIMARY FUEL EQUIVALENT OF SERVICE DEMAND WAS 28.2 QUADS, PLUS 7.9 QUADS OF IMPROVED EFFICIENCY AND 0.8 QUADS OF BIOMASS (CALCULATED AGAINST A 1973 BASE), OR A TOTAL OF 36.9 QUADS.

(2) IN TERMS OF PRIMARY FUEL

and (3) the use of all fuels in buildings (spaceheating, etc.) would have been 25 to 38% less if more efficient technologies had been in use.⁴⁰ As depicted in the chart *infra* this study suggests that gas saved through enhanced residential efficiency should be redirected toward the industrial sector where increased gas use could displace oil and electricity.⁴¹

A fourth advantage of gas is the already existing 1 million mile pipeline and distribution system which runs continuously from the point of production to the point of use. This pipeline/distribution system is a part of the most efficient major energy delivery system in the United States.⁴²

⁴⁰*Id.* at 30.

⁴¹*Id.* at 32. For discussion of the costs of the Least Cost Energy Strategy, see *Least Cost Energy Strategy Carries A Hefty Price Tag*, 9 *The Energy Daily* 1 (March 5, 1981).

⁴²Fact Book, *supra* note 25.

A fifth advantage of gas is its "system efficiency". Total comparative system efficiencies for major fuels are as follows:

- Gas is over twice as efficient as electricity in providing residential space heating with conventional end-use equipment, and is estimated to be from 25% to 100% more efficient using advanced end-use equipment such as electric heat pumps and high efficiency gas furnaces.⁴³
- Gas and oil have approximately the same total system efficiencies when used for residential space heating, assuming conventional end-use equipment. When advanced gas equipment is used, gas heating is expected to be between 33% and 50% more efficient than oil heating.⁴⁴
- Coal gasification is between 29% and 56% more efficient than coal electrification when used for residential space heating (depending upon the type of advanced end-use equipment assumed). Total system efficiency for a coal gasification energy cycle is approximately 53%. A comparable coal electric cycle is estimated to be approximately 43% efficient.⁴⁵

Another advantage of gas over coal or electricity is that vast amounts (6.1 Tcf) are stored in 400 underground storage fields near large markets to meet seasonal demands. Such gas can be transported from storage quickly when needed.⁴⁶

As the following chart⁴⁷ indicates, gas is the cleanest of all fossil fuels. Proper gas combustion yields, almost exclusively, two naturally occurring by-products, carbon dioxide and water vapor.

POUNDS OF EMISSION PER 10⁹ BTU COMBUSTED

Air Pollutants	Gas	Oil	Coal	Select Use*
Sulfur Oxides	0.6	160-1,080	450-3,020	280-1,870
Particulates	5-15	140-720	60-9,440	40-5,860
Carbon Monoxide	17-20	40	44-88	34-62
Hydrocarbons	1-8	7	13-44	8-30
Nitrogen Oxides	80-700	130-760	670-2,440	450-1,780

*Mixture of 62 percent coal and 38 percent gas by BTU content in this example

Note: The lower end of the range for coal and oil emissions represents best available control technology and therefore is well below average emissions from most existing sources.

Sources: Environmental Protection Agency
U.S. Department of Energy
Hittman Associates, Inc.
American Gas Association

⁴³*Id.*

⁴⁴*Id.*

⁴⁵*Id.*

⁴⁶Over half of this (3.5 Tcf) is "cushion" gas required for field pressure maintenance. Of the remainder, 2.8 Tcf of "working" gas, is available for winter peak requirements. American Gas Association, Gas Facts, 45 (1978). Some gas transmission and distribution companies have proposed increasing storage to meet expanding heating load requirements, reduce industrial customer vulnerability to gas service interruptions and to meet strategic needs. American Gas Association Monthly 1, 2 (1980). Additional storage is necessary particularly in areas such as New England which have high winter peak demands.

⁴⁷Fact Book, *supra* note 25, at 17.

Because of its low level of pollutants, a select use of gas can allow more oil or coal to be burned in compliance with the Clean Air Act.⁴⁸ Because of its "cleanliness", gas can be used in critical process uses, such as food processing or in bakeries where oil or coal could not be used directly.⁴⁹ Finally, because gas equipment (such as furnaces and boilers) generally produces less pollution, it usually requires less maintenance than oil or coal fired equipment.⁵⁰

Gas can make a significant contribution to the nation's future energy needs. Because of its inherent advantages, national policies should be charted which permit gas to fulfill a significant role.

PART II. MAJOR BARRIERS TO REALIZING THE POTENTIAL GAS CONTRIBUTION

There are five obstacles which must be overcome for gas to achieve its potential future contribution—attitudinal, supply, financial, marketing and regulatory.

A. *The Attitudinal Barrier*

One problem the gas industry faces in the future is attitudinal—insufficient public appreciation of and support for having gas achieve its potential contribution.⁵¹ The gas utility industry is regulated at Federal, state and sometimes local governmental levels from the well-head⁵² to the burner tip.⁵³ Thus, it faces critically important governmental policy control on all sides. For instance, in its first message to Congress on energy in 1977,⁵⁴ the Carter Administration believed that there was little hope for continued gas supplies beyond the year 2000. Thus, it de-emphasized gas and focused on developing nuclear energy and coal. Under this approach, tax penalties were proposed as a disincentive for the use of gas and petroleum in industrial and powerplant applications. Wellhead prices for gas sold interstate would have received only marginal increases, while intrastate market prices would have been reduced.⁵⁵ However, because of Congressional reaction to the original Carter Administration proposals, the Administration gradually shifted to a position supporting phased deregulation of new natural gas. Thereafter, Congress provided price incentives to encourage gas production in the NGPA as part of the National Energy Act of 1978.⁵⁶ These price incentives have

⁴⁸*Id.* The Clean Air Act is found at 42 U.S.C. §§ 7401-7642 (1976).

⁴⁹E. Oppenheimer, *Natural Gas: The New Energy Leader* 76 (1980). [hereinafter cited as *Natural Gas*]. As to cleanliness, proper gas combustion yields primarily two products found naturally in the environment, carbon dioxide and water vapor.

⁵⁰*Id.*

⁵¹For example, see discussion in Part IB *infra* regarding the ratio of federal research and development expenditures for electricity vs. gas.

⁵²In *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954), the Supreme Court held that the Federal Power Commission had jurisdiction under the Natural Gas Act, 15 U.S.C. § 717-717w (1976), over the rates charged by producers for gas sold in interstate commerce for resale.

⁵³See discussion in Part IID2 *infra*.

⁵⁴President's Message to Congress, Transmitting a Draft of Proposed Legislation to Establish a Comprehensive National Energy Policy (April 29, 1977).

⁵⁵*Id.* at 6, 7, 69.

⁵⁶These incentives are discussed at Part IIB1 *infra*. The National Energy Act is not a separate public law; rather it consists of 5 laws: Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3301-3342 (Supp. II 1978), National Energy Conservation Policy Act, 42 U.S.C. §§ 8201-8278 (Supp. II 1978), Powerplant and Industrial Fuel Use Act of 1978, 42 U.S.C. §§ 8301-8483 (Supp. II 1978), Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-2645 (Supp. II 1978), and the Energy Tax Act of 1978 (codified in various sections of 26 U.S.C.).

led to record gas exploration and production efforts. This mistaken belief that the Nation rapidly is exhausting its gas resources has been a constant attitudinal barrier to the development and marketing of gas supplies.⁵⁷

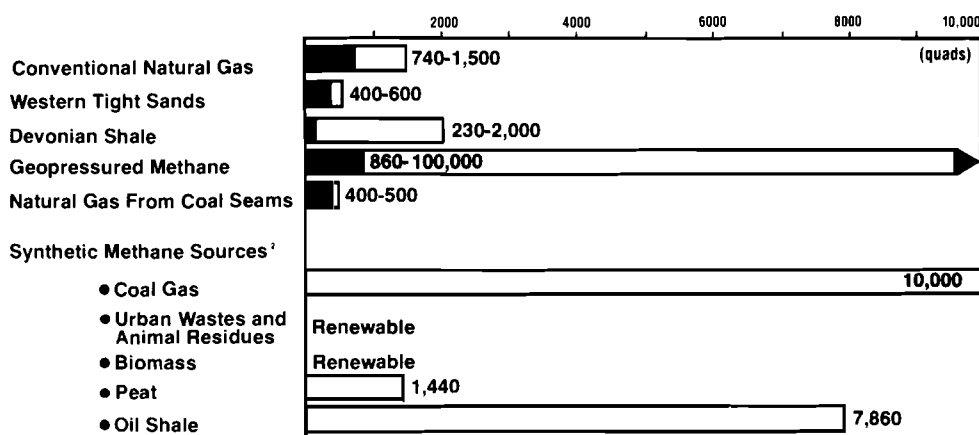
Second, unlike the electric industry, the gas industry generally is not vertically integrated. Rather, it is composed of three distinct segments: production, transmission and distribution. Thus, it frequently is not homogenous in its approach to public policy issues. This results in some confusion about the industry and its goals and makes it more difficult to achieve them.

Finally, the attitudinal barrier manifests itself in changing emphasis and direction in energy policy based upon temporary situations. The nation's energy policies must be developed and followed with a long range view of objectives and means. Long lead times and vast financial commitments are required for major gas energy projects.

B. Gas Supply Sources

Gas or methane energy potentially is available from many sources. The development of each source faces different problems. A summary of each major source, its resource base (shown in the following chart)⁵⁸ and significant barriers (*e.g.*, policy, legal, and technological) to its development follows:

Total Potential Energy Resource In-Place¹



Note. Estimates as of 1-1-80. For purposes of scale, total U.S. energy consumption in 1979 was 78 quadrillion Btu's (quads).

¹Recovery and conversion factors range from as high as 85 percent for conventional gas wells (with a national average of approximately 80 percent) to around 10 percent for some of the unconventional sources.

²Estimates assume 100 percent of the potential resource utilized to produce methane.

Sources: American Gas Association
Gas Research Institute
U.S. Geological Survey

⁵⁷For a discussion of gas exploration and production developments see American Gas Association, A.G.A. News (May 5, 1980).

⁵⁸Fact Book, *supra* note 25, at 11.

1. Domestic Conventional Gas

Estimates of conventional United States natural gas resources (including Alaskan reserves) range from 700 to 1200 Tcf.⁵⁹ Thus, at the current U.S. consumption rate of about 20 Tcf/year, there are between 35 and 60 years of conventional gas supply remaining to be produced.

As a depleting resource, the exploration and development of new conventional gas generally involves higher costs than those incurred to find and produce existing supplies. This problem of higher costs has been exacerbated by the recent impact of inflation.

Title I⁶⁰ of the NGPA provided necessary new pricing incentives to new conventional gas supplies:

- It mandated phased deregulation of "new" natural gas from 1977 through 1985. An initial ceiling price of \$1.75/million Btu's was set for April 20, 1977. That maximum price was to escalate monthly at an annual rate of 3.5% until April 20, 1981 and thereafter at 4%, in addition to inflation.⁶¹ Other categories of gas were accorded escalating maximum ceiling and other price provisions which varied with each category.
- Section 107(c)⁶² of Title I provided further incentives to "high cost" gas such as new gas below 15,000 feet, geopressured gas, occluded gas from coal seams, gas from Devonian shale and "gas produced under such other conditions as the Commission determines to present extraordinary risks or costs."⁶³ The first four categories were deregulated in 1979, while the fifth was allowed special incentive prices to be determined by FERC.⁶⁴

These NGPA price incentives have had a beneficial impact on new gas exploration and development. From 1979 to 1980 seismic activity reached record levels with a 32% increase, while additions to proved reserves in 1979 were 14.3% Tcf, an increase of 35% over 1978.⁶⁵ These numbers signaled a slowdown in the rate of decline of United States natural gas reserves. Gas production from 1978 to 1979 increased 3.1% from 19.3% Tcf to 19.9% Tcf.⁶⁶ Currently, it appears that Title I phased deregulation is working.

Title I was designed to bring gas prices into parity with oil prices, estimated to be \$15/bbl. in 1985. With the decontrol of domestic oil and the OPEC oil price increases coming much faster than expected,⁶⁷ some have suggested that the NGPA price incentives may need revision so that in 1985 when much of the gas is

⁵⁹Gas Supply, *supra* note 7, at 6.

⁶⁰15 U.S.C. §§ 3301-3333 (Supp. II 1978).

⁶¹Section 102(b), 15 U.S.C. § 3312 (Supp. II 1978).

⁶²Section 107(c), 15 U.S.C. § 3317(c) (Supp. II 1978).

⁶³*Id.*

⁶⁴*Id.* This part specifies the maximum lawful price for natural gas which is defined therein as new natural gas and certain natural gas produced from the outer continental shelf, gas from new onshore production, natural gas committed or dedicated to interstate commerce, sales under existing intrastate contracts, high cost natural gas, stripper well gas or other categories of natural gas, 18 C.F.R. 271 (1980).

⁶⁵A.G.A. News, *supra* note 57.

⁶⁶*Id.*

⁶⁷Domestic oil prices were decontrolled by President Reagan on January 28, 1981 by Executive Order No. 12287 issued pursuant to the Emergency Petroleum Allocation Act of 1973, 15 U.S.C. § 751 (1980).

deregulated, the price spread between new gas and oil will not cause a "price spike."⁶⁸

Some policy makers have suggested that all gas immediately be decontrolled to encourage further production.⁶⁹ One basis for this is that the price of oil has increased more than anticipated and the NGPA ceiling prices are falling behind, thus making gas exploration and development relatively less attractive than oil. It appears, however, that immediate decontrol may have an unacceptable effect on inflation. One estimate shows that deregulating all gas (both currently flowing gas and new discoveries) in the Fall of 1981 would double gas prices for all customers, increase inflation by 3.4% in the first full year of decontrol and result in 10% less gas being used in the United States. This would increase oil imports nearly one million bbls/day resulting in an additional \$12 billion in foreign oil import payments.⁷⁰

Even with existing NGPA price incentives, however, conventional natural gas supplies in the lower 48 states are projected to decline from annual current levels of 19 Tcf to about 14 Tcf by the year 2000. If total gas supplies required by the year 2000 range from 23 to 33 Tcf/year,⁷¹ then, supplemental and unconventional gas supplies of from 9 to 19 Tcf/year must be developed in just 19 years.

2. Alaskan Gas

Alaskan gas is the single largest concentration of United States' gas resources, with proved reserves of 31.9 Tcf and potential reserves of well over 100 Tcf, approximately 10% of the United States estimated conventional resource base.⁷² A pipeline transportation system is needed to bring these Alaskan reserves to lower 48 state markets.⁷³ An Alaskan gas pipeline also will help Canadians develop their northern gas resources, some of which can be exported to this country. Such a pipeline is a most costly project (over \$30 billion), yielding expensive gas (\$8-9 per Mcf if deliveries begin in 1985).⁷⁴ Thus, the major problem in developing Alaskan gas supplies is a financial one.

Basic to the financing problem are the price of the gas and meaningful participation by the Alaskan producers in an equity or other position in the project. The price issue has become intertwined with several questions including responsibility for the costs of constructing, processing and conditioning facilities.⁷⁵

⁶⁸See discussion in *The Wall St. J.*, Mar. 17, 1981, at 1, col. 1; Berry, *Reagan Will Try to Hasten Decontrol of Natural Gas*, *The Wash. Post*, Mar. 7, 1981, at 3, col. 1; *McClure Says Oil Price Hike Rules Out Chances of 1981 Gas Decontrol*, *Inside FERC* 1, Mar. 16, 1981. price spike concern has been expressed over indefinite price escalation clauses in gas contracts, see American Gas Association, *Analysis of natural Gas producer Interstate Pipeline Contracts*, 9 *Gas Energy Review*, 9, at 5 (Sept. 1981).

⁶⁹*Id.*

⁷⁰American Gas Association, *Cost of Immediate Total Wellhead Price Decontrol of Natural Gas to Low Income and Disadvantaged Groups 1981-5* (April 9, 1981).

⁷¹See Part 1A, *supra*; see also *Gas Supply*, *supra* note 7, at 3.

⁷²*Supra* note 7, at 14, 15.

⁷³*Gas Supply*, *supra* note 7, at 21.

⁷⁴American Gas Association, *Energy Analysis: A Forecast of Capital Requirements of the U.S. Gas Utility Industry to the Year 2000: 1980 Update* 4, 5 (Oct. 17, 1980). Some suggest that the delivered price may be as high as "a delivered price at the Chicago city gate of \$15/Mcf." *The Wall St. J.*, Mar. 16, 1981, at 4, col. 1.

⁷⁵As to price, § 109(a)(4)(b) of the NGPA, 15 U.S.C. § 3319(a)(4)(b) (Supp. II 1978), established a statutory ceiling price for Prodhue Bay gas at \$1.45/MMBtu as of April 1977, adjusted for inflation thereafter. Section 110 (a)(2) of the NGPA, 15 U.S.C. § 3320(a)(2) (Supp. II 1978), permits (to the extent allowed by the FERC) that the § 109(a)(4), 15 U.S.C. § 3319(a)(4) (Supp. II 1978), ceiling price shall not be considered to be exceeded to the extent necessary to recover costs of compressing, gathering, processing, treating, liquefying or transporting such natural gas or other

The ownership of the proposed Alaskan Natural Gas Transportation System (ANGTS) has been a subject of considerable controversy. In 1977, a report of the Department of Justice recommended that an ownership interest, or participation in any form in the Alaskan Pipeline System by producers and their subsidiaries or affiliates, should be prohibited.⁷⁶ Subsequently, the Department of Justice stated that its opposition was limited to any financial participation by producers which would enable them to engage in anti-competitive conduct, such as the restriction of pipeline throughput, the denial of access to non-owners, or the resistance to or denial of future expansion of pipeline capacity. This recommendation assumed that in certain circumstances, producers would have incentives to prevent expansion of the ANGTS or to restrict access to it.⁷⁷

The Department of Justice's recommendation was adopted in the *President's Decision*,⁷⁸ which was subsequently approved by a joint resolution of Congress.⁷⁹ The *President's Decision* provided that Alaskan producers must be excluded from ownership of the ANGTS, except that they may provide guarantees for project debt. Further, such producers may not be equity members of the sponsoring consortium, have voting power in the project, have a role in the management or operation of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put into effect, or impose conditions on the guarantees of project debt which may give rise to competitive abuse.⁸⁰

With the costs of the project continually increasing, it appears that private financing of at least the Alaskan segment of the project may not be feasible without further participation by the Alaskan producers. Efforts are continuing to structure a meaningful participation by the producers within the parameters of the *President's Decision*. A step was taken in this direction when in June, 1980, the Alaskan producers and the pipeline sponsors of the Alaskan segment of the project agreed jointly to fund and manage the remaining design and engineering activities of the project and jointly to develop a financing plan. The Department of Justice has approved this arrangement.⁸¹ In February, 1981, the United States and Canadian governments exchanged letters on the occasion of the ceremony

similar costs incurred by the seller. Thus, determining the maximum lawful price for the Prodhue Bay gas requires the FERC to determine which allowances should be allowed under § 110. See, e.g., Treatment of Certain Production-Related Costs For Natural Gas to be Sold and Transported Through the Alaska Natural Gas Transportation System, FERC Order 45, Docket No. RM79-19, Aug. 24, 1979, on conditioning gas. While producers are responsible for conditioning, their allowance for doing so is limited to removing carbon dioxide to levels below 3% by volume, Order 45, at 2; see also Order Granting Rehearing for the Purpose of Further Consideration and Further Staying of Order No. 45 and Order No. 31-A, Docket No. RM79-19, Nov. 30, 1979. For a discussion of this, see T. Bindra, chapter on *Canadian, Mexican and Alaskan Supplies*, from Regulation of the Gas Industry (1981). See also Report of the Committee on Natural Gas Imports and Exports (Federal Energy Bar Association), 1 Energy L. J. 165-174 (1980).

⁷⁶Report of the Attorney General, I. Impact on Competition: Summary of Recommendations of the Federal Power Commission and the Department of Justice, United States Department of Justice, filed pursuant to Section 19 of the Alaskan Natural Gas Transportation Act (ANGTA), 15 U.S.C. § 719 *et seq.* (1976), (July 1977).

⁷⁷Letter from Hugh P. Morrison, Jr., Acting Assistant Attorney General, to Leslie J. Goldman, Assistant Administrator, Energy Resources Development, (Aug. 9, 1977).

⁷⁸Decision and Report to Congress on the Alaskan Natural Gas Transportation System, Executive Office of the President (Sept. 1977).

⁷⁹H. R. J. Res. 621, 95th Cong., 1st Sess., P.L. 95-158, 91 Stat. 1268 (1977).

⁸⁰Decision and Report, *supra* note 78.

⁸¹Letter from John H. Shenefield, Assistant Attorney General, to Charles W. Duncan, Secretary, Department of Energy, (June 18, 1980).

marking initial construction in the United States of the Western leg of the ANGTS. In that exchange the United States repeated that it "is firmly committed to the completion of ANGTS" and stated, "We expect the United States sponsors and producers will soon reach an agreement on a tentative financing plan."⁸²

3. Imports of Natural Gas

Until recent years natural gas import volumes were relatively minor.⁸³ However, as imports increase (currently they are 1.2 Tcf out of a total of 21.3 Tcf of total gas production)⁸⁴ the governmental role, as implemented by the Economic Regulatory Administration (ERA) and the FERC, becomes more important.

The authority over regulation of imports (and exports) of natural gas is contained in Section 3⁸⁵ of the Natural Gas Act (NGA).⁸⁶ Section 3 provides that natural gas may be imported into the United States unless such importation "will not be consistent with the public interest." Under the Department of Energy Organization Act (DOE Act),⁸⁷ Section 3 authority is vested in the Secretary of Energy. The Secretary has, in turn, delegated this authority to both FERC and ERA. The nature and scope of their authority depends upon the issues to be decided.⁸⁸

ERA is responsible for deciding whether the proposed import is consistent with the public interest.⁸⁹ This judgment is based upon various factors including security of supply, balance of payments, price of the import or export, and national and regional needs for gas. ERA also may impose conditions on the import price, escalation clauses or any other import terms.⁹⁰

FERC is responsible for import functions under Section 3 of the NGA which have not been delegated to ERA, which ERA chooses not to exercise, or which are reserved to FERC.⁹¹ FERC considers the site, construction and operation of particular facilities, and the place of entry of an import (Section 7⁹² of the NGA); the rates and charges for jurisdictional gas sales (Section 4⁹³ of the NGA); and whether such rates are "unjust, unreasonable, unduly discriminatory or preferential" (Sec-

⁸²Letter from James B. Edwards to H. A. Olsan (Feb. 6, 1981); letter from Peter M. Towe to James B. Edwards (Feb. 18, 1981); released in DOE News (Feb. 19, 1981). See *Hallelujah! Deal Struck on Alaska Pipeline*, 10 *The Energy Daily*, May 26, 1981, at 2, col. 1.

⁸³For example, in 1962, net imports were still less than .5 Tcf. By 1963, they had almost doubled. Gas Facts 1979, *supra* note 26, at 45.

⁸⁴Gas Facts 1979, *supra* note 26, at 31.

⁸⁵15 U.S.C. § 717b (1976).

⁸⁶15 U.S.C. § 717a-w (1976).

⁸⁷42 U.S.C. §§ 7101-7352 (1976).

⁸⁸*Id.* see DOE Delegation Order No. 0204-4 (Oct. 1, 1977), 42 Fed. Reg. 60726 (Nov. 29, 1977); DOE Delegation Order No. 0204-54, 44 Fed. Reg. 56735 (Oct. 2, 1979); DOE Delegation Order No. 0204-55, 44 Fed. Reg. 56735 (Oct. 2, 1979). See also Report of the Committee, *supra* note 75; Grenier and Clark, *The Relationship Between DOE and FERC: Innovative Government or Inevitable Headache?* 1 *Energy L. J.* 325, 346-352 (1980); Order Granting Applications, Pacific Alaska LNG Co., FERC Docket Nos. CP 75-140, at 6-11; Order on Rehearing Modifying and Clarifying Order Granting Applications, Pacific Alaska LNG Co., FERC Docket Nos. CP75-140, at 2-4, (Dec. 12, 1979); Findings and Order, Border Gas, Inc. Docket No. CP80-93, (Dec. 21, 1979); Order Authorizing the Importation of Natural Gas, Northern Natural Gas Co., a Division of InterNorth, Inc., Docket No. CP80-22, at 4-6 (June 27, 1980); Order Authorizing the Importation and Exportation of Natural Gas, The Brooklyn Union Gas Co., FERC Docket No. CP81-105-000, at 2,3 (Dec. 19, 1980).

⁸⁹Delegation Order No. 0204-54, *supra* note 88.

⁹⁰*Id.*

⁹¹Delegation Order No. 0204-55, *supra* note 88.

⁹²15 U.S.C. § 717f(b) (1976).

⁹³15 U.S.C. § 717c (1976).

tion 5⁹⁴ of the NGA). If FERC authorizes an import, it must include in its order any terms or conditions previously attached by the ERA.⁹⁵ Originally, the FPC had jurisdiction over both Section 3 and Section 7 authority. Even then, there was controversy over the interrelationship of these sections.⁹⁶

In *Distrigas Corp.*, a U.S. Court of Appeals held that the FPC's Section 3 authority was "at once plenary and elastic."⁹⁷ Further, the court reasoned that the FPC may authorize imports of LNG under Section 3 and impose on them the "equivalent of Section 7 certification requirements" even when (1) certification itself could not be required because interstate commerce was not involved; and (2) the Commission had previously disclaimed jurisdiction over the same facilities.⁹⁸

With the jurisdictional split between ERA and FERC it is even more likely that some of the issues tried in a Section 3 proceeding will be tried again in a Section 7 proceeding and thus delay import projects. Legal authority exists to cure this problem. Section 402(e)⁹⁹ of the DOE Act allows the Secretary of Energy to delegate its Section 3 authority to the FERC. The Secretary currently is studying this problem to see if such delegation would be appropriate.¹⁰⁰

(a) Canadian Imports

Currently, the United States imports about 1 Tcf of gas per year from Canada. This volume could increase to 2 Tcf by the year 2000.¹⁰¹ The Canadian National Energy Board estimates that ultimate marketable gas resources in conventional producing areas at year end 1978 range from 127 to 157 Tcf, not including Canadian Geological Survey estimates of frontier potential gas of up to 300 Tcf.¹⁰²

However, there are recurring problems with gas imports from Canada. Canadian gas exports help to offset the cost of Canada's oil imports. Thus, Canada seeks gas export prices at parity with world oil. At such prices, however, it appears that Canadian gas supply may exceed the United States' demand for it.¹⁰³ The ERA has had reservations about approving prices based on parity with Canadian imported oil prices.¹⁰⁴ The ERA also has suggested that the question of over-reliance on Canadian gas should be explored.¹⁰⁵ The FERC has questioned the take or pay terms of certain contracts in view of the increasing costs of gas and has required that take or pay terms be keyed to a dollar amount and not volume.¹⁰⁶ In one case, the California Public Utilities Commission denied a California gas utility its purchased gas costs for Canadian gas on the grounds that it was impru-

⁹⁴15 U.S.C. § 717d (1976).

⁹⁵Delegation Order No. 0204-55, *supra* note 88.

⁹⁶*Distrigas Corp. v FPC*, 495 F.2d 1057 (D.C. Cir.); *cert. denied*, 419 U.S. 834 (1974).

⁹⁷*Id.* at 1064.

⁹⁸*Id.* at 1059.

⁹⁹15 U.S.C. 717(f) (1976).

¹⁰⁰Address by R. Tenney Johnson, General Counsel Designate, DOE to Federal Energy Bar Association Annual Meeting, Wash., D.C. (May 14, 1981).

¹⁰¹Gas Supply, *supra* note 7, at 17; *see also Canada's National Energy Program: An Update*, IGT Energy Topics (Chic., Ill.) (Mar. 30, 1981).

¹⁰²Gas Supply, *supra* note 7, at 17.

¹⁰³*Id.*

¹⁰⁴Opinion and Order Authorizing Payment of an Increased Border Price for Natural Gas Imported from Canada, ERA Opinion No. 29, at 3 (Mar. 27, 1980).

¹⁰⁵*Id.*

¹⁰⁶Northern Border Pipeline Co., FERC Docket No. CP74-290, Order Authorizing the Importation of Natural Gas (April 26, 1980.)

dent to import certain quantities of gas when lower cost domestic gas was available.¹⁰⁷

The barriers to increasing Canadian imports are primarily pricing and policy ones. It is suggested here that contracts for purchases of imported gas by United States companies, once approved by appropriate federal authorities, should be honored and the costs for such gas be allowed. A key question is how to arrive at import pricing formulae which will allow gas price escalation at reasonable rates which will be honored by all parties and are flexible enough to vary with rapidly changing market conditions. The U.S. and Canada are buying and selling gas at close distance across a friendly border, which has security advantages to the United States over other import alternatives such as importing oil over sea lanes from the Middle East. Both economies can benefit from a dependable gas market at appropriate prices and terms.

(b) Mexican Imports

New imports of Mexican gas began in 1980 at the rate of 300 MMcf per day.¹⁰⁸ Mexican reserves currently are estimated at about 84 Tcf of proven reserves and 400 Tcf of potentially available reserves. It is estimated that Mexican exports will range from .1 Tcf to 2.0 Tcf from 1981 through the year 2000.¹⁰⁹

The policy barriers to increased Mexican gas imports generally are similar to Canadian import barriers. However, there are some differences. Mexican gas resources appear to be larger than Canada's and are state owned.¹¹⁰ Mexico also may be reluctant to reach the same export levels as Canada because of (a) the internal political problems of selling too much gas to the United States; (b) the greater inflationary impact of exports on the Mexican economy; (c) Mexico's desire to use gas and oil reserves to build its own industrial base; and (d) the linkages between gas export policy and other Mexican/U.S. problems such as immigration policy which provides a further complication.¹¹¹ In addition, Mexico is likely to continue to seek price parity with other exporters. ERA already has recognized this problem by allowing Mexican gas the \$4.94/MMbtu price allowed for Canadian gas in 1981 but, ERA also noted that both countries' exports may be restricted to discourage United States' over-dependence on imports.¹¹²

The answers to these problems may be similar to those for Canadian export policy—recognition of the mutual benefits of a North American energy policy on an equal partner basis, establishing contractual arrangements mutually satisfactory to all partners and steady adherence to such contracts.

¹⁰⁷The Public Utility Commission of the State of California denied Pacific Gas and Electric Company an increase in rates to cover costs for purchased Canadian gas. Application for Authority to Revise Gas Rates and Tariffs Effective July 1, 1980, Under the Gas Adjustment Clause, Cal. P.S.C. Dec. No. 92304, at 13015 (filed May 28, 1980); Cal. P.S.C. Order Modifying Dec. No. 923042 and Denying Rehearing, Cal. P.S.C. Dec. No. 92642 (filed May 28, 1980). Gas Supply, *supra* note 7, at 18, 19.

¹⁰⁸Gas Supply, *supra* note 7, at 18, 19.

¹⁰⁹*Id.*

¹¹⁰*Id.*

¹¹¹See generally Joint Committee Print, *Mexico's Oil and Gas Policy: An Analysis*, 96th Cong., 1st Sess. (1978); Energy Users Rept. 20 (Mar. 8, 1979); B. Netschert, *Mexican Oil and Its Implications for United States Energy Policy*, *Aware* 2 (April 1979); T. J. Stewart-Gordon, *Mexico's Giants Enter Their Second Decade*, *World Oil* 61 (Feb. 1, 1981).

¹¹²*Supra* note 104; Opinion and Order Authorizing Payment of an Increased Border Price for Natural Gas Imported from Canada, ERA Opinion No. 31 (Apr. 21, 1981).

(c) *Liquefied Natural Gas (LNG)*

LNG is conventional natural gas which has been liquefied by reducing its temperature to minus 260°F. and its volume to 1/600 of that of gas in its vaporous state. This permits the transportation of large volumes of natural gas over great distances across oceans or other terrain unsuitable for pipelines as well as its efficient storage near markets.¹¹³

The United States has been importing LNG from Algeria with a contracted capability of slightly over 400 Bcf/year. On a worldwide basis, 6 countries with 1978 reserves of 199 Tcf currently trade LNG; and the 1978 estimated world-wide LNG resource base is 1955 Tcf located in some 22 potential exporting countries.¹¹⁴

LNG EXPORTING NATIONS: RESERVES & PRODUCTION

	Reserves— 1978 ¹ Tcf	Commercial Production— 1978 ² Tcf	Flared— 1977 ³ Bcf	1978 R/P
Current Exporters				
U.S., South Alaska ⁴	6	.1 ⁵	7 ⁵	56
Algeria	114	.3	174	242
Libya	27	.4	60	59
Abu Dhabi	20	.1	38	145
Brunei	8	.2 ⁵	35	34
Indonesia	24	.6	30	38
Potential Exporters				
Middle East				
Qatar	50	.05	94	500
Saudi Arabia	81	.1	1,320	57
Iran	436	1.7	986	162
Pakistan	19	—	—	—
Far East/Oceania				
Malaysia	23	.1 ⁵	63	141
Australia	30	.2	5	146
New Zealand	6	.06	2	97
South America				
Trinidad & Tobago	7	.2	79	25
Venezuela	42	.4	100	84
Colombia	5	.1	26	40
Chile	4	.3	100 ⁵	10
Ecuador	2	.1	30	15
Mexico	60	.9	143	58
Africa				
Nigeria	47	.6	740	35
Soviet Union	862	13.1	665	62
Canada ⁶	82	2.3	46	35

¹Average of estimates of *Oil & Gas Journal*, *World Oil* and *International Petroleum Encyclopedia*.

²Based on *Oil & Gas Journal*, February 26, 1979, p. 166.

³U.S., DOE, EIA, "World Natural Gas: 1977," *Energy Data Reports* (DOE/EIA-01333/77), 1979.

⁴Reserves and production data from A.G.A. reserves data.

⁵Estimated based on above references.

⁶Reserves and production based on data from the Canadian Petroleum Association.

¹¹³Gas Supply, *supra* note 7, at 20, 21.

¹¹⁴*Id.* For further information on LNG trade for these countries see 6 LNG Digest 10 (Oct. 1980).

The United States gradually should expand LNG imports for baseload and peak shaving purposes to 3-4 Tcf/year by the year 2000. This modest increase should not result in overdependence on foreign gas. At 4 Tcf/year, imports would be only 13% of the 30 Tcf/year of United States gas usage estimated by the year 2000 and such imports can come from diverse countries which provides substantial political stability of supply. While LNG is a foreign source of supply it has a number of advantages over other foreign sources of energy.

First, supply interruptions may be less likely with LNG than with oil because: (1) exporting countries must pay substantial debt service on expensive liquefaction facilities; this debt service creates financial pressure for continued LNG exports; and (2) world natural gas consumption rates are presently less than half of world oil consumption rates on a Btu equivalent basis. If this difference in consumption rates continues, world natural gas resources would be only about 20% depleted while world oil resources would be about 50% depleted by the year 2000.¹¹⁵ Thus, the future availability and price stability of imports may be greater for LNG than for oil.

Second, LNG has a more favorable balance of payments impact than imported oil. Typically, for each dollar of imported LNG, almost half (about 45 cents) is returned to the United States in payments for shipping, capital and other costs because United States' companies own some of the LNG tankers and share either in the ownership of the foreign LNG plant and equipment or participate in its financing. For oil, the amount returned is only 15 cents per dollar expended.¹¹⁶

Third, on a marginal (full) cost basis, LNG costs about one-third the price of electricity; *ie.*, generally no more than number two fuel oil refined from foreign crude oil at world price levels.¹¹⁷ Fourth, air, water and solid waste pollution from domestic LNG operations are relatively negligible.¹¹⁸

There are a number of export barriers to increased LNG imports: (1) some countries may wish to use LNG reserves for uses other than export such as for domestically consumed petrochemical feedstocks; (2) the United States must compete with other foreign buyers; (3) there are enormous capital costs associated with liquefaction—liquefaction facilities for the proposed South Alaska to Point Conception, California project, for example, are expected to cost \$770 million;¹¹⁹ and (4) gas reserves or excess gas production capacity may not be sufficient in some countries to support a project over its economic lifetime.¹²⁰ Barriers on the import side also are numerous. First, pricing formulae which are fair and acceptable to buyers and sellers alike must be established and recognized by all parties to provide reliable service. This can be difficult. In 1981, for instance, after many months of negotiations, the United States and Algeria failed to find a common pricing formula for the continued import of certain Algerian LNG. The Algerians were seeking a gas price *at Algeria* of parity with world oil—approximately \$6/Mcf.

¹¹⁵American Gas Association Energy Analysis: A Comparison of U.S. and World Remaining Gas and Oil Resources, 1979, at 1, 2 (January 19, 1979).

¹¹⁶American Gas Association, Energy Analysis, A Comparison of Foreign Energy Payments Resulting From Importation of LNG Versus Oil 1 (February 3, 1978).

¹¹⁷*Id.*

¹¹⁸See Part 1B(7) *supra*, for chart on relative fossil fuel pollution levels. Generally, LNG produces the same pollution as natural gas.

¹¹⁹American Gas Association, Gas Energy Review 12 (December 1980).

¹²⁰Gas Supply, *supra* note 7, at 21.

This price did not include the cost of transporting the gas to the United States and terminal and regasification costs—an additional \$1.50-\$2.00. The United States sought a price for LNG *delivered* to East Coast terminals comparable to alternative fuels available in the United States—such as Canadian gas imports at \$4.94/MMBtu or oil imports in the range of \$6.00/MMBtu.¹²¹ The price gap was too wide to close and negotiations temporarily were terminated.

The Algerian experience illustrates probably the greatest barrier to LNG imports, *i.e.*, the difficulty of arriving at a pricing formula acceptable to all parties to be applied over the life of the trade. Basically, the issue is one of proper escalation of price for a product being sold on the world market. If this problem can be resolved, LNG imports can increase modestly because the technical aspects of LNG trade are well proven.¹²²

Government policies toward LNG are another problem. In 1978, then DOE Secretary James Schlesinger discussed supplemental gas sources and concluded that long haul LNG (such as from Algeria) was "at the end of the priority line" of all of them.¹²³ A few days later, in two almost simultaneous decisions, the *El Paso Eastern Company* and *Tenneco Atlantic Pipeline Company* cases, ERA denied LNG import applications for Algerian "long haul" LNG.¹²⁴ In denying El Paso's import certificate, ERA appeared to promulgate a new standard of proof for LNG not contemplated by existing law. ERA found that the project failed the statutory test of being consistent with the public interest because it was unable to "find an overriding national or regional need for this gas."¹²⁵ ERA reasoned that the 1985 projected supply of domestic gas was adequate to meet firm national gas needs of around 12 Tcf.¹²⁶ This 1985 "adequate" supply, however, was significantly below the 1979 marketed gas supply of 19 Tcf. Thus, ERA limited its test to firm gas demands for high priority uses and made no allowance for expanded gas demand for the next six years—1979 to 1985. ERA's forecast was made despite the Department of Energy's own estimate that total United States energy demand would rise from 75.7 quads in 1977, to 94.6 quads in 1985, an increase of 24.9%.¹²⁷

4. Coal Gasification

United States coal reserves are estimated at some 458 billion tons (10,000 quads), one-half of which can be recovered under present technological and economic conditions. If only one half of that recoverable coal (2,500 quads) were used for gasification, it could supply current total U.S. gas consumption of approximately 20 quads (Tcf) annually for 124 years.¹²⁸ Gas made from coal could dis-

¹²¹See Stuart, *El Paso Comes in From the Cold*, *Fortune* 55, 56 (Mar. 23, 1981); Randal, *Collapse of Natural Gas Deal is Costly Despite U.S., Algerian Boasts*, *The Wash. Post*, Mar. 26, 1981, at A19. If rolled in rather than incremental pricing is used for LNG, the price impact on consumers is less and administering the pricing scheme is less burdensome. *Columbia LNG Corp.*, Opinion No. 622-48 F.P.C. 723, 729-730 (1972).

¹²²Gas Supply, *supra* note 7, at 21.

¹²³Brief of American Gas Association in Support of Application for Rehearing In The Matter of El Paso Eastern Co., at 2, ERA Docket No. 77-006-LNG (Jan. 19, 1979).

¹²⁴El Paso Eastern Co., ERA Docket No. 77-006-LNG, FERC Docket No. CP77-330 (Dec. 21, 1978); Tenneco Atlantic Pipeline Co., ERA Docket No. 77-010-LNG, Opinion No. 3 (Dec. 18, 1978).

¹²⁵*Emphasis added*, El Paso Eastern Co., *supra* note 124, at 64.

¹²⁶ERA, No. 77-006-LNG, *supra* note 124, at 45; see Brief, *supra* note 123, at 6, 7.

¹²⁷Brief, *supra* note 123, at 5, 6.

¹²⁸Gas Supply, *supra* note 7, at 22.

place oil in many stationary uses and thus make more oil available for transport purposes.

Coal gasification has a number of advantages over the use of coal to generate electricity. For example, (a) a high-Btu coal gasification process could produce 10% to 20% less carbon dioxide emissions than principal coal use alternatives—coal liquids and coal-fired power generation; coal gasification reduces carbon dioxide emissions because the concentrated carbon dioxide waste stream from a coal gasification plant can be captured for various uses including enhanced oil recovery;¹²⁹ (b) gas from coal can be transported efficiently and with minimal environmental impact through the existing gas pipeline/distribution system; (c) “in situ” coal gasification methods can be used (in which coal is “burned” underground, producing gas) which eliminates mining and minimizes environmental problems;¹³⁰ and (d) gasification requires lower capital costs per Btu of usable energy produced.¹³¹ Coal gasification technology has been known for many decades. But the United States has yet to operate its first high Btu coal gasification plant.

The immense cost of a coal gasification plant—nearly \$2.02 billion for the Great Plains project¹³² for instance—requires rolled-in pricing and assurance that pipelines can recover the cost of coal gas in their rates. These can be accomplished in any number of ways, but delays in finding proper solutions have been excessive. The Great Plains project, for example, has been involved in regulatory review and litigation since 1975.

In 1979, in Order No. 69, the FERC reversed an Initial Decision¹³³ by Administrative Law Judge Zimmet and issued a certificate of Public Convenience and Necessity under section 7 of the NGA to a partnership called “Great Plains Gasification Association” for the construction and operation of a coal gasification plant in Mercer County, North Dakota. This plant was to produce approximately 125,000 Mcf of coal gas per day, with a heating value of approximately 970 Btu per cubic foot (high Btu, pipeline quality gas).¹³⁴ The facility would utilize lignite as the fossil fuel for conversion to synthetic gas. This plant was to be a demonstration project within the definition of research, development and demonstration promulgated by FERC’s Order No. 566.¹³⁵

¹²⁹Fact Book, *supra* note 25, at 16. Some have raised the possibility of environmental dangers from by products of coal liquids and coal gasification. See *Oak Ridge Research Uncovers Hidden Danger in Coal Liquids*, *The Energy Daily*, Apr. 11, 1981, at 4, col. 1.

¹³⁰Gas Supply, *supra* note 7, at 22.

¹³¹*Id.* at 49.

¹³²This project is described in Great Plains Gasification Assoc., FERC Opinion No. 69, Doc. No. CP78-391, at 1-6 (Nov. 21, 1979); rehearing denied, FERC Opinion No. 69-A (Jan. 21, 1980). See also T. Bindra, in chapter on *Pipeline Gas Supplies*, in *Regulation of the Gas Industry* (1981).

¹³³*Id.* Great Plains Gasification Assoc. FERC Opinion No. 69. Great Plains Gasification Associates, FERC Docket No. CP 78-391 (Nov. 21, 1979).

¹³⁴Pipeline quality gas typically is in the range of 1000 Btu. Mcf. Because gas made from coal is not “natural gas” under section 2(5) of the Natural Gas Act, 15 U.S.C. § 717a (5) (1976), it is not subject to FERC jurisdiction until it is commingled with natural gas, and such mixed gas is transported for resale in interstate commerce for ultimate public consumption. 15 U.S.C. § 717a (1976). See *El Paso Natural Gas Company FPC Docket No. CP73-131*, Opinion No. 663 (Sep. 4, 1973), *Transwestern Coal Gasification Co. FPC Docket No. CP73-211*, Opinion No. 728 (Apr. 21, 1975); *Henry v. FPC*, 513 F.2d 395, (D.C. Cir. 1975), *Pub. Serv. Comm’n of New York v. FPC*, 543 F.2d 392 (D.C. Cir. 1976).

¹³⁵Order Prescribing Changes in Accounting and Rate Treatment for Research, Development and Demonstration Expenditures, FERC Order No. 566, Docket No. RM 76-17 (June 3, 1977).

One of the major goals of the Great Plains coal gasification project is to demonstrate the technical, environmental and economic feasibility of producing high Btu gas from coal. Because this project is the first of its kind in the United States, it faces various uncertainties. For example, techniques for producing gas from coal may prove less efficient than estimated and the project could have unanticipated impacts on the environment or incur cost overruns. The FERC recognized that such uncertainties may deter entrepreneurs from undertaking coal gasification investments by approving the following special tariff provisions for the Great Plains project (but cautioned that such provisions may not be approved for future coal gasification projects):¹³⁶

1. Ratepayers of the project sponsors would guarantee the repayment of and interest on the debt in all circumstances and guarantee return on equity in most circumstances except where management was imprudent. The debt costs could be recovered from the rate payers on an accelerated basis of five years if the project were never completed.
2. Pipeline purchasers of gas from Great Plains would be permitted to pass through the costs of such gas.
3. The gas may be priced on a rolled-in basis.
4. The project sponsors would be permitted to levy a surcharge during construction to recover interest and financing costs on debt, a return on equity and related taxes and similar carrying charges incurred by Great Plains under a coal purchase agreement. The purchasing pipelines would be allowed to recover the surcharge in their respective rates during construction.
5. The FERC reduced the project sponsors' requested return on equity from 15% to 13% and required a periodic rate of return with a review commencing one year after the in-service date and then every three years thereafter.
6. Great Plains specifically was required to seek federal loan guarantees and file appropriate tariff amendments.¹³⁷

On appeal of FERC's Order 69¹³⁸ by General Motors Corporation, various state agencies and others, the United States Court of Appeals for the District of Columbia Circuit held that FERC has exceeded its jurisdiction in issuing Order 69 and remanded the case to FERC for further proceedings (if necessary). In doing so, the court stated:

In short we are dealing with an attempt by FERC to utilize its certification and rate setting power to make possible financing for the prospective construction of a non-jurisdictional, commercial-size coal gasification plant.¹³⁹

¹³⁶Great Plains Gasification Associates, FERC Opinion No. 69, *supra* note 132, at 62-77; FERC Opinion No. 69A, *supra* note 132, at 5-6. Other proposed coal gasification projects have suffered financial hurdles as well. See *Texas Eastern Unit Denied Permission to Recoup Planning Expenses From Customers*, XI IGT Highlights No. 7, 2 (Chic., Ill.) (Mar. 30, 1981).

¹³⁷Great Plains Gasification Associates, FERC Opinion No. 69, *supra* note 132, at 62-77.

¹³⁸Office of Consumers' Counsel v. FERC, Nos. 80-1303, 80-1316, 80-1321, 80-1326, (D.C. Cir. Dec. 8, 1980).

¹³⁹*Id.* at 22.

The court went on to say that FERC also had exceeded its statutory authority in "regulating its [the plant's] construction and operation (or non-operation)," and that a review of legislative history confirmed this conclusion.¹⁴⁰

In August 1981, President Reagan approved a \$2.02 billion loan guarantee for the Great Plains Project, thus insuring that adequate financing will be provided to construct the first United States' high Btu coal gas facility.¹⁴¹

5. Synthetic Natural Gas (SNG) from Liquid Hydrocarbons

The processing of liquid hydrocarbons such as naphtha or natural gas liquids (NGLs) to provide synthetic natural gas (SNG) takes place in fourteen U.S. facilities which operate either as base-load facilities or as a seasonal "peak shaving" supply source.¹⁴² Peak shaving is the supplying of fuel gas for a distribution system from an auxiliary (*i.e.*, not the usual pipeline) source during periods of maximum demand, when the primary source is not adequate, such as on the coldest days of the year. Such peaking facilities near the point of consumption allow distribution companies to contract for primary gas supplies at lower peak day volumes, thus reducing gas purchase costs.

The total daily design capacity of all SNG facilities is roughly .14 Tcf. Because most SNG plants are not designed for year-around operation, actual operating levels produced only about .1 Tcf in 1980.¹⁴³ Although the total worldwide resource base of NGLs which provide feedstock for these plants is likely to grow during the 1980s, U.S. production estimates of SNG range from .1 Tcf to .5 Tcf through the year 2000 because of its higher cost compared to some alternate sources of gas such as conventional lower 48 state gas production.¹⁴⁴

In *Algonquin SNG, Inc.*,¹⁴⁵ the FPC held that SNG is not "natural gas" under Section 2(5)¹⁴⁶ of the NGA. Thus, FERC has no direct jurisdiction over SNG or the facilities which produce it. FERC jurisdiction attaches to SNG, however, once it becomes mixed with natural gas flowing in interstate commerce.¹⁴⁷ At that point those facilities used to transport it, the rate at which it is sold and matters relating to the transportation and sale for resale of such gas in interstate commerce are subject to the FERC's control.

¹⁴⁰*Id.* at 23. Sponsors of the project petitioned FERC for approval of a settlement offer, *see* Motion of Applicants for approval of Offer of Settlement, FERC Docket Nos. CP78-391, CP75-278 and CP77-556 (Apr. 10, 1981), approved by FERC, Opinion No. 119, Opinion and Order Approving Rate Settlement with Modifications (Apr. 30, 1981).

¹⁴¹¶ The Energy Daily, August 6, 1981, at 1, col. 1.

¹⁴²Gas Supply, *supra* note 7, at 35. Naphtha is any one of various volatile, often flammable, liquid hydrocarbon mixtures used chiefly as solvents and diluents and as raw materials for conversion to gasoline and substitute or synthetic natural gas (SNG). For various definitions *see* American Gas Association, Glossary for the Gas Industry (1981).

¹⁴³Gas Supply, *supra* note 7, at 35.

¹⁴⁴*Id.*

¹⁴⁵Opinion No. 637, 48 FPC 1216, 1221 (1972); *See also* Algonquin SNG, Inc., Opinion No. 637A, 49 FPC 345 (Feb. 6, 1973), regarding SNG cost pass-through; *see also* Henry v. FPC, 513 F.2d 395 (D.C. Cir. 1975).

¹⁴⁶15 U.S.C. § 717a (1976). Section 2(5) reads as follows: "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas." *See* note 134, *supra*, for cases involving at what point FPC/FERC jurisdiction attaches to manufactured gas.

¹⁴⁷*Id.*

Prior to January 28, 1981, price regulation of NGLs used to produce SNG was authorized under the Emergency Petroleum Allocation Act of 1973 (EPAA)¹⁴⁸ and administered by ERA. On January 28, 1981, however, President Reagan signed Executive Order 12287,¹⁴⁹ which exempted all crude oil and refined petroleum products (including NGLs) from EPAA price and allocation controls.

A major barrier to further development of SNG is its higher cost compared to other supplemental supplies of gas. In considering increased SNG energy supplies, the advantages of SNG should be compared to oil imports. SNG currently offers substantial environmental advantages and may, in the long run, provide a worldwide energy supply alternative to OPEC oil.¹⁵⁰

6. Unconventional Sources of Gas

There is a very large potential resource of unconventional gas. It can come from such renewable sources as biomass (plant life including aquatic and land wastes and crops)¹⁵¹ or non-renewable sources such as western tight sands¹⁵², Devonian shale,¹⁵³ and geopressed brine.¹⁵⁴ At this stage in the development of gas from unconventional sources, the primary barrier to further supply is lack of a sufficient research and development (R&D) effort. For example, research is necessary for Devonian shale and western tight sands to determine the extent of the resources, extraction methods and cost projections. But adequate support for such R&D effort has not been forthcoming. Although the gas industry continues to provide about 25% of the total energy consumed in the United States and approximately 33% of domestic U.S. energy production, gas received only 5.1% of the DOE FY 81 research and development budget. Electricity, by contrast, supplies less than 8 quads of energy but received 42.5% of this budget or a ratio of over 8 to 1 compared to gas; in the FY 82 budget this ratio rose to 13 to 1.¹⁵⁵

a. *Tight Formation Gas.* Tight formation gas is produced from low permeability formations such as western tight sands and eastern Devonian shales. The total resource base for tight sands is vast, perhaps over 400 Tcf. Recoverable resource estimates range from 30 Tcf with existing technology at a market price of \$3.12 in 1979 dollars to 150 Tcf with a market price of \$6.00 and advanced technology.¹⁵⁶ Total current production is about .9 Tcf. Its low flow capacity means that further research and development will be necessary to make tight sands gas production more efficient, which will increase its attractiveness as a gas supply source.¹⁵⁷

¹⁴⁸15 U.S.C. § 751 (1976). There were limits, however, to FEA/ERA's authority. See, e.g., *Consumers Power Co. v. FEA*, 413 F. Supp. 1007 (E.D. Mich. 1976), in which FEA was denied authority to directly condition SNG feedstock allocations on limitations of load growth and incremental pricing.

¹⁴⁹Executive Order No. 12287, 46 Fed. Reg. 9909 (Jan. 30, 1981).

¹⁵⁰Gas Supply, *supra* note 7, at 35, 36.

¹⁵¹*Id.* at 37, 38.

¹⁵²*Id.*

¹⁵³*Id.* See also 18 C.F.R. § 271.703 (1981).

¹⁵⁴*Id.*

¹⁵⁵American Gas Association unpublished staff analysis of FY 1981 DOE research and development budget. For 1982 budget figures, see American Gas Association, XIV Washington Letter 1 (March 27, 1981).

¹⁵⁶Gas Supply, *supra* note 7, at 31.

¹⁵⁷*Id.*

The FERC has taken steps to raise prices for gas from tight formations. In August 1980, the FERC set a maximum special incentive price for tight sands at \$4.55 (200% of the Section 103¹⁵⁸ new onshore ceiling price under the NGPA).¹⁵⁹ The Devonian shale definition was changed by the FERC in 1981 to allow gas produced in sandstone or silt stringers to qualify as higher cost gas under Section 107 of the NGPA.¹⁶⁰

b. Gas from Biomass. Biomass includes all growing plant life. It is of two types, aquatic (such as giant kelp, water hyacinths and algae) and land biomass (such as from pines and hardwoods, grasses and crops, and wastes from forestry operations and crop harvesting and processing). While there currently is no commercially available gas from biomass projects (due to the need for research into efficient harvesting and conversion techniques), by the year 2000 the total U.S. potential resource is estimated at from 35 to 110 Bcf/year.¹⁶¹

c. Urban Waste and Animal Residue. Urban waste and animal residue include urban refuse, industrial waste, sewage, and animal manures. Current production capability is approximately 1.9 Bcf/year, and by the year 2000 could be from 230 to 800 Bcf/year. Currently, there are 11 landfill methane recovery projects in operation. Three produce pipeline quality gas.¹⁶²

One of the questions faced for each new gas source is whether it will be classified as "natural gas" under Section 2 (5) of the NGA and thus become subject to FERC's jurisdiction. In *Natural Gas Pipeline Co. of America*,¹⁶³ the FPC held that unmixed gas produced through the anaerobic processing of animal waste was not "natural gas". Thus, the gas and the facilities used for its production were non-jurisdictional. This decision followed the FPC's reasoning in earlier cases such as *Algonquin SNG, Inc.*,¹⁶⁴ (in which gas produced from the reformation of naphtha was held not to be "natural gas"); and *El Paso Natural Gas Co.*¹⁶⁵ (in which "coal gas" was held not to be "natural gas" because while it contained trace elements of methane, it underwent a basic change in molecular structure).

Other potential sources of methane and a summary of their potential production estimates by the year 2000 are listed *infra*.¹⁶⁶

The maximum production of unconventional sources by the year 2000 is probably limited to the midpoint in the range of from 635 Bcf to 4200 Bcf, or approximately 2400 Bcf/year.

¹⁵⁸15 U.S.C. § 3303 (Supp. II 1978).

¹⁵⁹FERC Regulations Covering High-Cost Natural Gas Produced From Tight Formations, 18 C.F.R. § 271, 273, 274, (1980).

¹⁶⁰Section 107 is found at 15 U.S.C. § 3317 (Supp. II 1978). Final Rule on Defining and Deregulating Certain High Cost Gas, FERC Docket No. RM79-44, Order No. 78 (1980), 45 Fed. Reg. 28092 (Apr. 28, 1980).

¹⁶¹Gas Supply, *supra* note 7, at 37, 38.

¹⁶²For a list of these sites, see American Gas Association, 8 *Gas Energy Review* 7, at 11 (Apr. 1980).

¹⁶³Natural Gas Pipeline Co. of America, FPC Docket No. CP 75-147, Opinion 763 (May 24, 1976).

¹⁶⁴*Supra* note 145.

¹⁶⁵El Paso natural Gas Co., *supra* note 134.

¹⁶⁶Gas Supply, *supra* note 7, at 42.

SUMMARY OF PRODUCTION ESTIMATES FOR NONCONVENTIONAL NON-RENEWABLE SOURCES (Bcf)

Source	Year	
	1990	2000
Gas From Coal Seams	60-240	290-1,400
Geopressured Gas	5-100	20-1,000
SNG From Peat	30-180	180- 900
SNG From Oil Shale	25- 90	100- 720
<i>In situ</i> Coal Gasification	0- 45	45- 180
Total Range	120-655	635-4,200
Maximum Probable Supply	350	2,400

C. The Financial Barriers

To provide the country's gas supply needs of from 25 to 32 Tcf by the year 2000, the gas industry must spend about \$400 billion (in 1980 dollars). That is over six times the total gross gas industry plant investment of \$60 billion.¹⁶⁷ Approximately 30% of this amount (\$124 billion) will be needed for traditional utility pipeline/distribution construction and maintenance activities. The rest (\$277 billion), will be for major gas supply projects.

To attract and generate that capital is a major challenge. Such capital must be raised in an environment of inadequate utility company earnings, substantial inflation, higher gas prices, loss of gas sales volumes, restrictive advertising laws and inadequate depreciation allowances.

1. Inadequate Utility Company Earnings

Most of the funds which gas utilities will need to finance new facilities must come from the sale of new security issues (debt and equity). Such sales cannot be accomplished without adequate earnings to attract investors. "Earnings" or "return," is the amount of money a regulated gas company is allowed to earn over and above its operating expenses, depreciation expenses and taxes.¹⁶⁸ Rate of return is expressed as a percentage of the company's "rate base," which is the legally determined net valuation of its property.¹⁶⁹

¹⁶⁷Address by Robert H. Willis (Chairman and President, Connecticut Natural Gas Corporation and Chairman A.G.A.) before the National Association of Regulatory Utility Commissioners 92nd Annual Convention, Houston, Texas (Nov. 12, 1980.)

¹⁶⁸See generally W. Gallagher, chapter on *Rate of Return*; and chapter on *The Specifics of Regulation, General Principles Applicable to Utility Rates* in Regulation of the Gas Industry (1981).

¹⁶⁹*Id.*

Unless earnings on its securities are competitive in current market conditions, a utility cannot attract the necessary investors to raise sufficient capital. A 1980 survey of 50 gas distribution companies showed that common stocks of 88% of the utilities were below book value. Thus, if additional common stock were issued to raise capital, existing stockholders would find their stock diluted; indeed, one Public Service Commission has referred to this as "confiscation."¹⁷⁰ For those surveyed, profits averaged about 5% of revenues. Typical average actual return on common stock equity was 11.7% for these companies compared to 13.5% allowed in their most recent rate case.¹⁷¹

This difference between what was "allowed" and actually "realized" is a major problem for utilities during periods of rapid inflation. Inadequate regulatory treatment of incurred costs contributes substantially to the low esteem in which the marketplace holds common stocks of many gas distribution companies. The difference in return required to correct this problem is not great. For a typical hypothetical company it comes to 38 cents per customer per month.¹⁷²

~ However, even if the "allowed" return on equity were realized it probably would not cure investors' lack of enthusiasm for gas utility stocks. Higher rates of return on equity also are essential, especially as applied to an original cost rate base. Executives surveyed said that a 15%-16% return was the minimum necessary to maintain supply and service programs.¹⁷³ This would require an additional 37 cents per customer per month.¹⁷⁴ Thus, a total of only 75 cents per customer per month (38 cents plus 37 cents) represents the difference between a financially sound gas utility and one with serious future problems. This 75 cent increase would add only 1-3% to the customer's bill but would keep the gas distribution company financially sound.

As one utility executive has stated:

The result of poor earnings is an increased cost of capital for utilities because: it encourages debt financing over equity financing (companies are inclined to borrow rather than sell new stock below book); and weakens the company's capital structure by raising the debt-equity ratio and reducing the interest coverage ratio (ratio of earnings to interest on debt). This in turn tends to lower the utility's bond rating which requires the utility to pay higher interest rates which result in increased capital costs to stockholders and ratepayers.¹⁷⁵

Thus, while providing lower utility company rates may be appealing to regulators in the short run, in the long run it may increase costs to ratepayers and can reduce the quality or adequacy of service. If a utility's capital costs are greater, constructing new facilities is more expensive and rates must rise. "For example, if a typical class A utility . . . is financing \$1 billion in new plant capacity, a two

¹⁷⁰An unpublished survey by the American Gas Association, 1980. See also *Re Public Service Co. of N.M.*, 8 PUR 4th 113, at 128 (1975); see also Smartt, *A Problem in Equity and a Proposed Solution*, 106 Pub. Util. Fort. 2, at 4 (July 17, 1980), and *Progress of Regulation*, 92 Pub. Util. Fort. 4, at 73 (March 1, 1979).

¹⁷¹American Gas Association survey, *supra* note 170. See also remarks of Robert H. Willis re "creeping expropriation" of gas utility stocks in *A.G.A. Chairman Charts Utilities' Decline*, *The Energy Daily*, at 2 (June 11, 1981).

¹⁷²*Id.* Address of Robert H. Willis, *supra* note 167.

¹⁷³*Id.*

¹⁷⁴*Id.*

¹⁷⁵Testimony of John J. Curtis, Director of Taxes, Pacific Lighting Corp., on behalf of the American Gas Association, on 1980 Tax Cut Proposals, at 7, before the House Committee on Ways and Means, 96th Cong. 2d Sess. (July 31, 1980). See also *The Cost of Not Raising Utility Bills*, *The N.Y. Times*, Mar. 19, 1981, at 26, col. 1.

percentage point increase in its cost of capital will amount to a rate increase of \$20 million a year for the next thirty years—well into the next century."¹⁷⁶

(a) The Price Squeeze: Higher Rates and Uncollectables.

Higher gas prices significantly have hurt some gas companies' earnings. When producers raise prices and pass them on to the pipeline and distributor it is the distributor who must collect them. The difficulty in collecting higher gas bills revolves around two groups of people—those who are unable to pay and those who are unwilling to pay. For those who are unable to pay, some federal and state government aid programs have been developed to assist needy customers.¹⁷⁷

The problem of customers who refuse to pay their bills is a fast-growing phenomenon. There are substantial numbers of people who believe that utility service should be free or that bill-paying is a game to be played with the utility.¹⁷⁸ They have been aided by governmental rules requiring notices and other procedures before gas service can be terminated. For example, such rules may prohibit the utility from requiring security deposits.¹⁷⁹ More recently, gas distributors have been faced increasingly with rules prohibiting winter shut-offs of residential gas service. It should be recognized, that these rules can lead to postponement of payments by large segments of the population to the point where, when Spring arrives, they are faced with bills totalling hundreds of dollars which they cannot pay. For example, Michigan Consolidated Gas Company's uncollectable accounts in Detroit rose to over \$15 million annually in 1980—some 7.7% of their accounts.¹⁸⁰

(b) Conservation and Other Sales Volume Losses.

A second factor contributing to inadequate earnings is a reduction in sales in many "mature" market areas. The industrial base of some areas of the North and East is being eroded. In addition, there are substantial load losses due to conservation. According to a 1981 survey, gas conservation (defined as the percentage

¹⁷⁶Navarro, *Electric Utility Regulation and National Energy Policy*, Regulation of the Gas Industry Vol. IV Regulation 20 (Jan.-Feb. 1981).

¹⁷⁷Address by Arthur R. Seder, Jr., Chairman, President and C.E.O., American Natural Resources Company, before the A.G.A. Third Annual Legal Forum, Colorado Springs, Colorado (July 1980) [hereinafter cited as Seder Address.] For an example of the energy assistance programs, see the Home Energy Assistance Act of 1980, 42 U.S.C. § 8601. Also the Low Income Energy Assistance Program, 45 C.F.R., Part 260, 45 Fed. Reg. 36810 (1980) authorizes Federal grants to states "to provide assistance to eligible households to offset the rising costs of home energy that are excessive in relation to household income." The funds for this program are to come from revenue produced by the "windfall profits" tax, 26 U.S.C. § 4986 (1980). See also the Energy Crisis Intervention Program, administered by the Community Services Administration, which provides funds to conduct community activities, i.e., mobilization and organization of community energy conservation education programs and direct services such as providing blankets, temporary shelter and clothing. See also Funding Requirements for FY81 Energy Crisis Intervention Program, 45 Fed. Reg. 73054 (1980). Also, a number of states, such as Kentucky, Michigan, Nebraska, New Jersey and Ohio, have a low income fuel assistance program.

¹⁷⁸Seder Address, *supra* note 177.

¹⁷⁹*Id.* Sections 303 and 304 (15 U.S.C. §§ 3203, 3204) of the Public Utility Regulatory Policies Act of 1978 (PURPA) required each state regulatory authority to conduct a hearing to consider gas service termination standards set forth in § 3204. In an order unrelated to PURPA standards, the Michigan Public Service Commission instituted a Winter Protection Plan. Under this plan, the Michigan Consolidated Gas Co. was prohibited from requiring a security deposit from new residential customers. Mich. Pub. Serv. Comm'n, Order No. U-4240 (Oct. 28, 1980).

¹⁸⁰Mich. Publ. Serv. Comm'n Order No. U 4240 (Oct. 28, 1980).

decline in gas use per customer adjusted for weather from a 1973 baseline) has increased nearly every year since the 1973 oil embargo. In the residential sector, for instance, gas use declined at a rate of 2.7% per year, resulting in 15% less gas consumption during 1979 compared to the 1973 base line.¹⁸¹ In the Detroit area, residential consumption in 1980 was about 17% less per customer and industrial consumption about 30% less since gas usage peaked in 1973. And these figures do not include the effects of prospective furnace efficiency retrofit programs that could reduce residential usage in that service area by another 20%.¹⁸²

In this decade, conservation is expected to continue to increase but at a slower rate. From the standpoint of the public interest, sales volume reductions from conservation should be applauded. In theory, if rate regulation were prompt and precise, these reductions in sales should not adversely affect earnings. It is difficult, however, to convince regulatory authorities that reductions in usage should be projected forward as a part of the cost of service. However, any lag in recognizing declines in sales may adversely affect earnings.

Another consequence of declining market demand is that distributors may be unable to take all of their required minimum volumes of gas from pipelines. Typically, contracts for the purchase of gas between producers and pipelines and large distributors served include "take-or-pay-for" clauses.¹⁸³ Unless utilities are permitted to reflect the cost of take-or-pay-for provisions in their rates, their earnings will suffer. One industry leader has suggested that:

[P]ipelines simply cannot continue to contract for gas on the basis of taking a high percentage of the open-flow of the wells. We must return to a practice of contracting in which takes are based upon reserves, with longer periods allowed for depletion of the fields or . . . if a distributor's decline in market requirements is permanent, a reduction in its pipeline contract obligation might be negotiated.¹⁸⁴

2. Overcoming the Regulatory Dilemma

Federal and state regulators of gas utilities face a difficult challenge. They must develop regulatory formulae fair to both utility company investors and to ratepayers. On the one hand, utilities can demonstrate their need for higher rates of return. On the other hand, rate payers naturally resist increased energy costs. Edward P. Larkin, past Chairman of the National Association of Regulatory Utility Commissioners (NARUC)¹⁸⁵ has pointed out:

If the investor-owned utility complex is to survive in the 1980s, regulators will have to come to grips with the realities of the marketplace. Beyond question, they are going to find themselves caught between a rock and a hard place. Public outrage against regulators caused by high rates will not be any more virulent than the wrath which will be visited

¹⁸¹American Gas Association, *Energy Analysis: A Survey of Actual and Projected Conservation in the Gas Utility Industry: 1973-1990*, at 1, 2, 1981-3 (March 20, 1981).

¹⁸²Seder Address, *supra* note 177.

¹⁸³For a discussion of take-or-pay clauses, see Howell, *Gas Purchase Contracts*, Southwestern Legal Foundation Fourth Annual Institute on Oil and Gas Law and Taxation 151, 170 (1953); *Treaties* § 724.5; cited in Williams and Meyers, *Manual of Oil and Gas Terms* 454 (4th ed. 1971).

¹⁸⁴Seder Address, *supra* note 177.

¹⁸⁵NARUC is a trade association, located in Wash., D.C., which represents Federal and state regulators.

upon them for lack of service. All across the nation, utility companies are currently deferring plants, cutting back on construction, cutting maintenance costs, and pushing hard for increased productivity.¹⁸⁶

In examining this investor-ratepayer dilemma, there appears to be a gap between what leading energy forecasters and utilities are saying about energy prices, and the public's perception of such prices. There is a growing consensus among experts that energy prices will rise and take a greater proportion of disposable personal income and living standards may fall. In summarizing common themes in recent leading energy forecasts, one commentator stated:

[T]here are no 'quick fixes' and there are no free lunches. The challenge is for the United States to adopt policies that can most cheaply and cleanly lead producers and consumers to adapt to the inevitable increases in the cost of energy. Conservation plays an important role . . . but it alone cannot solve our energy problems. Nor can solar energy be counted upon to make up the difference.¹⁸⁷

The public, on the other hand, is skeptical of the need for utility rate increases. Rate hearings, spread over many months with thousands of pages of technical documents, do not clearly explain the reasons for allowing or rejecting such increases.

As one possible solution to this regulatory dilemma, it has been suggested that public utility commissions in each state or regulatory jurisdiction open a dialogue with ratepayers and utilities by creating a Public Understanding Advisory Committee consisting of representatives from gas utilities, the media, consumer groups, environmentalists and others and chaired by a commission official.¹⁸⁸ Such committees could hold informal sessions to explain basic facts covering past (not present) rate cases and the reasons for the regulators' decisions. This could improve public understanding of the regulatory process.

3. Advertising Expenses as a Cost of Service Component

Laws or policies that prevent a gas utility from including advertising expenses in the utility's cost of service should be re-examined. Utility advertising is regulated at both Federal and state levels. Under Section 303¹⁸⁹ of the Public Utility Regulatory Policies Act of 1978 (PURPA)¹⁹⁰ for example, each state regulatory authority with jurisdiction over gas utilities was required to conduct a public hearing by November 1980, to consider approving the following advertising standards:

(2) Advertising.—No gas utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional . . . advertising . . .

¹⁸⁶Larkin, *A Debt to Tomorrow*, 107 Pub. Util. Fort. 3, 15 (Jan. 29, 1981).

¹⁸⁷Joskow, Book Review, *America's Many Energy Futures—A Review of Energy in America's Future*, The Bell Journal of Economics 377, at 398 (Spring 1980).

¹⁸⁸Address by C. C. Ingram, Chairman, Oklahoma Natural Gas Co., a Division of Oneok Inc., to NARUC Executive Committee (February 28, 1980).

¹⁸⁹15 U.S.C. § 3203 (Supp. II 1978).

¹⁹⁰16 U.S.C. §§ 2601-2645 (Supp. II 1978).

Section 304(b)(1)(C) of PURPA defines promotional advertising as follows:

The term "promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of a gas utility or the selection or installation of any appliance or equipment designed to use such utility's service.

However, section 304(2) provides that: "promotional advertising" does not include—

(A) advertising which informs natural gas consumers how they can conserve natural gas or can reduce peak demand for natural gas,

(E) advertising which promotes the use of energy efficient appliances, equipment or services . . .¹⁹¹

Such advertising standards, which have been adopted by some states,¹⁹² prevent utilities from recovering as a part of their cost of service certain useful promotional advertising. One example is advertising informing potential consumers of the advantages of gas service including lower costs compared to competing fuels. Advertising furthers the use of more efficient appliances which can yield many years of energy savings. It also can help increase the number of customers served, thus spreading a gas systems' fixed costs across a wider base, resulting in lower fixed costs per customer. As residential usage declines as a result of conservation efforts, the volumes of gas so saved should be sold to new residential customers who can benefit from the use of a more efficient energy. Otherwise, existing customers may fail to reap sufficient financial benefit from their conservation efforts.

While a gas distributor is a monopoly in the sense that it has exclusive legal rights to market gas utility service in an area, it still must compete vigorously with another monopoly, the electric utility, and unregulated competitors, such as fuel oil, coal, and liquefied petroleum dealers. When a gas utility is prevented from advertising it can be placed at a disadvantage compared to other fuels. For instance, electric utilities benefit from the continual promotion of their product by large manufacturers of thousands of electrical devices such as General Electric Corp. and Westinghouse Electric Corp. Gas appliance manufacturers generally are not of comparable size. Fuel oil dealers benefit from the advertising of large national and international companies. As Justice Cardozo said in *West Ohio Gas Co.*:¹⁹³

The suggestion is made that there is no evidence of competition. We take judicial notice of the fact that gas is in competition with other forms of fuel, such as oil and electricity. A business never stands still. It either grows or decays. Within the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes as for others.¹⁹⁴

¹⁹¹15 U.S.C. §§ 3203, 3204 (Supp. II 1978).

¹⁹²According to a survey by the National Association of Regulatory Commissioners, STATE COMMISSION PROGRESS UNDER PURPA OF 1978, 6 (Dec. 1980), 24 states have adopted such standards. See, e.g., *Miller Gas Co.*, Docket No. 770496 - GU(CR), Order No. 8304 (May 10, 1978) in which promotional advertising was disallowed in Florida; *National Fuel Gas Distribution Corp.*, 28 PUR 4th 42, Opinion No. 79-8 (1979), in which promotional advertising was disallowed in New York.

¹⁹³*West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63 (1935). Another problem is whether a public service commission legally may bar a utility from discussing controversial public policy issues in billing envelopes. See *Consolidated Edison Co. of N.Y., Inc. v. Pub. Service Comm'n*, 447 U.S. 557 (1980); *Central Hudson Gas and Electric Corp. v. Pub. Service Comm'n*, 447 U.S. 557 (1980).

¹⁹⁴*West Ohio Gas Co.*, 294 U.S. 63, at 72.

4. Regulation of Non-Jurisdictional Activities of Gas Utilities

Gas utilities are diversifying into non-utility or quasi-utility areas to lessen risks, increase profits, develop their own gas supply sources and improve their corporate image.¹⁹⁵

At the federal level, public utility diversification is regulated by the Public Utility Holding Company Act of 1935,¹⁹⁶ which provides for registration, limiting of holding companies to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate to the operations of such integrated public-utility system," and other requirements.¹⁹⁷

At the state level, public utility commissions generally review utility company diversification to prevent utility company earnings from being used to finance unrelated ventures to the detriment of utility service. Some state commissions regulate diversification directly, such as in New York, where Public Service Law § 107¹⁹⁸ provides:

Except with the consent and approval of the public service commission first had and obtained, no public utility shall use revenues received from the rendition of public service within the state for any purpose other than its operating, maintenance and depreciation expenses, the construction, extension, improvement or maintenance of its facilities and service, the payment of indebtedness and interest thereon, and the payment of dividends to its stockholders.¹⁹⁹

Other states regulate diversification indirectly such as by limiting approval of security issuances to specified purposes such as a "proper corporate purpose" which would serve "the public interest."²⁰⁰ Few states, however, have statutory authority to regulate the reinvestment of earnings from utility operations or non-utility operations.²⁰¹

One problem some gas utilities face when diversifying is that state utility commissions, faced with rising rates, find it tempting to use profitable non-utility earnings to justify what otherwise would be an inadequate return on the utility company's operations.²⁰² In contrast, some commissioners have recognized the

¹⁹⁵For a discussion of this subject, see J. Chase and D. Cycon, chapter on *Regulatory Treatment of Non-Utility Functions in Regulation of the Gas Industry* (1981).

¹⁹⁶15 U.S.C. §§ 79-79z-6 (1976).

¹⁹⁷*Id.* Section 11(b)(1), 42 U.S.C. § 79 (1976).

¹⁹⁸N.Y. Public Service Law § 107 (McKinney).

¹⁹⁹*Id.*

²⁰⁰*See, e.g.*, CAL. PUB. UTIL. CODE §§ 816, 824; CONN. GEN. STAT. ANN. § 16-43; FLA. STAT. ANN. § 366.04; ILL. REV. STAT. ch. 111 2-3 § 20; IND. CODE § 8-1-2-76; KY. REV. STAT. § 278.300; MICH. COMP. L. ANN. § 460.301; N. C. GEN. STAT. § 62-160; N.J. STAT. ANN. § 48-3-7.1; OHIO REV. CODE ANN. § 4905-40; PA. STAT. tit. 66, § 124; TENN. CODE ANN. § 65-409; W. VA. CODE § 32-2-13; WISC. STAT. ANN. § 184.01. Commission approval is not required in all states for all sources of investment funds, however. For example, while the California commission may limit use of security-derived funds, the court has held that advisability of diverting profit from investment dividends into other areas is a matter for the utility's management to decide, not the commission. *Pacific Tel. & Tel. Co. v. P.U.C.*, 4 Cal. 2d 822, 215 P.2d 441 (1950). Cited in Chase and Cycon, *supra* note 195, at n. 32.

²⁰¹"Effective regulation in this regard requires appropriate accounting procedures to segregate the non-utility earnings. This situation is discussed in Report of the Ad Hoc Committee on Non-Utility Investment, National Association of Regulatory Commissioners (Wash., D. C. 1972). The report also gives a good general introduction and overview of utility investment in non-utility areas"; cited in Chase and Cycon, *supra* note 195, at 32.

²⁰²Seder Address, *supra* note 177.

necessity for and the value of non-utility operations to the ratepayers. The Wyoming Public Service Commission, for instance, recognizes that utilities can obtain lower cost gas by operating their own gas exploration and development companies and therefore "increased the revenue requirement for one utility by the amount of drilling and associated expenditures (without adjustments), and required costs to be borne by each class of customer in direct proportion to use by class."²⁰³ Other state commissions allow utilities to charge exploration costs to operating expenses.²⁰⁴ In California, on the other hand, costs associated with gas exploration are apportioned under a "50/50" system—half are allocated to the utility's cost of service and half to the stockholders. It is felt that "this system provides an incentive for the utility to select only the most promising ventures, thus prudently controlling costs."²⁰⁵

5. Continuity of Regulation

For a gas utility to raise capital and plan and operate a utility system, it needs continuity of regulatory treatment. Types of costs allowed in one year generally should be allowed to continue through another year. Otherwise, the utility loses the confidence of contractors, investors and others with whom it must deal on a regular basis. In addition, while it is allowed to earn a given rate of return, it cannot achieve such a return if legitimate costs incurred are disallowed in a rate decision.

The average term served by a typical state utility commissioner is short—only 4.42 years compared to 7.25 years in 1968.²⁰⁶ Thus, more rapid changes in commission policy due to personnel changes are becoming an increasing concern.

6. Forward Looking Test Years

Typically in rate cases, a cost of service must be determined for an annual period.²⁰⁷ Usually this is the most recent preceding 12 month period for which data is available. This is called the base period. When certain adjustments are made to the base period (to reflect anomalies and subsequent developments) the result is a "test year." Using this test year, an estimated "cost of service" is developed to reflect anticipated sales revenues, operating and depreciation expenses, taxes and a fair return on plant and equipment (rate base).

In inflationary times, basing revenue requirements on historic costs means that the utility will not recover its actual costs. Thus, a forward looking test year or some other system by which anticipated costs are projected is essential to a utility's revenue needs. Only 13 states currently use forecast test years and many of those are only partial forecast test years.²⁰⁸

²⁰³Chase and Cycon, *supra* note 195, at 18; Kansas Nebraska Natural Gas Co., 100 PUR 3d 129, 135 (Wyo. 1973).

²⁰⁴*See, e.g.,* Re Mountain Fuel Supply Co., 23 PUR 4th 346 (Utah 1977); *but cf.* Re Tampa Electric Co., Docket No. 73604-EV, Order No. 6131 (May 2, 1974), where the Florida commission disallowed coal exploration expenses to an electric utility. Michigan also allows drilling expenses as operating expenses. Michigan Consolidated Gas Co., 78 PUR 3rd 321 (1968). Cited in Chase and Cycon, *supra* note 195, at 19, n. 53.

²⁰⁵*Id.* Chase and Cycon, *supra* note 195, at 19; Southern California Gas Co., 100 PUR 3d 401 (1973).

²⁰⁶NARUC Bulletin 46-80, at 17 (Nov. 17, 1980).

²⁰⁷FERC, Filing of Initial Rate Schedules, 18 C.F.R. 35.12 (1980), and Filing of Changes in Rate Schedules, 18 C.F.R. 35.13 (1980).

²⁰⁸National Association of Regulatory Utility Commissioners, 1979 Annual Report on Utility and Carrier Regulation, at 405 (1980).

Long delays in rate cases or delaying the effective date of a rate increase (such as by an automatic 6 month suspension) also can prevent the utility from earning its authorized rate of return and should be discouraged. As one utility executive has stated, "The easiest way for a regulatory agency to deny rate relief without appearing to do so is to condone, even encourage, regulatory lag."²⁰⁹

7. Inadequate Depreciation Allowances

Depreciation is an important factor in gas utility company earnings. In 1979, for example, depreciation expenses for gas transmission and distribution companies totalled \$2.3 billion compared with \$2.1 billion of interest on debt and \$3.9 billion of net income on equity.²¹⁰ Accrued depreciation in 1979 for transmission companies totalled \$13.3 billion or 48% of gross plant, while for distribution companies accrued depreciation totalled \$11 billion or 31% of gross plant.²¹¹

Because of the long physical life (20 or more years) of most utility company plant and the rate of inflation, currently allowed depreciation rates generally fail to provide enough capital to permit the company to replace existing plant. Indeed:

- Typically, the investment is recovered at only original cost and after many years.
- Frequently, the capital required for replacement of existing facilities is many times the depreciation reserve accumulated on the retired plant item.
- Because the lives of debt securities are being reduced substantially in order to be marketable, there is insufficient cash flow from depreciation to meet reasonable sinking fund requirements of debt securities.²¹²
- Even if adequate depreciation is allowed for tax purposes its benefits sometimes have been required to be flowed through to rate payers rather than retained by the gas company.

It is difficult to solve these problems under established depreciation policies.²¹³ However, their impact can be ameliorated by accelerated depreciation provided that such accelerated depreciation is recognized in the cost of service upon which rates are based. That means that depreciation for both book and rate purposes would be synchronized. Any higher depreciation or amortization charges would create a reserve which becomes a credit to the rate base and, therefore will lower future levels of return below those otherwise required.²¹⁴ It is likely that further measures will be needed to reduce the impact of inflation on capital recovery. One option to be considered is an accounting method by which depreciation expense accruals will recognize current value or replacement costs rather than original costs.²¹⁵

²⁰⁹Seder Address, *supra* note 177.

²¹⁰Davis, in Chapter on *Depreciation* in Regulation of the Gas Industry (1981).

²¹¹*Id.*

²¹²*Id.* The Accelerated Cost Recovery System, to be implemented by the Economic Recovery Tax Act of 1981, will alleviate this problem to some extent. See 26 U.S.C. § 168 (1981).

²¹³*Id.* The Economic Recovery Tax Act of 1981 makes the normalization method of accounting mandatory for public utilities that use the accelerated cost recovery system is a step in the right direction. 26 U.S.C. 168(e)(1981).

²¹⁴*Id.*

²¹⁵*Id.*

Changes in depreciation methods for gas distribution companies are complicated by the fact that individual depreciation rates are established at the state level in each state (except for states such as Nebraska and Texas, where municipal bodies regulate gas utilities). In 16 states the depreciation rates are established pursuant to statute while in others they are under the utility commission's general regulatory authority.²¹⁶ Thus, changing depreciation policies will require not only state by state regulatory changes but in some instances, legislative and even city by city changes.

8. Taxes and Other Financial Hurdles

There are other financial hurdles to capital generation. For instance, taxes as a component of the national average price of gas to consumers rose from 15 cents per Mcf in 1973 to 54 cents per Mcf in 1979—a 260% increase in six years.²¹⁷ Thus, some offsetting tax relief for utilities should be considered.

One possibility would be to modify or eliminate taxation of corporate dividends at the shareholder level. Currently, corporate cash and property dividends are taxed twice. First, they are taxed as corporate earnings and second, shareholders must pay taxes on dividends received.²¹⁸ As one tax expert has noted, this discourages savings and necessary investment in utilities, which are capital intensive industries, in a number of ways:

First, it encourages an over-reliance on debt financing as opposed to equity financing. Second, it weakens the company's capital structure by raising the debt-equity ratio and reducing the interest coverage ratio (the ratio of a utility's earnings to its interest on debt). These two ratios are critical to the bond rating which the company receives from the bond rating services. Consequently, the utility's bond rating is lower and its debt instruments must yield higher interest rates resulting in increased capital costs to both the company and its ratepayers. These higher interest rates must ultimately be borne by the ratepayer. Finally, current tax policy raises the cost of equity capital. The over-reliance on debt financing increases the financial risks assumed by the equity investor, thus lowering the price he is willing to pay for common stock.²¹⁹

Other tax provisions also should be examined to provide incentives to gas utilities to finance energy facilities. For instance, the investment tax credit,²²⁰ which provides a credit against taxes due for qualified investment in certain utility property, should be increased from 10% to 12% and made permanent as a further encouragement to utility company capital formation.²²¹ It also should not flow through to ratepayers.

In addition, a current tax deduction should be considered for feasibility and environmental studies, certification, start-up programs, and pre-operating expenses (including training costs) related to the development of new domestic energy

²¹⁶*Id.*

²¹⁷American Gas Association, *Energy Analysis: Impact of Rising Taxes on Natural Gas Prices Since 1973*, 1980-16, at 1, 2 (December 31, 1980).

²¹⁸Testimony of John J. Curtis, *supra* note 175, at 6.

²¹⁹*Id.* at 7.

²²⁰I.R.C. § 46(c)(3)(f) (1980).

²²¹Testimony of John J. Curtis, *supra* note 175, at 11; *see also* 26 U.S.C. § 321 (1981), which will provide tax exempt status for stock dividends received in connection with public utility reinvestment programs.

facilities. Under current law, such pre-operating expenses often are treated by the IRS as an integral part of the energy facility, to be capitalized over the life of the plant.²²² Such capitalization yields slower recovery of these costs than if they were made currently deductible.

D. End Use Marketing Restraints and Their Effect on New Gas Supplies

1. The Husbanding Fallacy

Even if the advantages of gas are recognized by the public and policy makers, legal requirements are modified and gas utilities generate more capital, new gas supplies will not be developed unless they can be sold. Thus, end use restraints on gas sales which unduly limit gas markets, should be eliminated.

The relationship between gas supplies and the demand for gas is an area of continuing policy disagreement. The gas industry believes that there is a strong relationship between gas supply and demand—gas supplies will be developed only if producers can identify a market for their gas. On the other hand, many government officials, both in Congress and the Executive Branch, have followed the “husbanding” theory of gas supply: “There is a finite quantity of gas in the ground and if you don’t use it today more will be available tomorrow.”²²³ Charles Curtis, former Chairman of the FERC, recognized the risks associated with the “husbanding theory” when he stated:

²²²*Id.* Testimony of John J. Curtis, at 10.

²²³Lawrence Address, *supra* note 11. The price elasticity of gas supply and reserves has long been a controversial subject. Thus, a brief retrospective view may be useful. The gas industry enjoyed rapid growth from immediately after World War II through the 1960s. This period saw the laying of massive interstate pipelines bringing comparatively low cost natural gas from the gas producing regions of the country, particularly in the South and Southwest, to major urban areas. New markets led to increased gas production. Proved gas reserves increased each year from 1947 through 1967 when reserves reached 292.2 trillion cubic feet (Tcf). American Petroleum Institute, American Gas Association and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1979*, 222 (June 1980) [hereinafter cited as *Reserves*], cited in *Gas Supply*, *supra* note 7, at 17.

Gas sales enjoyed a similar rise. From 1955 to 1967 the volume of sales to commercial and residential gas customers rose from 2.8 Tcf to 5.9 Tcf and from 3.5 Tcf to 7.0 Tcf for industrial customers. American Gas Association, *Gas Facts 1979*, *supra* note 26, Chart 14 (1979). Toward the end of the 1960s, however, the gas supply picture changed dramatically. In 1968, annual gas production exceeded annual reserve additions for the first time in over 20 years. Proved reserves peaked at 292.2 Tcf and have declined each year since, except for 1970 when the massive Prudhoe Bay, Alaska field reserves of 26.0 Tcf were added. *Gas Supply*, *supra* note 7, at 8. From 1967 to 1979 proved reserves declined some 30% to 195 Tcf. *Reserves*, *supra*. This steady decline in reserves was caused primarily by the Federal Power Commission’s regulation of well-head prices of gas sold in interstate commerce at levels which proved inadequate to encourage sufficient new drilling in deeper horizons and new frontier areas. As available gas supply declined, interstate pipelines curtailed their supplies to distribution companies and direct sale customers. For a discussion of this, see Adair and Bloom, *The Emerging Federal Role in Gas Distribution and End Use Regulation* 11, 1 *Energy L.J.* 1 (1980). Customers and distribution companies responded by developing their own supplies and in some cases by filing suit against pipelines in curtailment cases. But by 1977, interstate pipelines were encountering crisis-level supply shortfalls. Total supply was 25% below total interstate pipelines’ demand and individual pipelines experienced even more serious problems. Curtailment levels on some systems reached over 40%. *North Carolina v. FERC*, 584 F.2d 1003, 1008 (D.C. Cir. 1978).

The winter of 1976-1977, the coldest in 100 years in many regions, focused nationwide attention on the gas deliverability problem as hundreds of schools, businesses and factories were closed. Foreign oil imports meanwhile, replaced gas in many cases and rose from 6.13 million bbls day in 1970 to 8.62 million bbls day in 1977. Energy Information Agency, U. S. Department of Energy, *Monthly Energy Review*, (Dec. 8, 1980). These developments made more obvious the need for a comprehensive national energy plan. The Carter Administration developed and sent such a plan to Congress (Presidential Message, *supra* note 54) in April, 1977. This plan in turn led to the enactment in November 1977 of the National Energy Act of 1978 (NEA); see note 56, *supra*, for further description.

Policies can sometimes be self-fulfilling. It would be sad irony if demand policies designed to accommodate declining gas production serve instead to contribute to that decline. The result would be a balanced gas market, but a gas market whose diminished role within the national energy market comes at the expense of greater oil imports.²²⁴

President-Elect Reagan's Energy Policy Task Force report noted this problem too:

In this land of energy plenty, why have we fallen with the energy poor, rather than prospering with the energy rich . . . Much has been done. But what has been done is to impede production and curtail consumption. The government has acted on the principle that the way to deal with energy is to do away with it. Instead of unleashing the resources of a wealthy nation, we have, in the name of saving energy for some unspecified future time, tucked energy away like a rare bottle of wine.²²⁵

The husbanding fallacy has had its impact. Of the 17 industrialized gas consuming nations in the Organization for Economic Cooperation and Development (OECD), only the United States has decreased its gas consumption from 1974-1978. European nations in which gas consumption already was high, generally increased their gas usage between 20 and 40% over the same period.²²⁶ This increased gas use (along with use of coal and nuclear energy) has helped to reduce oil imports. Unfortunately, in the United States, rigidly uniform federal marketing restrictions have resulted in serious problems for local utilities.²²⁷

2. Specific Marketing Restraints

Currently, there are two primary Federal marketing restraints on the industrial sale of gas: the incremental pricing provisions of the NGPA and certain provisions²²⁸ of the FUA. Marginal cost pricing (MCP) currently is more of a threat than a restraint.

(a) Marginal Cost Pricing

Section 306²²⁹ of PURPA requires[d] the Secretary of Energy to study and report to the Congress on gas rate design by May 9, 1980. In its May 9 report, entitled, "Natural Gas Rate Design Study,"²³⁰ the DOE supported marginal cost pricing. This is a rate design concept under which gas supplies are priced "at the margin," that is, at the true economic cost of an additional or marginal unit. The DOE's report suggested that such an approach (rather than traditional accounting cost-based methods in which the higher cost for new gas supplies are "rolled-in" with lower cost supplies) best promotes the three purposes of PURPA: (1) end use conservation (promoted by higher gas costs); (2) efficient use of utility resources (promoted because "the utility will be encouraged to make sensible decisions of its

²²⁴Address of Charles Curtis, Chairman, FERC, before the Annual Meeting of the Interstate Natural Gas Association of America, Palm Beach, Fla. (October 6, 1980).

²²⁵Report of the Energy Policy Task Force of President Elect Ronald W. Reagan, at 1 (Nov. 5, 1980).

²²⁶Gas Supply, *supra* note 7.

²²⁷For a discussion of expanding Federal end-use control see Adair and Bloom, *supra* note 223.

²²⁸Discussed in subpart c, *infra*.

²²⁹15 U.S.C. § 3206 (Supp. II 1978).

²³⁰United States Department of Energy, Natural Gas Rate Design Study (May 9, 1980).

own regarding the need for supplemental gas supplies and expensive imports”);²³¹ and (3) equitable rates (promoted because utilities will “charge all customer classes on the basis of the national consequences of customer usage decisions”).²³²

Viewed from the gas utility perspective, however, there are several fundamental problems with marginal cost pricing:

- (1) First, marginal cost pricing is unnecessary. Gas customers already are receiving adequate price signals to conserve under existing rate design methods.
- (2) As with incremental pricing (discussed *infra*), marginal cost pricing tends to link gas prices to an independent high cost variable—imported OPEC oil prices. Thus, the moderating price damper of lower priced, flowing old gas supplies would be lessened.
- (3) Recent DOE regulatory approaches to natural gas pricing (including marginal cost pricing, incremental pricing and FUA) have not adequately considered a key national concern—how to maintain a growing economy, create necessary jobs, fill other domestic needs and compete with aggressive foreign business. To do this, energy costs to the industrial sector cannot be excessive and gas costs should not attempt to compete with artificially high, unregulated OPEC oil prices.
- (4) DOE has failed to recognize that marginal cost pricing would increase the nation's dependence on foreign oil. This is so because marginal cost pricing will result in: (a) a decrease in the development of higher cost domestic synthetic fuels because their price could not be rolled in with lower cost supplies; (b) a decrease in exploration and development of conventional natural gas supplies because, unless prices are rolled in, new gas may be more expensive at the margin than the *average* price of oil or coal which would not be subject to marginal cost pricing; and (c) an increase in fuel switching from natural gas which would raise fixed costs charged to gas users (for instance, reduced industrial gas load may trigger take-or-pay-for contract provisions, increasing costs to customers); this fuel switching (admittedly anticipated by DOE to take place under marginal cost-based rates) will be composed partially of conversions to imported oil.²³³
- (5) Finally, policy makers have not yet disclosed how marginal cost pricing would be administered.

Thus, marginal cost pricing should not be implemented until satisfactory answers to these questions are proposed and reviewed by affected parties.

²³¹*Id.* at 5-1, 5-2.

²³²*Id.* For a discussion of marginal cost pricing, see Anderson, *The Problems of Marginal Cost Pricing and Its Progeny*, 102 PUB. UTIL. FORT. 7 (Oct. 12, 1978). For a discussion of how theoretical marginalist principles create difficulties, see Lipse and Lancaster, *The General Theory of the Second Best*, 24 Review of Economic Studies 11-32 (1956); for a discussion of charging the marginal customer a marginal rate for use above a lower cost base use, see Cicchetti and Wiener, *The End-User Pricing of Natural Gas*, 101 Pub. Util. Fort. 11 (Mar. 16, 1978).

²³³Natural Gas Rate Design Study, *supra* note 230, Appendix C.

(b) Incremental Pricing

Title II²³⁴ of the NGPA mandates a new gas rate design method called "incremental pricing." This incremental pricing is fundamentally different from an earlier type of incremental pricing in which the costs for new gas supplies were not averaged or rolled in with other gas costs, but were charged to the particular users of the newly acquired gas, such as in *Montana Power Co.*²³⁵

Under Title II incremental pricing, the FERC was required to establish by rulemaking a procedure under which certain industrial interstate gas customers receive the brunt of higher gas prices resulting from Title I of the NGPA. Industrial users²³⁶ (primarily boiler fuel users and industrial facilities) subsidize lower rates for "high priority"²³⁷ users (residential, commercial, school, hospital and low volume users). The price paid by industrial users is based on the price of a competitive fuel, currently high-sulphur No. 6 fuel oil.²³⁸

Incremental pricing was expected to serve two primary purposes. First, it was believed to be politically necessary to shield residential gas users from higher gas costs. Otherwise, some thought the Congress would not enact the phased gas deregulation provisions of Title I. Thus, it is a type of social income distribution plan, protecting one class of users at the expense of another. Second, it was designed to serve as a "market ordering" device. It was believed that industrial users (who are highly fuel price sensitive), when faced with higher gas prices than other users, would pressure pipelines and producers to reduce prices on deregulated gas. Proponents were concerned that if prices for higher cost deregulated gas could be "rolled in" to lower cost flowing gas, interstate pipelines with more older gas to roll in would engage in bidding wars with intrastate buyers for new gas, thus driving prices too high.

There are a number of problems with incremental pricing. First, there is its high cost to the economy and consumers. One study suggests that the inflationary impact of Title II may result in a national annual inflation rate during the 1980s

²³⁴*Supra* note 4.

²³⁵*Montana Power Co.*, 11 FPC 1 (1952).

²³⁶124 Cong. Rec. H.13115 (daily ed. Oct. 4, 1978) (remarks of Rep. Dingell). "Industrial users" are defined in 15 U.S.C. § 3341(c) (Supp. II 1978) as follows: Definitions.—For purposes of this section:

(1) Industrial boiler fuel facility.—The term "industrial boiler fuel facility" means any industrial facility, as defined by the Commission, [FERC] which uses natural gas as a boiler fuel and which is not exempt under section 3346 of this title.

(2) Boiler Fuel Use.—The term "boiler fuel use" means the use of any fuel for the generation of steam or electricity.

FERC regulations further define industrial facilities as "any facility engaged in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product." Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978, FERC Order No. 49, Doc. No. RM79-14 (Sept. 28, 1979) 18 C.F.R. § 282.103(d) (1980). Electric utilities using natural gas as a boiler fuel in generating electricity specifically are excluded from incremental pricing, 15 U.S.C. § 3346(c)(2) (Supp. II 1978), as are certain agricultural users, 15 U.S.C. § 3346(b) (Supp. II 1978). FERC implements incremental pricing through its Phase I rule, 18 C.F.R. § 282 (1979), required under § 3341. The Phase II rule to extend incremental pricing beyond large industrial boiler fuel users, 45 Fed. Reg. 31622 (1980), was rejected by the House of Representatives by a vote of 369-34, H. Res. 655, 126 Cong. Rec. H3855 (daily ed. May 20, 1980).

²³⁷15 U.S.C. 3346 (Supp. II 1978).

²³⁸FERC Order No. 51, 44 Fed. Reg. 57778-89 (1979).

of up to 1.5% higher than without incremental pricing.²³⁹ In addition, a \$55 billion (in 1978 dollars) lower GNP and 1% higher unemployment (1.3 million jobs lost) is forecast to result from incremental pricing.²⁴⁰ This extra inflation results because industrial gas users are more likely to pass through increased gas costs than other users. Thus, a multiplier effect takes place adding more inflation than if all users shared increased gas costs. While some gas customers would save on their gas bills with incremental pricing, these savings would be more than offset by higher overall inflation. And non-gas residential customers receive no offsetting benefits.

Second, while it was hoped that industrial users would help keep gas prices lower under incremental pricing, there is no evidence this has occurred, and the Department of Energy has suggested that incremental pricing has failed as a market ordering mechanism.²⁴¹ There are signs, however, that industrial users concerned over rising gas prices have converted to foreign oil. This is inconsistent with the energy independence goals of the National Energy Act.²⁴²

Third, there have been a number of problems in administering incremental pricing.²⁴³ The basic problem has been how to prevent fuel switching from gas to oil by industrial customers. The Congressional conferees recognized this problem when they stated:

The Conferees urge the Commission to take whatever action it deems appropriate or necessary . . . to avoid any delays in reducing the substitute fuel level so as to avoid the likelihood of conversions from natural gas by industrial users if those conversions would result in increases in natural gas rates for any residential, small commercial and other high priority customers.²⁴⁴

²³⁹It is important to note that this study analyzed the impact of a full Phase II incremental pricing scheme extending incremental pricing to more users than is currently authorized. See note 236, *supra*, re rejection of Phase II incremental pricing. Wharton Econometric Forecasting Associates, Inc. (prepared for the American Gas Association). National Economic Impacts of NGPA Incremental Pricing: 1980 Update (Feb. 1980). See *A New Wharton Study May Prove That Dropping Title II Would Benefit Residents*, Inside Ferc II (Dec. 24, 1979).

²⁴⁰National Economic Impacts of NGPA Incremental Pricing: 1980 Update, *supra* note 239; but see Loury, An Analysis of The Efficiency and Inflationary Impact of the Decontrol of Natural Gas Prices (Apr. 1981) (study funded by the Natural Gas Supply Association).

²⁴¹See Adair and Bloom, *supra* note 223, at 67, citing Inside Ferc I (Feb. 18, 1980) and Inside Ferc 4, 5 (March 3, 1980). Congressman John D. Dingell, a proponent of incremental pricing, has stated that the Congress or FERC should consider some of the following alternatives if the market ordering mechanisms of incremental pricing fail to send adequate pricing signals to producers: provide a market kickout provision for distributors in pipeline service agreements; make pipelines common carriers, *i.e.*, distributors would negotiate directly with producers; make pipeline customers third party beneficiaries in pipeline-producer contracts; implement marginal cost pricing at the pipeline level; establish an incentive rate of return for pipelines tied to purchased gas costs; eliminate minimum bill requirements in pipeline-distributor contracts and take-or-pay provisions in pipeline-producer contracts; outlaw indefinite price escalator provisions such as those which peg well-head prices to oil prices; and sell gas to the highest bidder. Address of John D. Dingell Before the Federal Energy Bar Association, Wash., D. C. (Jan. 29, 1981). For further discussion of some of these proposals, see Tiano, "Market Ordering" Devices from a Gas Distributor's Viewpoint, 107 Pub. Util. Fort. 22 (Mar. 26, 1981); and Fleming and Oliver, Jr., *The Gas Distributor Approaches Deregulation*, 108 Pub. Util. Fort. 13 (July 2, 1981).

²⁴²*E.g.*, 15 U.S.C. § 8301 (Supp. II 1978); see discussion *infra*, at section C re: Powerplant and Industrial Fuel Use Act of 1978 (FUA).

²⁴³Testimony of George H. Lawrence, President of the American Gas Association before the Subcommittee on Energy Regulation of the Senate Committee on Energy and Natural Resources (April 24, 1981).

²⁴⁴H.R. Rep. No. 95-1752, 95th Cong., 2nd Sess. 100 (1978).

As Congressman Dingell, a leading proponent of incremental pricing has noted, such conversions are contrary to the purposes of incremental pricing:

The [NGPA] will not drive industrial gas users off natural gas and onto other fuels. Such a result would be contrary to the very purpose of the bill's provisions . . . If incremental pricing in fact drove industrial users to other fuels, the leverage these users would have with pipeline managements would be lost and the consumer protection aspects of incremental pricing would be seriously impaired. The conferees have provided several statutory guarantees against such an unintended result.²⁴⁵

Such fuel switching cannot be prevented under the current regulatory scheme, however, unless the FERC can track all local markets for gas and oil and react fast enough to prevent the cost of gas in each market from exceeding the cost of oil. It appears, however, that there are too many different local market conditions to track accurately such costs. The FERC has modified its alternate fuel data gathering methodology several times but the problem remains unsolved.²⁴⁶

Fourth, as commentators²⁴⁷ have pointed out, Title II provides a fundamentally new rate design methodology with some unsettling characteristics. Public utility ratemaking generally has been cost based.²⁴⁸ Title II, however, "allocates a 'cost' to industrial customers based on another commodity, the ever increasing cost of OPEC priced fuel oil. Thus, the subsidy to the residential market bears little relation to the true cost of natural gas consumed by those individuals."²⁴⁹ This results in "camouflaging" the true higher cost of gas to residential, high priority users, and other sheltered users contrary to national conservation goals.²⁵⁰

Finally, incremental pricing creates severe planning, operational, and financial problems for gas utilities. For example, when gas utilities lose industrial load, their customer growth patterns shift to more residential or commercial users whose load is primarily space heating and therefore more seasonal. Higher winter peak load demands require increased gas storage or peak shaving capability. This in turn costs all system users more money. On the other hand, if new residential or commercial load is not added to offset loss of industrial load, each remaining customer must pay a greater share of the fixed costs of the distribution system.

In sum, even if incremental pricing could be made to work efficiently, many believe it would result in greater harm than good to national energy and economic goals. Thus, Congress should repeal it.

²⁴⁵124 Cong. Rec. H 13114 (daily ed. Oct. 14, 1978) (remarks of Rep. Dingell).

²⁴⁶See, e.g., Regulations Implementing Alternate Fuel Price Ceilings for Incremental Pricing Under the Natural Gas Policy Act of 1978 (FERC Notice of Inquiry), 45 Fed. Reg. 74505 (1980); Alternative Fuel Price Ceilings for Incremental Pricing Under the Natural Gas Policy Act of 1978 (Interim Rule), 46 Fed. Reg. 15498 (1981).

²⁴⁷Mogel and Mapes, *Assessment of Incremental Pricing Under the Natural Gas Policy Act*, 29 Cath U. L. Rev. 763, at 794 *et seq.*

²⁴⁸*Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n*, 262 U.S. 276, 291 (1923) (Brandeis, J., dissenting).

²⁴⁹Mogel and Mapes, *supra* note 247, at 796.

²⁵⁰*Id.*

c. Powerplant and Industrial Fuel Use Act of 1978 (FUA)

Another Federal marketing restraint on industrial gas sales is FUA. FUA was designed to help achieve energy independence by increasing the use of coal and other alternative fuels as primary energy sources for electric generating plants and major fuel burning installations ("MFBIs," which include large industrial boilers, cogeneration equipment, internal combustion engines and turbines);²⁵¹ reducing oil imports; conserving natural gas and petroleum for essential agricultural uses; encouraging the modernization or replacement of existing and new electric powerplants and MFBIs which cannot use alternate fuels; and upgrading railroad service for coal transport.²⁵²

In contrast with prior law (the Energy Supply and Environmental Coordination Act of 1974, ESECA²⁵³), which allowed such industrial facilities to burn natural gas and petroleum unless affirmatively prohibited by order, FUA automatically prohibits many uses of gas unless such uses are specifically exempted by the DOE.

Under FUA, powerplants and MFBIs are divided into three categories, "existing" facilities²⁵⁴ (those not presumed new by the Act or DOE regulations), "new" facilities²⁵⁵ (those concerning which construction or acquisition occurred after November 9, 1978); and "transitional" facilities (an administratively created category for those not operational on April 20, 1977, the date of President Carter's message to Congress on the National Energy Act,²⁵⁶ but for which a contract for construction or acquisition was signed before November 9, 1978²⁵⁷).

Sections 201²⁵⁸ and 202²⁵⁹ of FUA automatically bar natural gas or petroleum as a primary energy source in *new* electric powerplants and *new* MFBIs unless there is a formal exemption by the DOE. Formerly, section 301(a) of FUA prohibited gas as a primary energy source in *existing* powerplants after January 1, 1990, and banned gas use before 1990 unless it was used by a powerplant as its primary fuel in 1977.²⁶⁰ If gas was used in 1977, the current level of gas use was not allowed to exceed either (1) the average used from 1974—1976; or (2) if it commenced operations after January 1, 1974, its average yearly proportional use during the first two calendar years of operation.²⁶¹ However, these provisions have since been repealed by section 1021²⁶² of the Omnibus Budget Reconciliation Act of 1981 (OBRA).

²⁵¹A major fuel burning installation (MFI) is a stationary unit consisting of a boiler, gas turbine unit, combined cycle unit and internal combustion engine which has a design capability of 100 million Btus per hour or greater, or two or more units on the same site which have a design capability of 250 million Btus per hour in the aggregate. FUA § 103(a)(10), 42 U.S.C. § 8302(a)(10) (Supp. II 1978).

²⁵²42 U.S.C. § 8301 (b) (Supp. II 1978).

²⁵³15 U.S.C. § 791 (1976).

²⁵⁴"Existing electric powerplant" means any electric power plant other than a new electric powerplant." 42 U.S.C. § 8302(9) (Supp. II 1978) and "'existing major fuel-burning installation' means any installation which is not a new major fuel-burning installation." 42 U.S.C. § 8302(a)(12)(A) (Supp. II 1978).

²⁵⁵"New electric powerplant" is defined at 42 U.S.C. § 8302(a)(8) (Supp. II 1978) and "new major fuel-burning installation" is defined at § 8302(a)(11) (Supp. II 1978).

²⁵⁶*Supra* note 56.

²⁵⁷42 U.S.C. § 8302(a)(13) (Supp. II 1978). "Transitional facility" is defined in 10 C.F.R. 515 (1980).

²⁵⁸42 U.S.C. § 8311 (Supp. II 1978).

²⁵⁹*Id.* § 8312 (Supp. II 1978).

²⁶⁰42 U.S.C. § 8341(a) (Supp. II 1978).

²⁶¹*Id.* § 8341(a)(3) (Supp. II 1978).

²⁶²Omnibus Budget Reconciliation Act of 1981, Pub. L. No. 97-35, § 1021, 95 Stat. 357 (1981).

In addition, Section 302(a)²⁶³ allows the Secretary of Energy to prohibit gas (or petroleum) as a primary energy source in any *existing* MFBI if it is determined that the facility:

- (1) has or previously had the technical capability to use coal or another alternate fuel as a primary energy source;
- (2) has the technical capability to use coal or another alternate fuel as a primary energy source, or it could have such capability without—
 - (a) substantial physical modification of the unit, or
 - (b) substantial reduction in the rated capacity of the unit, and
- (3) it is financially feasible to use coal or another alternate fuel as a primary energy source in such installation.²⁶⁴

The original version of FUA section 301(b)²⁶⁵ established identical provisions with respect to existing powerplants. However, section 1021 of OBRA has substituted a new FUA section 301(a) which generally permits the issuance of mandatory prohibition orders only where an existing powerplant voluntarily certifies its “coal capability.” In effect, only existing powerplants which “volunteer” for mandatory prohibition orders are subject to them under FUA although some existing powerplants remain subject to mandatory prohibition orders under the ESECA.

While FUA's goal of energy independence is appropriate, there are many problems with its implementation. First, FUA inadvertently restricts a limited amount of additional gas use which could help achieve such energy independence. For example, the “select use” of more gas in industrial facilities could allow more domestic coal to be burned in areas where air pollution is a potential problem, particularly in the summer months. The use of about 1 Tcf more gas annually, during air pollution peak periods, could enable U.S. industry and electric utilities to burn an estimated 190 million more tons of coal per year—nearly a 30% increase in U.S. coal use—in full compliance with the Clean Air Act.²⁶⁶

Although some sections of FUA (*e.g.*, Section 311(a)(3))²⁶⁷ provide that the Secretary shall grant an exemption where its provisions violate “applicable environmental requirements,”²⁶⁸ it is not clear that such select use of gas for increased coal burning would qualify for an exemption.

Second, there have been other problems regarding both temporary and permanent exemptions. For instance, Section 311²⁶⁹ provides temporary exemptions for powerplants and MBFIs for up to 5 years (with some exceptions) for such reasons as lack of alternate fuel supplies, site limitations, environmental require-

²⁶³42 U.S.C. § 8342 (a) (Supp. II 1978).

²⁶⁴*Id.*

²⁶⁵42 U.S.C. § 8241 (b)(Supp. II 1978).

²⁶⁶The Clean Air Act is found at 42 U.S.C. §7401-7642 (1977). Schlesinger, *Natural Gas Can Help Coal Burn Cleaner*, 14 Environmental Science and Technology 1067 (1980).

²⁶⁷42 U.S.C. § 8351 (a)(3)(Supp. II 1978).

²⁶⁸*Id.*

²⁶⁹42 U.S.C. § 8351 (Supp. II 1978).

ments and public interest considerations. Sections 212²⁷⁰ and 312²⁷¹ provide permanent exemptions for some of these reasons and others.²⁷² Prior to the 1981 repeal of FUA section 301(a), numerous temporary public interest exemptions were granted (under FUA Section 311(e)²⁷³) for the continued or expounded use of gas in existing powerplants. It appears that DOE in granting such exemptions, has recognized that there are sufficient current supplies of gas for such use and that gas can replace significant quantities of imported oil. In 1979, such temporary public interest exemptions allowed industry and gas-fired generating plants to burn the gas equivalent of 300,000 to 400,000 barrels/day of oil. In 1979, gas could have replaced an additional one million barrels/day of oil. By 1985, gas, coal and conservation together, could displace all 5.5 MMbbls./day of oil currently used in stationary boilers.²⁷⁴

While the FUA exemption authority is helpful, temporary exemptions can be rescinded by regulatory action and have a 5-year time limit (with some exceptions). This makes long-range gas use planning difficult. Obtaining an exemption also can be a complex and expensive process. Examples of exemption tests which must be met by petitioners include the requirement that a facility cannot utilize an alternate fuel, such as coal, unless its cost substantially exceeds the cost of imported petroleum;²⁷⁵ that a mixture of an alternate fuel and petroleum or natural gas is not "economically or technically feasible,"²⁷⁶ and that the petitioner must comply with other such conditions as the Secretary determines appropriate, including those "requiring effective fuel conservation measures."²⁷⁷

In the *Anheuser-Busch* case,²⁷⁸ the petitioner was granted a permanent existing MFBI exemption only after agreeing to numerous conservation measures, including modification of all present boiler control systems, the installation of various waste-heat recovery systems, special lights and light timing controls, and a solar energy system for hot water, heating and cooling.²⁷⁹ As one commentator has remarked, "This case suggests that DOE intends to extract all reasonable and possible fuel-conservation measures at a plant site, whether or not such measures apply or relate to the exempt boiler."²⁸⁰

Finally, FUA creates uncertainty in the minds of industrial gas users concerning the continuity of gas supply. Under FUA an existing MFBI can be ordered to switch to an alternate fuel if it has (or had) the technical capability to use an alternate

²⁷⁰ 42 U.S.C. § 8322 (Supp. II 1978).

²⁷¹ 42 U.S.C. §§ 8352.

²⁷² *Id.*

²⁷³ 42 U.S.C. § 8351 (e) (Supp. II 1978).

²⁷⁴ American Gas Association, *Energy Analysis: Survey of Actual and Potential Oil Offsets Enabled by Increased Gas Use in 1980, 1980-6*, at 6 (Apr. 24, 1981); American Gas Association, *Energy Analysis: A Preliminary Evaluation of DOE's Analytical Report Entitled "Reducing U. S. Oil Vulnerability," 1980-15*, at 5 (November 21, 1980).

²⁷⁵ 42 U.S.C. §§ 8321(a)(1), 8322(a)(1)(A) (Supp. II 1978) (new facilities); 42 U.S.C. §§ 8351(a)(1), (Supp. II 1978) (existing facilities).

²⁷⁶ 42 U.S.C. § 8323(a) (new facilities), § 8353(a) (existing facilities).

²⁷⁷ *E.g.*, 42 U.S.C. § 8324(a) (new facilities), § 8354(a) (existing facilities).

²⁷⁸ *Anheuser-Busch, Inc.*, order granting exemptions from the Fuel Use Act, Docket No. ERA-FC-79-001 (DOE) (Dec. 14, 1979).

²⁷⁹ *Id.* slip op., at 8.

²⁸⁰ Lublin and M. Pickholz, *Legislative Note, Introduction to the Powerplant and Industrial Fuel Use Act of 1978: Securing Exemptions for Utilities and Major Industrial Users*, 29 Am. Univ. L. Rev. 485, at 502 (1980).

fuel without substantial physical modification or reduction in capacity, and if such use is economically feasible.²⁸¹ DOE, therefore, can expand or contract the number of existing end users by regulation. Further, the potential sweep of FUA is large. Under Section 401,²⁸² DOE may forbid the use of gas in boilers for steam generated space heating capacity of 300 Mcf/day or more. EIA has estimated that industrial boilers in that category account for some 95% of interstate gas used as boiler fuel.²⁸³ It has been observed:

An end-user must understand the regulations, for their prescriptions now take the place of the economic analysis most end-users previously followed in determining their primary fuel.

Therefore, the end-user is faced with a government determination of which fuels it can use. Furthermore, the government can change the rules as it goes. An end-user which comfortably qualifies for an exemption from fuel switching today may find itself the target of a prohibition order tomorrow. End-users find themselves at the mercies of the vagaries of national energy priorities.²⁸⁴

Thus, for energy security and other reasons, it appears in the public interest to amend FUA provisions which may cause gas marketing uncertainty and prevent a reduction of oil imports, particularly the restrictions on industrial gas use in new (Section 202) and existing (Section 302) major fuel-burning installations, and the current restrictions on the "select use" of gas in conjunction with coal for purposes of environmental compliance.

E. The Need for Regulatory Reform

The gas industry is one of the most extensively regulated industries in the nation. Thus, it has a tremendous stake in regulatory reform—reform that can allow more expeditious development and marketing of gas supplies.

1. The FERC Consistently Has Faced Caseload Management Problems

Since the 1950s the FPC and FERC have had great difficulty coping with their caseload. At one point there was a backlog of approximately 20,000 cases causing years of delay.²⁸⁵

In recognition of this situation, former Chairman Charles Curtis continued and initiated certain reforms. A management control system was instituted to give a monthly up-date of the status of matters. This information system assists the FERC in identifying where delays are occurring with key cases. The FERC has delegated many of its ministerial and minor matters to key staff personnel. This has reduced Commissioner's time on non-essential matters.²⁸⁶

²⁸¹FUA §§ 301(b), 302(a); 42 U.S.C. §§ 8341(b), 8342(a) (Supp. II 1978); it should be noted, however, that the ERA has proposed a rule that would streamline *some*—but not *all*—exemption procedures.

²⁸²42 U.S.C. § 8371 (Supp. II 1978).

²⁸³Energy Information Administration, U. S. Department of Energy Report to Determine 5 Percent Exemption to Incremental Pricing (Feb. 26, 1980).

²⁸⁴Adair and Bloom, *supra* note 223, at 20, 21.

²⁸⁵See Lawrence and Muchow, *The FERC's Case Load Management Problem*, 103 Pub. Util. Fort. 2 (Jan. 18, 1979). Clark, *The Costs and Benefits of Regulation—Who Knows How Great They Really Are?* 48 National Journal, 2023 (Dec. 1, 1970).

²⁸⁶See e.g., FERC order delegating authority to grant exemptions from incremental pricing and amending sections 1.41 and 282.206, Order No. RN80-78 (Sept. 23, 1980).

The FERC has taken steps to encourage the settlement of cases, with a procedure for a "settlement administrative law judge."²⁸⁷ It also has appointed an advisory committee to consider ways of changing its Rules of Practice and Procedure to expedite the decision-making process. This Committee has recommended many changes in procedures which the FERC now has under advisement or in stages of implementation.²⁸⁸

2. Federal Regulatory Reform

A general consensus is emerging that regulatory reform of Federal agency procedures is essential. A number of approaches to reform recently have been suggested or implemented. These include Executive Order 12044²⁸⁹ (1979) by which President Carter attempted to exert control over agency regulatory procedures and the Carter Administration's Regulation Reform Act of 1979,²⁹⁰ which proposed an "omnibus" approach in which across the board changes in issuing proposed rules would be made and applied equally to more than 90 regulatory agencies (this legislation was designed to codify Executive Order 12044). This Act also proposed new agency subpoena authority to encourage parties to comply with agency subpoenas in rule-making proceedings or face severe penalties.²⁹¹

²⁸⁷44 Fed. Reg. 17034 (1981) (to be codified in 18 C.F.R. § 385.603).

²⁸⁸Subcommittee on Hearing Procedures, Federal Energy Regulatory Commission Advisory Committee on Revision of Rules of Practice and Procedure, Part 385, Rules of Practice (Nov. 21, 1980).

²⁸⁹3 C.F.R. § 12661 (1979). This required each executive agency to (1) adopt procedures to increase public participation in the early stages of regulation development; (2) exercise agency head oversight in developing regulations; (3) write regulations in plain English; (4) regulate in the least burdensome way after considering alternative regulatory approaches; and (5) issue a semiannual report of upcoming regulations, a regulatory analysis of significant proposed regulations, and a review of existing regulations. This Executive Order has no force over independent regulatory agencies, however.

²⁹⁰The White House, The Regulatory Reform Program and the Regulation Reform Act of 1979, (RRA) proposed by the Carter Administration at 1 Pub Papers 493 (March 25, 1978). It was assumed in the RRA that all 90 regulatory agencies have similar problems which can be solved by omnibus legislation. This is not the case, however. At the FERC for instance, two problems aggravating the backlog of thousands of cases are: (1) lack of assigned management responsibility for moving specific cases by specific dates; and (2) the necessity for all cases to come before the full commission—all five commissioners. None of the pending regulatory reform proposals would solve either problem. Instead they may make the problem worse by adding new procedural delays. One possible solution would be a specific agency-by-agency review of the reasons for delay, as Professor Ernest Gelhorn has suggested. Gelhorn, *Reform as Totem—A Skeptical View*, 3 AEI J.L. on Government and Society 3, 26 (May/June 1979). Other procedural reforms also are possible.

FERC, for instance, could use an applicant's draft Environmental Impact Statement as the basis for comments from the public and governmental agencies. Instead, FERC prepares it own. This results in unnecessary delay. FERC also could use panels of commissioners in certain cases; it does not currently do so. Finally, FERC could set deadlines for each critical stage of agency action. Currently, it does not. Such delays are not just academic. In January 1981, Robert H. Willis, Chairman and President of Connecticut Natural Gas Corporation, pointed out that FERC delays have led to many gas cases awaiting action. In his company's case, he has been waiting for years to receive FERC approval for a pipeline to carry gas from a storage field in Pennsylvania to his service territory, gas critically needed in the cold winter of 1980-1981. United Press wire story, *Natural Gas*, (Jan. 19, 1981).

²⁹¹Section 203 of the RRA would have allowed self-executing subpoenas. Administrative law judges or other agency staff would have power to:

- prohibit allowing matters into evidence;
- infer that subpoenaed materials are adverse to the party;
- strike pleadings and motions; and even
- dismiss the proceeding

without going to court. Presumably citizens would have to initiate suit (such as by seeking an injunction) to prevent such a result. Giving such powers to hearing offices may be unprecedented in American law. The issuance by an administrative agency of compulsory process is a search and seizure protected by the Fourth Amendment and enforcement should lie with the judiciary to ensure due process. *Oklahoma Press Publishing Co. v. Walling*, 327 U.S. 186, 217 (1946). It is doubtful that FERC's current subpoena authority is inadequate in any event.

Other reform measures include creation of a Regulatory Analysis Review Group to review at the White House level, major agency regulatory proposals,²⁹² a "pro-competitive" standard under which Federal regulations would be required to achieve the intended result in the "least anti-competitive way,"²⁹³ and judicial veto, in which on appeal, a regulatory agency would have the burden of proving by "a preponderance of the evidence shown" that the rule or standard litigated is valid.²⁹⁴

Within 30 days after his inauguration, President Reagan moved to issue Executive Order 12991.²⁹⁵ This Order mandates *inter alia*, that (1) Federal agencies shall not "regulate unless the potential benefits to society for the regulation outweigh the potential costs to society;" (2) regulatory objectives shall be chosen to maximize the net benefits to society; and (3) "among alternative approaches to any given regulatory objective, the alternative involving the least net cost to society shall be chosen." Each agency is required, with every "major rule" (generally one with an impact of over \$100 million or more or with a major increase in costs or prices or other specified adverse effects)²⁹⁶ to prepare a Regulatory Impact Analysis and transmit it with notices of proposed rulemaking and all final rules to the Director of the Office of Management and Budget (OMB) for review. In effect, no major proposed rulemaking is likely to be published in the Federal Register unless approved by OMB. This new approach should help to reduce the number of or at least slow down the issuing of some 7,000 Federal regulations typically promulgated each year.²⁹⁷

There are a few basic federal regulatory problems affecting the gas industry. Chief among these are:

- Delays in the FERC and the ERA in obtaining final agency actions on licensing, certificate and rate matters. These delays occur primarily: (1) after filing an application and before the beginning of the hearing; and

²⁹²This proposal, found in S. 2147, 96th Cong., 2d Sess. (1980) (Culver, Kennedy et al.), would create a Regulatory Policy Board—an arm of the White House—to review certain regulatory actions. Without detailing the steps in the proposal, its approach may shift responsibility for decision-making away from agencies and add another level of White House clearance and delay to energy decisions. The challenge is to keep agency actions expeditious without adding more layers of bureaucratic oversight which breed delay.

²⁹³See e.g., Section 642 of S. 2147, 96th Cong., 2d Sess. (1980), which would preclude an agency from adopting a rule in certain cases unless, "the agency has considered the effects on competition . . . and made a finding that the policy or rule is the *least* anticompetitive alternative legally and practically available to the agency to achieve its statutory goals." (Emphasis added). First, it would be inappropriate to require such a finding for a regulated monopoly. See *Northern Natural Gas Co. et al. v. Federal Power Comm'n*, 399 F.2d 953, 965 (D.C. Cir. 1968); See also *United States v. El Paso Natural Gas Co.*, 376 U.S. 651, 659-660 (1964). Further, competition and antitrust questions already are considered by the FERC in rendering its opinions: *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973). Finally, the requirement of finding the "least anticompetitive alternative" opens the door to years of delay in fact finding and appeals.

²⁹⁴This proposal, e.g., S. 1477, 96th Cong. 2d Sess. (1980), would strike down the presumption in court that a rule or regulation of any agency is valid, and substitute a standard that when an agency rule or standard is challenged in federal or state court, "the court shall not uphold . . . [its validity] unless such validity is established by a preponderance of the evidence shown." The Congress failed to act on this proposal, however.

It would:

- add to judicial delays;
- make it more difficult for rules to be made with timely finality; and require *de novo* trials by courts on complicated regulatory issues that may have taken years to resolve; and
- in effect, create a judicial veto power to override legitimate agency decisions. It reverses the "substantial evidence" and similar rules which have served administrative law well for many years. Neither the Congress nor the courts are the best forums for complex, technical regulatory determinations. *Consolo v. Federal Maritime Comm'n*, 383 U.S. 607 (1966).

²⁹⁵Exec. Order No. 12291, 46 Fed. Reg. 13193 (1981).

²⁹⁶*Id.* at § 1(b). See also H.R. 746, 97th Cong., 1st Sess. (1981).

²⁹⁷The Wash. Post, May 4, 1981, at A1, Col. 4.

(2) from the time of the administrative law judge's initial decision to the time of a final decision by the agency;²⁹⁸

- Court challenges to agency approval for energy projects which delay such projects; and
- Multiple and overlapping federal and state licensing and other regulatory requirements in applications for approvals for new facilities or services.²⁹⁹

Unfortunately, the approach taken by some of the proposed reform legislation listed above does little to solve these problems and may make them worse. Some of these proposals require more review, more data collection, more paperwork, more delay, and potentially greater cost to the consumer.³⁰⁰

It is tempting to layer the federal regulatory problem with whole new programs rather than to examine the structure carefully and correct its faults. Regulatory reform proposals should focus on a few basic regulatory solutions including:

- more careful draftsmanship by legislators of energy agency statutory charters;
- better agency-by-agency oversight by congressional committees to spot and eliminate unreasonable Federal regulatory abuses and delays;³⁰¹
- a net reduction in the number and complexity of regulations governing energy companies; and
- careful regulation by well-managed, accountable, knowledgeable regulators acting under fixed time schedules but with flexible administrative procedures.³⁰²

While these suggestions may help in the near term, they are not sufficient. More valuable would be a comprehensive task force review of the Federal legislative and regulatory scheme frustrating the development of necessary gas and other energy supplies. This could be an early goal of any new Energy Mobilization Board which could provide a "fast track" for important energy projects.³⁰³ In the

²⁹⁸For further details, see Lawrence and Muchow, *supra* note 285, at 9.

²⁹⁹*Id.*

³⁰⁰President Reagan seems to be addressing these problems forcefully however, see Fact Sheet, President Reagan's Initiatives to Reduce Regulatory Burdens, The White House (Feb. 18, 1981); see Address by the President to a Joint session of Congress on a Program for Economic Recovery, The White House (Feb. 18, 1981).

³⁰¹See Lawrence and Muchow, *supra* note 285, at 9.

³⁰²*Id.*

³⁰³E.g., S. 668, 97th Cong., 1st Sess. (1981) (Sen. Jackson), which creates an Energy Mobilization Board with powers to consolidate energy related decision schedules, designate priority energy projects and recommend waiver or suspension of federal, state or local laws; see also H.R. 3236, 97th Cong., 1st Sess. (1981) (Rep. Udall), which creates a three-member Council on Energy Mobilization to designate priority energy projects for expedited licensing by federal, state and local agencies. Unlike S. 668, this legislation does not permit waiver of state or local laws; rather, it permits a 10-year respite from compliance with laws enacted after the start of a priority energy project.

³⁰⁴As Irving Shapiro recently stated when asked what he would do to resolve regulatory overkill: "It seems to me the starting point is to recognize that the administrator and the industry need not be adversaries. They ought to have a common objective. Most businessmen are sensible and rational people. They recognize that they've got to meet the needs of our society or they're not going to be successful. And so I would make the case that if you get rid of the adversary approach and simply say we have a common objective—one as a representative of the public sector—the other as a representative of the private sector—we ought to sit down and talk about how to get from here to there. You very often would wind up with good answers. Once the objectives are agreed on, industry is a lot more resourceful than government could be in finding the routes to get from here to there in the most efficient way." The Wash. Post, Feb. 8, 1981, at G2, col. 1.

case of gas, the NEA, the Public Utility Holding Company Act of 1935 and other legislation regulating the gas industry should be examined with the goal of increasing energy supplies as necessary (*e.g.*, consistent with conservation goals) while protecting the public interest. The Departments of Energy, Interior, Commerce, State and other agencies important to energy policy also should be examined to see what changes can be made in their policies and procedures to reduce delays in energy projects.

CONCLUSION

The United States can have the gas energy needed for the future if government and industry will set a common goal and work to achieve it.³⁰⁴ This goal should be to reduce the attitudinal, legal, financial, marketing and regulatory barriers to the development of gas energy. This goal should receive high priority. Not just because priority attention is essential to eliminating these barriers in a reasonable time frame, but also because this goal appears to be in the nation's best interest.

