THE LONG-TERM OUTLOOK FOR LNG TRADE AND REGULATION IN THE UNITED STATES

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I. Summary

The world has vast resources of gas energy. Current world estimates indicate proven natural gas reserves of over 2,700 trillion cubic feet (Tcf) — excluding potential gas resources. It is estimated that 450 Tcf of proven reserves are in the Western Hemisphere, 195 in Africa, 636 in the Middle East, 180 in Asia and the Far East and 1,100 are in Eastern Europe.[1] While significant amounts of Western Hemisphere gas can be imported by pipeline from Canada and Mexico, most of the world's resources can be made available to major markets only by the transportation of liquefied natural gas (LNG).

The domestic gas supply outlook in the United States has improved dramatically since the passage of the Natural Gas Policy Act of 1978 (NGPA).[2] Because of this and other factors the gas supply-demand balance is not favorable in this decade to LNG imports beyond currently planned or operating projects. However, a long-term view gives reason to believe that the environment for increased LNG imports will improve.

While current excess gas deliverability is likely to exist for several years, the present demand for gas energy should grow as the economy recovers.[3] Further, recent studies indicate that a variety of supplemental gas sources will become increasingly attractive as conventional energy sources: (1) continue to rise in cost; (2) approach their maximum potential, as in the case of hydroelectric power; and (3) are constrained by protracted technical, environmental and political problems, as in the case of nuclear energy and coal.[4]

While there will be difficulties, there are several reasons to believe that future increases in U.S. LNG use can be achieved. First, the United States has in place three major LNG receiving terminals that immediately can handle substantially greater volumes of LNG and efficiently transport it throughout much of the nation at very

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This article represents the views of the authors and not necessarily those of the American Gas Association.

[1] Other reserves are in Western Europe. 80 Oil and Gas Journal 88 (Dec. 27, 1982).

[2] 15 U.S.C. §§ 3301-3432, 42 U.S.C. § 7255 (Supp. II 1978).

[3] American Gas Association, The Gas Energy Demand Outlook: 1981-2000 (1982 Update), 2, [hereinafter cited as Demand Outlook].

[4] American Gas Associaiton, The Gas Energy Supply Outlook 1980-2000 (1982 Update), 36-41, [hereinafter cited as Supply Outlook].

little incremental capital cost.[5] These terminals are, in effect, an underutilized national resource.

Second, LNG continues its favorable safety record acquired in worldwide trade since commercial shipments began in 1964.[6]

Third, and most important, the gradual decontrol of U.S. natural gas wellhead prices is raising the price of domestic gas to levels comparable to residual oil. This requires the U.S. natural gas industry to develop many new marketing and business skills. As part of this process, however, new premium value gas markets are beginning to emerge in which the cleanliness and efficiency of natural gas can be used to maximum advantage. Such a transition can effectively put LNG to work easing this country's environmental problems and switching us away from over-dependence on the world's petroleum resource base.

Increased U.S. LNG imports will require, however: (1) the sale of LNG by exporting nations under terms that ensure long-term prices at marketable levels; (2) continued U.S. progress along the path to market-determined gas prices; (3) development of new technology and marketing initiatives in the natural gas industry; (4) removal of legislated gas marketing constraints and increased regulatory flexibility to permit the U.S. gas industry to develop new gas markets and respond more promptly to market conditions; (5) improvements in the existing U.S. system of overlapping and frequently changing regulations which have delayed past LNG projects; and (6) assurance to investors financing the projects that trade terms, including those that provide market flexibility, will be honored.

II. Background

1. *The Importance of Natural Gas to the U.S.*

Natural gas currently accounts for 27% of all energy consumed in the U.S. and 33% of all energy domestically produced.[7] Gas is the fuel for over half of all U.S. residences and commercial establishments. Industry and agriculture in the U.S. depend more heavily upon natural gas than on any other form of energy. Gas comprises 36% of the energy consumed in these sectors.[8] North American natural gas production and consumption are the highest of any area of the world.[9] Thus, adequate gas supply at reasonable prices has an important impact on the U.S. economy. At the same time, the fact that the U.S. has the world's largest gas infrastructure — a million-mile pipeline and distribution system — and the fact that the system is 15-20% underutilized, means that the U.S. could play a special role in utilizing the world's gas resources with very little incremental capital cost for new facilities.

[5] They are located at Lake Charles, LA, Cove Point, MD and Elba Island, GA. Before supplies were interrupted in 1980, the Cove Point, Maryland and Elba Island, Georgia terminals were utilized to import Algerian LNG under contracts totalling 365 Bcf/year. Although purchases contracted for the Lake Charles, Louisiana terminal total 165 Bcf/year, the Trunkline LNG Company has been negotiating a reduction in purchases made between April 1, 1983 and November 30, 1984 resulting in an annual import rate of 156 Bcf. In addition to these major terminals, there are other terminals which are used only for peak-shaving purposes. For example, Distrigas Corporation maintains a non-baseload terminal in Everett, MA, where it receives Algerian LNG. Boston Gas Company maintains a peak-shaving terminal in Boston, which handles only domestic LNG. American Gas Association, Gas Energy Review 13 (September 1979).

[6] Poten and Partners, Inc., Liquefied Gas Ship Safety (June 1982).

[7] American Gas Association, Demand Outlook, *supra* note 3, at 2.

[8] American Gas Association, Demand Outlook, *supra* note 3, at 7, 13 and 20.

[9] American Gas Association, A Comparison of U.S. and World Remaining Gas and Oil Resources, 4 (December 1982).

2. *U.S. Gas Supply Outlook*

Over the past five yeras, the outlook for gas supply in the United States has improved substantially. After 25 years of controversy over Federal field price controls, the U.S. Congress enacted the Natural Gas Policy Act of 1978 (NGPA), which initiated a gradual transition to deregulated field prices for natural gas. The response has been impressive both in terms of current gas deliverability — resulting in significant excess gas availability relative to gas requirements — and in additions to proven U.S. gas reserves.

Gas well completions in 1981 and 1982 reached new records, although reductions will occur in 1983 due to the lingering effects of economic recession and other market factors including price-induced conservation. U.S. government data show that in 1981, gas reserve additions in the lower-48 states exceeded production for the first time in 14 years. Total U.S. reserve additions of 21.4 trillion cubic feet were 114 percent of production, the highest level since 1967 in the lower 48 states.[10] Thus, indications point to a medium term outlook for lower-48 states' conventional gas and tight formation production near current levels.

While the present gas supply-demand situation may not support new LNG projects not already in the development or operating stages, it is suggested here that the United States should take a longer view of energy policy and energy options.

By the year 2000, conventional lower 48 gas supply may have declined from the current 18-19 Tcf/year range to 12-14 Tcf/Yr. By that time, however, total gas supply still can reach 23-31 Tcf/year, depending upon U.S. long-term gas energy policy. Such gas supply can include: (a) new and increased natural gas production capabilities from such technologies as advanced rock fracturing techniques for Western tight sands and Eastern Devonian shales and gas from renewable resources such as biomass from urban and animal wastes; (b) synthetic gas from coal, peat, oil shale and other heavy hydrocarbons; (c) pipeline supplies from Canada, Mexico and Alaska; and (d) LNG imports.[11]

The consensus of recent major energy studies surveyed annually by the American Gas Association is that U.S. primary energy consumption will rise, in spite of substantial conservation, to 90-99 quadrillion Btus (quads) by the year 2000, from 70.8 quads in 1982. Extensive simulations conducted with the A.G.A. Total Energy Resource Analysis (TERA) model indicate that potential gas supplies will be able to compete successfully with other energy sources on the basis of cost in this future energy market. It should be noted that gas imports as a whole are unlikely ever to exceed 26% of total U.S. gas supplies. The potential role of LNG as a supplemental gas supply source to the U.S., however, is significant, amounting to 0.7 to 2.5 Tcf/yr.[12]

3. *Potential Benefits of LNG Trade*

The potential benefits of increased LNG trade include the following. First, there are in place three major LNG receiving terminals on the East and Gulf Coasts that can accommodate significant new volumes of LNG. Such terminals are connected with major transmission systems that make possible a wide and efficient distribution of LNG in the U.S. at nominal incremental capital cost. A fourth terminal, the Distrigas terminal in Everett, Massachusetts, has been in operation since 1976, and has played an important role in meeting peak winter needs in the

[10] [1981] D.O.E. ANN. REP. U.S. CRUDE OIL, NAT. GAS AND NAT. GAS LIQ. RES. U.S. Dept. of Energy.

[11] Supply Outlook, *supra* note 4, at 2, 3.

[12] Supply Outlook, *supra* note 4, at 3.

New England region. Second, studies indicate that gas energy is the environmentally cleanest and most resource and capital efficient major energy form. LNG captures these attributes.[13] For example, water pollution and solid wastes resulting from the LNG cycle are negligible. NO_x emissions — the major type of air emissions from the LNG cycle — total less than 6% of the NO_x emissions from the coal-electric cycle and 50% of those from the oil cycle when end-use burning is included.[14] Third, in 19 years of extensive worldwide experience with the commercial shipping of LNG, the industry has compiled an outstanding safety record.[15]

Fourth, there is a substantial and underutilized worldwide gas resource base currently estimated at over 2,700 Tcf of proven reserves. In addition to the world's large base of unconventional gas resources, conventional world gas resources are about 75% of world oil resources on an energy equivalency basis. Oil, however, currently is being produced at some 2.2 times the rate of gas.[16] LNG offers a means of utilizing the world gas resource base by bringing gas to the major existing world energy markets where developed gas use infrastructures exist. Consuming nations can benefit by increased LNG consumption and by participation in the design, financing and construction of LNG facilities. Producer nations can benefit by slower depletion of their oil reserves and by revenue gained form what otherwise may be an under-utilized resource.

4. *Major LNG Issues and Problem Areas*

In the mid-1970's, many were projecting that world LNG trade could grow to over 4 Tcf by 1982 with the U.S. playing a major role.[17] Instead, the 1982 level of world LNG trade was just over 1 Tcf annually, with U.S. imports of only 63.6 Bcf (approximately 7% of world LNG trade).[18] Japan and Western Europe respectively account for approximately two-thirds and one-quarter of world LNG imports. With LNG's advantages, why has LNG trade — especially to the U.S. — not lived up to expectations?

a. *Pricing and Marketability* — First, the price of LNG was often and erroneously compared by both regulators and consumers in the U.S. to the artificially low price of Federally regulated domestic gas rather than to the principal energy form which it would displace — foreign oil.[19] This problem was exacerbated by the absence of developed premium (higher) price natural gas markets in the U.S., in contrast to the large transportation sector premium market for oil products,[20] plus the higher costs of shipping and handling LNG as compared to oil.[21] More recently, the economic recession and the gradual decontrol of domestic wellhead gas prices have produced a substantial surplus deliverability of domestic gas and have dampened the outlook for gas demand in conventional gas markets in the short term.

[13] American Gas Association, Fact Book: LNG, E-1 (1977).

[14] American Gas Association, Comparison of Initial Capital Investment Requirements for New Domestic Energy Supplies: 1982 Update, 1, 14 (January 1982).

[15] Danahy and Bruce, "Equivalent Safety and Hazardous Materials Transportation," American Society of Mechanical Engineers Miscellaneous Paper 73-ICT-86 (1973).

[16] Supply Outlook, *supra* note 4, at 5, 7.

[17] *Supra* note 13, at Exhibit K-3.

[18] American Gas Association, Gas Facts 120 (1982); American Gas Association, Quarterly Report of Gas Industry Operations, Third Quarter 1982, 4 (February 1983).

[19] *Supra* note 13, at 10.

[20] *Supra* note 13, at 22.

[21] 14 LNG Digest, at 4 (November 1982).

b. *Legal and Regulatory Delays* — In an era of rising gas costs and short-term excess deliverability, federal and state regulators and legislators have increased their scrutiny of LNG imports.

Recent Federal Regulatory Actions — The Trunkline LNG Company project to import LNG from Algeria provides an example of Federal barriers that must be overcome for LNG trade to reach its full potential. In 1977, the Federal Power Commission (FPC) authorized the importation for 20 years of the equivalent of 165 Bcf per year of LNG by Trunkline LNG Company, a subsidiary of Panhandle Eastern Corporation. The FPC also approved construction of an LNG terminal to receive and regasify the LNG at Lake Charles, Louisiana.[22] Although deliveries were scheduled to begin in 1980, they were delayed when technical and other problems arose between Sonatrach, the Algerian exporter, and Trunkline. A new pricing agreement between the parties was announced in August 1982, clearing the way for imports to begin. The Michigan Public Service Commission and Panhandle's customers and other petitioners then asked the FPC's successor, the Federal Energy Regulatory Commission (FERC) to rule that the new gas pricing agreement constituted a new contract, requiring a new, full examination of the import authorization.[23] They requested that the import license be suspended or revoked on grounds that the gas was not needed, it was too expensive, and that Algeria was an unreliable supplier. Trunkline strongly disagreed. In September 1982, the FERC issued a show cause order requiring Trunkline to show why it would be in the public interest to import Algerian LNG; and the FERC and ERA ordered joint hearings on whether to revoke the project's 1977 authorization order.[24] These hearings, which lasted for 22 days, produced a record of more than 4,000 pages and 200 exhibits.[25]

In January 1983, FERC Chief Administrative Law Judge Curtis Wagner, Jr., ruled on evidence in the *Trunkline* case. He held "There is no evidence in this record of any kind . . ." that trunkline or Sonatrach had breached the 1975 contract or the import authorization by non-performance or refusal to perform. Further, he held, the law requires that . . . absent such a breach ". . . there is absolutely no authority in either this commission or [ERA] to revoke, suspend, or modify . . ." a certificate or authorization.[26] Wagner noted that the reason for the sanctity of certificates is that massive investments must be made to construct facilities. To change these certificates which are the ". . . basis of project financing, would be a clear violation of the basic constitutional principles of due process."[27] Wagner also found that as long as Sonatrach continued to perform under the 1975 contract and any approved amendments there is no reliability issue. He noted that the Algerian supplies will be needed when Panhandle's committed reserves fall short starting in 1984. "The need for the involved 20-year supply of LNG from Algeria cannot be determined on the basis of the current short-term bubble."[28] Finally, LNG is marketable because "it is

[22] Federal Power Commission, Opinion Number 796, April 29, 1977.

[23] *Trunkline LNG Co.*, Federal Energy Regulatory Commission Docket Numbers CP74-138-003, CP74-139-001, CP74-140-001, CP82-517-000, CP82-519-000, CP82-533-000, CP82-541-000, RP82-127-000, January 28, 1983, at 13.

[24] Federal Energy Regulatory Commission, Docket Number CP-138-000, September 24, 1982. Joint Order of the Federal Energy Regulatory Commission and the Economic Regulatory Administration, 82-12-LNG, October 28, 1982.

[25] News Release by the Federal Energy Regulatory Commission, at 1 (Dec. 15, 1982).

[26] *Trunkline LNG Co.*, Recommended Decisoin of Chief Administrative Law Judge Curtis Wagner, Jr., Federal Energy Regulatory Commission Docket Numbers CP74-138-003, CP74-139-001, CP74-140-001, CP82-517-000, CP82-519-000, CP82-533-000, CP82-541-000, RP82-127-000, January 28, 1983, at 13.

[27] *Supra* note 26, at 19.

[28] *Supra* note 26, at 34-36.

rolled in to the large quantities of low-cost, price regulated gas . . . on the Panhandle Trunkline Systems."[29]

In February, 1983, the FERC voted in principle to uphold Judge Wagner's decision but urged Trunkline and Sonatrach to renegotiate a lower price consistent with "current economic conditions." Failure to do so, the Commission said, could "lead to the conclusion that the 1977 certificate should be revoked for failure of the parties to the contract to honor it."[30] The ERA agreed with the FERC that there was insufficient cause to revoke the project's import authorization. ERA emphasized, however, that it intended "to review this existing authorization at any time in the future and make any change or modifications, including revocation or suspension, necessary to ensure that the continued importation of this LNG meets the statutory standard."[31]

In May 1983, the FERC ordered Trunkline LNG Company to file monthly reports on the status of these renegotiations. In those reports, the Commission was to be informed of the current status of the talks, the number of negotiation sessions held each month, and whether the contract had been submitted to arbitration. In July of 1983, Panhandle Eastern Corporation announced that Algeria had agreed to a 40% reduction of Panhandle's purchases of Algerian LNG. Panhandle also stated that it planned to file a price adjustment plan with the FERC which would alter the contract formula on which the price of Algerian LNG was based.[32] Shortly after this announcement was made, the FERC, citing continuing delays in price renegotiations, issued a show cause order giving Trunkline 15 days to demonstrate why its authorization to import LNG should not be revoked.[33]

There have been other Federal regulatory actions regarding LNG as well. For example, in January 1983, the Economic Regulatory Administration held a public conference on Canadian and Mexican Natural Gas Imports.[34] Although discussion focused on overland gas imports, twenty-seven Members of Congress filed comments noting that they were "also deeply concerned about the import of even higher cost liquefied [sic] natural gas from Algeria."

In his opening statement at the conference, ERA Administrator Hanzlik noted the concern of some that:

> The price for imported gas is too high and that the current mechanism for establishing prices does not assure that imported gas will be competitive in U.S. markets in the future. [Thus,]
>
> We are seeking your suggestions for an approach that would permit pricing arrangements responsive to market forces and the public interest.[35]

Later, Administrator Hanzlik stated that following a second conference, a new approach to import regulation will be announced. One report stated that the new policy will reflect DOE's intent to allow buyers and sellers flexibility in world markets by focusing on broad policy objectives rather than the specifics of price.[36]

[29] *Supra* note 26, at 36-38.
[30] Federal Energy Regulatory Commission News Release regarding Docket Nos. CP74-138-003 (Feb. 23, 1983) Federal Energy Regulatory Commission Docket No. CP74-139 (May 27, 1983).
[31] Inside F.E.R.C., March 7, 1983, at 10.
[32] The Wall Street Journal, July 12, 1983, at 26, col. 1.
[33] The Energy Daily, July 21, 1983, at 1.
[34] In the Matter of the ERA Conference on Overland Imported Natural Gas, January 18, 1983.
[35] *Supra* note 34, prepared comments of ERA Administrator Ray Hanzlik, at 1, 2.
[36] Inside F.E.R.C., Aug. 1, 1983, at 4.

Federal Legislation — Over the past year, several bills concerning LNG pricing were introduced in the Congress. Generally, such bills would impose more stringent criteria upon importers seeking import authorization. One, H.R:1441, introduced by Rep. Corcoran (R-IL) the "Natural Gas Import Policy Act of 1983,"[37] would suspend authorization of any natural gas import until a new contract price has been set by the government of the exporting country and filed with the Secretary of Energy and the Federal Energy Regulatory Commission within 9 months after the passage of the bill. It would allow the recovery of "prudently" incurred costs of construction of terminals receiving Algerian LNG even if import authorization were suspended under the Act. However, no rate of return would be permitted on such costs.

Another bill, S.370, the "Imported Liquefied Natural Gas Policy Act of 1983"[38] (Sen. Percy, R-IL) would set the ceiling rate for regasified, imported LNG at the average price of No. 6 fuel oil during each most recent 90 day period. However, Section 1 of that bill would authorize FERC and the Secretary of Energy to set the rate above the price of No. 6 fuel oil, if it were established that:

1. Alternative supplies of natural gas are not available in sufficient volume or at a sufficiently low price;
2. The supply of LNG would come from a source which is reasonably secure from political and technical interruption; and
3. The contract allows for a reduction in price or volume should alternative supplies become available.

Public Utility Commission Actions — A few state public service commissions have been reluctant to pass on the higher costs of supplemental gas supplies. In a 1982 rate proceeding, the West Virginia Public Service Commission held that Columbia Gas of West Virginia needlessly had purchased higher-priced synthetic natural gas from Columbia LNG Corporation, when lower-priced gas was available to it.[39] That Commission then limited Columbia Gas to a rate increase of $65 million, $30 million less than the company had originally requested, despite Columbia's objections and its showing that the Commission's decision would cause it severe financial hardship.

In 1982, the Illinois Commerce Commission (ICC) issued a show cause order asking Illinois utilities to explain why the Commission should not block the passthrough of higher cost gas, including Algerian LNG, to consumers.[40] Apparently, the ICC intended to warn importers that the LNG may not be marketable. The Illinois proceeding is still pending and its ultimate resolution could have far-reaching ramifications upon potential LNG trade.

c. *Timing*. Timing also has adversely affected LNG growth. LNG, as a new product and technology trying to enter the U.S. market in the 1970's, faced

[37] H.R. 1441, 98th Cong., 1st Sess. (1982).

[38] S. 370, 98th Cong., 1st Sess. (1982).

[39] *Columbia Gas of West Virginia, Inc.,* West Virginia Public Service Commisison, Case Numbers 80-336-G-30C, 81-366-G-30C, June 28, 1982.

A new statute passed by the West Virginia legislature adds to the difficulty in marketing natural gas in that state. Under a substitute for Senate Bill No. 17, passed on March 12, 1983, and signed into law on March 15, 1983, the Public Service Commission must first determine if a utility purchased the lowest price available gas before a rate increase may be granted. Article 24, Chapter 11 W. Va. Code § 11 (1931), as amended.

[40] Illinois State Commerce Commission, Hearings on the passthrough of the costs of higher-priced natural gas, Docket Number 82-0059, August 25, 1982.

obstacles including legal challenges[41] in a new age of consumerism and environmentalism. To allay public concerns, numerous studies testing the limits of LNG technology were made. The ability of the industry to avoid leaks or spills was thoroughly documented. In one such study by the U.S. Coast Guard, researchers were unable to prove that LNG in vapor form will detonate in open air.[42] Further, technological advances in the design of LNG storage tanks, tanker ships, and systems to prevent the release of LNG at peakshaving facilities, have successfully minimized safety and environmental risks involved in shipping and storing LNG.

d. *Legal and Regulatory Restraints.* Finally, as discussed in Part III *infra,* the frequently burdensome and conflicting regulation of the U.S. gas industry at the Federal and state levels has not always been flexible enough to adapt quickly to the rapidly changing market into which LNG is sold.

5. *The Outlook for U.S. Gas Pricing and Demand*

a. *Gas Pricing.* The gradual decontrol of U.S. natural gas wellhead prices is bringing the price of domestic gas to higher but more realistic levels relative to petroleum and other fuels. This is a positive development for the maintenance of a viable LNG trade, but the transition has been painful, and has served to highlight the problems which the heavily regulated U.S. natural gas industry faces in adjusting to competition with other fuels, some of which are unregulated. In addition, the international recession, depressed oil prices, contracting practices such as high take-or-pay requirements and obsolete statutory constraints (discussed in detail in Part III) on gas use have created further LNG marketing difficulties.

Gas prices paid by residential and commercial gas consumers increased at national average rates of 17% per year between 1978 and 1982, causing great concern among such consumers. Industrial rates increased at an average of 18% per year.[43] As the price of oil softened in 1981-1982 and the price of gas continued to rise under the NGPA, the price of gas began to exceed marketable levels on many U.S. gas systems, resulting in an estimated net switching of 515 Bcf from gas to oil from 1981-1982. U.S. industrial gas sales by utilities were down an estimated 15% in 1982 compared to 1981, resulting in a decline in total gas utility sales of 5%. Approximately one-half of this load loss was due to the recession.[44]

In spite of these price increases, natural gas remained the U.S. residential and commercial consumer's least expensive major fuel. Consumers have responded to this price advantage. Nearly 452,000 U.S. househeating units converted to natural gas in 1981, the second highest level ever recorded.[45] There were an estimated 38,400 commercial conversions to gas in 1981.[46]

Nevertheless, gas prices in the U.S. are at or near market clearing levels,

[41]*See Hollister Ranch Owners Association and the Santa Barbara Citizens for Environmental Defense v. Department of Energy,* U.S. Court of Appeals for the District of Columbia Circuit, Docket Nos. 78-2207, 79-2188, 79-2390, 79-2391, 79-2396, 79-2444 and 80-1115 (filed Oct. 19, 1979).

[42]For the detonation study *see* U.S. Office of Technology Assessment, Transportation of Liquefied Natural Gas (1977); for related studies *see* Pacific Northwest Laboratory, Analysis of LNG Peakshaving Facility Release Prevention Systems, study prepared for the U.S. Department of Energy (1982); and Pacific Northwest Laboratory, Comparative Safety Analysis of LNG Storage Tanks, study prepared for the U.S. Department of Energy (1982).

[43]*Supra* note 18.

[44]American Gas Association, Energy Analysis: Survey of Industrial Fuel Switching and Alternative Fuel Capability, 1981-82, 2, (Update) (September 1982).

[45]American Gas Association, Energy Analysis: An Analysis of Residential Spaceheating Conversions to Natural Gas in 1981 (Update), 1, (September 1982).

[46]American Gas Association, Energy Analysis: Analysis of the 1981 Commercial Gas Market (Update), 1, (November 1982).

especially in the industrial market.[47] Thus, it is essential for LNG to be priced over the long term by exporters, such that its cost, after delivery and regasification, will be competitive with alternative fuels in the U.S. gas marketplace, particularly in the industrial market where many users can easily switch from gas to competing fuels.

(b) *Gas Demand.* Currently, demand for gas in the United States is about 20 Tcf/year.[48] The gas industry's recent gas demand study indicates that by the year 2000 the growth in demand for gas above current levels will come primarily in the expansion of traditional commercial and industrial uses and in new markets. The expansion of traditional industrial use will depend significantly on gas prices relative to competing fuels and on the economy. However, new premium gas markets are expected to develop. These premium markets, which can utilize the environmental and other advantages of LNG, will be very important to increased LNG use. A discussion of some of these new markets follows:

(i). *The Select Use of Gas for Environmental Compliance Purposes in Industry and Powerplants.* Some regulators and environmental groups in the U.S. have noted that selective increases in natural gas combustion under boilers in conjunction with other fuels can be a low cost means of controlling air pollution.[49] At the 1982 International Conference on Combined Combustion of Coal and Gas, hosted by Case Western Reserve University in Cleveland, Ohio, the conferees identified more than 10 examples where such "select" gas use now is employed or proposed, enabling increased and more efficient use of such high-sulphur fuels as coal and residual oil, while maintaining air quality.[50] In an A.G.A. study, the annualized cost of converting 12 New England powerplants from oil to coal with select gas use was found to be 22% less expensive than continuing to operate these plants on oil and 10% less than converting to coal with scrubbers. The capital costs for select use of gas were only half of those for the scrubber option.[51] A University of Florida study found that conversion of that state's 12,678 megawatts of oil boiler electric powerplant capacity to coal with select use of gas could reduce power generation costs by $2.5 billion (50%) per year compared to remaining on oil.[52] Typically only 20-30% of the energy consumed in such applications would be gas, but such use can be a premium priced firm demand application.

(ii). *Natural Gas as a Vehicular Fuel.* Experience in the U.S. and elsewhere has demonstrated the air quality, low maintenance, and resource efficiency advantages of natural gas, from whatever source, as a vehicular fuel. Compressed natural gas (CNG) vehicles require only 85% to 97% of the primary energy required by equivalent gasoline-powered vehicles, and 54% to 62% of the electricity requirement for small electric vehicles. Also, when the full energy cycle from extraction to end-use is considered, using natural gas as fuel would result in substantially lower criteria air emissions than electric vehicles, resulting in less than

[47] Inside F.E.R.C. 10 (August 1, 1983).

[48] Of this total: residential sales were 4.6 Tcf, commercial sales 2.4 Tcf and industrial sales 8.2 Tcf. Industrial and powerplant use accounted for over half of U.S. gas sales. Approximately 52% of U.S. gas sales in the industrial sector and over 89% of electric generation sales are to dual-fuel capable users. In the industrial sector, residual oil is the primary alternative fuel for 49% of the dual-fuel capable use, while in the electric generation sector, residual oil is nearly always the alternative fuel. Thus, the high volume industrial and electric generation users can switch from gas to oil if there is a price advantage to doing so, *supra* note 44.

[49] Bardine, "Combined Gas/Coal Burning — A New Way to Satisfy Both Environmental and Fuel Use Regulations, 2 Energy Economics, Policy and Management 19 (1983).

[50] Case Western Reserve University, Proceedings of the 1982 International Conference on the Combustion of Coal and Gas (December 1982).

[51] American Gas Association, Energy Analysis: An Economic Comparison of Oil, Scrubbed Coal, and Select Gas Use With Coal in New England Power Plants, 3, (March 1981).

[52] AN ALTERNATIVE TO OIL: BURNING COAL WITH GAS, 2, (A.E.S. Green ed. 1981).

1% of the sulfur oxides and total suspended particulates, 54% of the nitrogen oxides, and 30% of the carbon monoxide emissions compared to the electric alternative.[53]

Some 30,000 natural gas powered vehicles currently are operating in the United States.[54] New vehicles specially designed to utilize natural gas, both for fleet and commuter vehicles, could significantly increase market penetration in the next two decades. The Ford Motor Company has taken a major step in this direction with the 1982 unveiling of its Alternative Fuel Vehicle (AFV) which can utilize CNG or liquid fuels.[55] The passage of the Methane Transportation Research, Development and Demonstration Act of 1980,[56] should provide additional impetus for CNG vehicles. This Act authorized the Department of Energy to sponsor research, and encourages the use of natural gas vehicles by Federal agencies. Further progress is necessary, however, in developing greater mileage range for CNG vehicles, low pressure on-board CNG storage systems, new compressor systems and appropriate codes and standards relating to CNG vehicles and their use.

(iii). *Gas-Fired Cogeneration.* Cogeneration, in which the waste heat energy from electric power generation is captured and utilized, has received increased attention in recent years.[57] FERC's issuance of regulations to encourage cogeneration interconnection and sales to utilities, as mandated by the Public Utilities Regulatory Policies Act of 1978,[58] has encouraged the utilization of this technology. A recent analysis of a representative industrial facility showed that a gas-fired cogeneration system could use 37% less net primary energy than an oil-fired cogeneration alternative and could be 24-53% less expensive than using a conventional gas boiler to meet thermal requirements, while meeting electricity requirements by purchasing electricity from the grid.[59] Similar results were found for a representative large commercial application.[60]

Demand for gas in traditional markets and new markets will be determined by the interaction of a number of variables. Beyond normal gas demand growth, which will result from growth in the U.S. economy, some 4.5 million barrels per day of U.S. oil consumption can be replaced by gas and coal in stationary applications.[61] Thus, a national energy policy of less dependence on foreign oil and increased LNG imports could have a significant impact on gas demand. It has been suggested that new gas markets could rise to between 1.6 Tcf and 4.9 Tcf of sales annually in the U.S. by the year 2000.[62] It also has been suggested that gas could increase its share of U.S. end-use energy markets from the current 27% level to a range extending up to 30% by the year 2000. According to one study, there can be adequate markets for the 23 to 31 quads of gas supply projected for 2000, given the right environment.[63]

[53] Aerospace Corporation, for the U.S. Department of Energy, Vol. III, Assessment of Methane-Related Fuels for Automotive Fleet Vehicles, pp. B-19-B-25 (February 1982); American Gas Association, Energy Analysis: An Economic, Efficiency, and Environmental Comparison of Alternative Vehicular Fuels (1982 Update), 4, (May 1982).

[54] *Supra* note 3, at 30.

[55] *Supra* note 3, at 32.

[56] 15 U.S.C. §§ 3801-3810 (Supp. V 1982).

[57] Drennan, *Considering the Cogeneration Commitment: Do Government Incentives Tip the Scales?* 1 Energy L. J. 297 (1980).

[58] The Public Utility Regulatory Policies Act of 1978 is codified in various sections of Titles 15, 16, 30 and 42 of the U.S. Code.

[59] American Gas Association, Energy Analysis: An Energy Conservation and Economics Analysis of Gas-Fired Cogeneration in Commercial and Industrial Applications (Sept. 14, 1981).

[60] *Supra* note 59.

[61] American Gas Association, Energy Analysis: Recent and Potential Substitution of Oil with Gas and Coal in Non-Transportation Uses, 2, (December 1981).

[62] Demand Outlook, *supra* note 3, at 3.

[63] Demand Outlook, *supra* note 3, at 4.

III. Legal, Regulatory and Other Policies Affecting Future LNG Trade in the United States

For U.S. LNG trade to reach its potential, there must be: (1) government support for a consistent, long range policy to encourage increased use of LNG; (2) substantive changes in laws and regulations to allow gas prices to remain within competitive levels, to remove obsolete demand restraints on gas use and to encourage more flexible rate policies and tariffs; and (3) procedural reforms to reduce delays and regulatory burdens which may inhibit increased LNG use.

1. *Public Policy Support*

Virtually every major operational aspect of the U.S. gas industry is regulated at Federal, state and sometimes local levels.[64] Long lead times and large financial commitments are characteristics of major new LNG projects. For example, a typical LNG gasification facility may cost $500 million or more and may take from six to ten years or more from conception to completion.[65] Thus, the U.S. must set a sound, long term energy course for LNG use and then follow it despite temporary price fluctuations.

2. *Substantive Legal Changes to Encourage Gas Use*

a. *Gas Contract Legislation.* No new LNG or other gas supplies will be developed unless they can be sold. Thus, it is essential that gas prices remain within marketable levels. While phased gas deregulation under the NGPA has been successful in bringing forth new gas supplies, two gas pricing contract problems threaten to drive gas to unmarketable prices: excessive "take or pay for" provisions and onerous indefinite gas price escalation clauses. Take or pay for clauses between U.S. producers and pipelines require that a specified minimum percentage of gas deliverability or contracted volumes be paid for whether taken or not.[66] Very high minimum take provisions for U.S. conventional supplies, such as 80 or 90 percent of production capacity, are excessive given current gas markets. Unreasonable escalator clause provisions, which could cause gas prices to exceed marketable levels upon decontrol, should continue to be examined and revised.[67]

b. *Incremental Pricing and The Power Plant and Industrial Fuel Use Act of 1978.* There are two specific Federal restraints on industrial gas marketing: the incremental pricing provisions of the NGPA[68] and the Powerplant and Industrial Fuel Use Act of 1978[69] (FUA).

[64] 2 REGULATION OF THE GAS INDUSTRY 4-3, 4-60 (American Gas Association ed. 1981). American Gas Association, Gas Rate Fundamentals 3d Ed. 84-99 (1978).

[65] 13 LNG Digest, at 3 (June 1982).

[66] 3 REGULATION OF THE GAS INDUSTRY, Glossary-158 (American Gas Association ed. 1981).

[67] Testimony of George H. Lawrence, President of the American Gas Association, Before the Committee on Energy and Natural Resources, United States Senate (December 13, 1982); In the Matter of Petition to the Federal Energy Regulatory Commission and the Economic Regulatory Administration, of the Process Gas Consumers Group and American Iron and Steel Institute to Investigate and Establish Rules Relating to the Importation of Natural Gas (No docket number assigned) (Dec. 21, 1982).

[68] 15 U.S.C. §§ 3341-3348 (Supp. II 1978).

[69] 42 U.S.C. §§ 8301-8355 (Supp. II 1978).

NGPA incremental pricing was designed primarily to shelter residential and commercial customers from the rising gas costs resulting from phased deregulation. It charges such costs to industrial customers first, until industrial prices reach periodically determined ceilings. Under current law, incremental pricing is required for all LNG imports approved after May 1, 1978.[70] Incremental pricing should be repealed, however, because (a) it encourages excessive imported oil use over gas use, particularly in the industrial market, (b) has failed as a "market ordering device" and (c) is administratively burdensome.[71]

FUA arose out of a concept in the late 1970s that the U.S. was rapidly running out of gas and thus industrial gas use must be severely restricted.[72] It overlooked the great quantity of potential gas resources that could be developed under proper pricing policies as well as the great potential of worldwide gas resources. Section 202 of FUA bans natural gas as a primary energy source in large new electric powerplants and new major fuel burning installations (MFBIs)[73] unless there is a formal exemption by the Department of Energy (DOE). In addition, Section 302(a) of FUA[74] allows DOE to bar gas use in an existing MFBI if certain criteria are met including whether it was or is technically capable of using coal and if it is financially feasible to do so.

FUA inhibits industrial demand for gas. For example, the select use of gas in conjunction with coal in new industrial facilities, to reduce acid rain and for other environmental control purposes, is hindered by uncertainty as to whether such use is permissible under FUA. Although DOE may grant exemptions from FUA (a) where its provisions conflict with "applicable environmental requirements,"[75] or (b) where certain fuel mixtures are used,[76] it is not clear that the select use of gas for increased coal burning would qualify under either such exemption. In addition, FUA creates uncertainty in the minds of industrial gas users. Existing MFBI's can be ordered by DOE to switch to alternate fuels.[77] Thus, DOE can expand or contract this important market at any time by regulatory action.

FUA should be repealed or at least amended to permit increased industrial gas use, remove marketing uncertainty, reduce U.S. reliance on oil imports and encourage the select use of gas. FUA amendments should (a) allow new MFBIs to use gas; (b) formally exempt existing MFBIs from FUA, (consistent with DOE's current but discretionary regulations); and (c) establish a clear statutory exemption for the select use of gas.

c. *Flexible Rates.* As gas prices approach competing fuel levels in many markets, it is essential that gas companies have the regulatory flexibility to adjust quickly to market conditions in order to prevent load loss. This is particularly true in the highly competitive industrial gas market which faces competition from both unregulated

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[70] 15 U.S.C. § 3347 (Supp. II 1978).

[71] For further discussion, see Mogel & Mapes, *Assessment of Incremental Pricing Under the Natural Gas Policy Act,* 29 Cath. U. L. Rev. 763 (1978); Muchow, *The Future of Gas Energy,* 2 Energy L. J. 241, 279 (1981).

[72] S. Rep. No. 95-361, 95th Cong., 2d Sess. 28, 29 *reprinted in* 1978 U.S. Code Cong. & Ad. News. 8173, 8174.

[73] 42 U.S.C. § 8306 (Supp. II 1978).

[74] 42 U.S.C. § 8312 (Supp. II 1978).

[75] 42 U.S.C. § 8351 (a) (1) (c) (Supp. II 1978).

[76] 42 U.S.C. § 8351 (d) (Supp. II 1978).

[77] 42 U.S.C. § 310 (Supp. II 1978).

residual oil and coal. Federal and state regulators increasingly are reviewing or considering amending existing tariffs and policies to provide such flexibility. They appear to realize that if load losses occur, more fixed costs must be passed on to other customers including residential users.[78]

Several pipelines have asked FERC's approval on a variety of innovative competitive marketing plans. These include sales incentive rates to increase gas volumes sold (thereby reducing take-or-pay obligations), the establishment of spot-markets, programs under which pipelines would act as brokers for direct purchases of gas, and rates which may be adjusted monthly.[79] At the state level, flexible industrial gas rates which are pegged to the posted price of alternative fuel oil also are becoming more common.[80]

Clearly, this need for flexibility in rates also applies to LNG pricing arrangements with producing nations. The contract provisions for LNG must recognize the highly competitive environment in which gas must be sold and the producer's contract terms for LNG must contain the needed flexibility.

d. *Proper Regulatory Treatment for Natural Gas Vehicles.* Regulatory flexibility is necessary to develop the new gas vehicles market. Assisting this development is the statutory exemption[81] from FERC's Natural Gas Act jurisdiction of sales of gas in interstate commerce for resale, which is allowed to distribution companies which sell gas for local distribution. In the 1982 Ni-gas[82] case, FERC held that this exemption would not be lost in the case of sales for use in compressed natural gas (CNG) vehicles, as long as the CNG is injected locally into vehicle fuel tanks.

e. *Cogeneration and the Select Use of Gas.* Several developments have occurred which affect the growing gas congeneration market. First, in the American Paper Institute case,[83] the Supreme Court recently upheld two regulations issued by FERC[84] under the authority of Section 210 of PURPA,[85] which provide important incentives to cogeneration. The first regulation requires electric utilities to purchase electric power from, and sell back-up power to, cogenerators at the "avoided cost" i.e., the marginal cost to the utility to produce the increment of additional electricity itself, or to purchase it from an alternative source.[86] The second regulation provides

[78]American Gas Association, White Paper on Gas Distribution Industry Ratemaking Options (April 1983), 49.

[79]Columbia Gas Transmission Corp., Federal Energy Regulatory Commisson Docket No. CP82-485-000; Tenneco Oil Corporation, Federal Energy Regulatory Commission Docket No. CI83-269-000; Columbia Gas Transmission Corp., Federal Energy Regulatory Commission Docket No. RP82-120; Panhandle Eastern Pipe Line Co.; Federal Energy Regulatory Commission Docket No. CP83-333; Michigan Wisconsin Pipeline Co,. Federal Energy Regulatory Commission Docket No. CP82-542.

[80]E.g., Large Volume Dual-Fuel Service Rate of Providence Gas Co., Rhode Island Public Utility Commission Docket No. 45. Effective Oct. 1, 1982; Schedule 6 - LV1 - Large Volume Interruptible Gas.

[81]15 U.S.C. § 717c, § 717a-w (Supp. II 1978).

[82]*Northern Illinois Gas Co.,* Federal Energy Regulatory Commission Docket No. G-10632-004, Order Granting Petition for Declaratory Order and Granting Petitions to Intervene (August 27, 1982).

[83]*American Paper Institute v. American Electric Power Service Corporation, Federal Energy Regulatory Commission v. American Electric Power Service Corporation,* 51 U.S.L.W. 4547, (May 16, 1983). The U.S. Court of Appeals for the District of Columbia had struck down these regulations in 1982. *American Electric Power Service Corporation v. American Paper Institute; American Electric Power Service Corporation v. Federal Energy Regulatory Commission,* 675 F.2d 1226 (1982). *reh. den.* 675 F.2d 1246 (1982).

[84]Rates for Purchase. 18 C.F.R. 292.304 (b) (2) 1981: 18 C.F.R. 292.101 (b) (6) (1981); Electric Utility Obligations Under this Subpart, 18 C.F.R. 292.303 (1982).

[85]16 U.S.C. § 824 (Supp. II 1978).

[86]According to the Court of Appeals, the Commission had failed to show that the avoided cost rate was "just and reasonable to the electric consumer of the electric utility" and was "in the public interest," as required by PURPA. *American Electric Power Service Corporation, supra* note 83, at 1228. However, in upholding the rate, the Supreme Court stated that the Commission had done an "adequate" job of meeting PURPA's criteria. *American Paper Institute, supra* note 83, at 4550.

that no evidentiary hearing under the Federal Power Act[87] is required prior to a Commission order regarding interconnection between a utility and a cogenerator.[88] The decision eliminates a major uncertainty which has inhibited cogeneration development, and streamlines the application process.

Second, the existing 10% cogeneration Federal energy tax credit expired in 1982.[89] Legislation[90] was proposed in the 97th Congress to reinstate and increase the size of the credit but the Administration has proposed revocation of all energy tax credits.

Finally, despite provision under Section 212(c)[91] of the Fuel Use Act for permanent exemptions, that Act has been a continuing obstacle to the development of new gas-fired cogeneration facilities. Regulations promulgated in 1982 by the ERA, however, substantially eased the barriers to obtaining an exemption from the FUA by clarifying that exemptions are not restricted by the amount of elecricity resold.[92]

The clarification of PURPA standards by the Supreme Court, enactment of expanded federal tax credits and new FUA regulations could provide valuable incentives to the gas-fired cogeneration market.

Regarding select use of gas with coal and other fuels, the FUA restrictions described above[93] are relatively simple compared to the clean air laws. In addition to the federal Clean Air Act,[94] several states have their own laws and regulations as do some localities.[95] There should be clear, uniform national guidelines from the Environmental Protection Agency (EPA) to remove regulatory uncertainty regarding select use of gas.

3. *Regulatory Reform.*

Because the gas industry is "affected with the public interest,"[96] regulation in many areas such as safety is necessary and desirable. However, overlapping layers of Federal and state regulation, and regulatory delays and uncertainties unnecessarily add to the cost of LNG projects and restrict LNG markets.

Section 3 of the Natural Gas Act[97] provides, for example, that before LNG may be imported into the United States, the Federal government must find such import "not inconsistent with the public interest." Both the Economic Regulatory Administration (ERA) and the FERC are involved in this determination. The ERA reviews imports on the basis of such factors as price, security of supply, and regional

[87] The Federal Power Act is codified in various sections of Title 16 of the U.S. Code.

[88] In overturning the Court of Appeals decision, The Supreme Court upheld the FERC rule exempting cogeneration from the evidentiary hearings required under Sections 210, 211 and 212 of the Federal Power Act ((16 U.S.C.A. § 824i, 824, and 824k (1976). The Supreme Court found that FERC's interpretation of the statutory scheme created by PURPA and the Federal Power Act was a reasonable one, and did not violate the Federal Power Act. *American Paper Institute, supra* note 83, at 4552.

[89] The Revenue Act of 1978, 26 U.S.C. § 48 (1976).

[90] Industrial Energy Security Tax Incentives Act, S. 750, 97th Cong. 1st Sess., H.R. 2640, 97th Cong. 1st Sess. (1981).

[91] 42 U.S.C. § 8352 (Supp. II 1978).

[92] Permanent Exemptions for New Facilities; Cogeneration. 10 C.F.R. 503.37 (1981).

[93] *Supra* notes 74 and 73.

[94] Clean Air Act of 1973, 85 Stat. 464, as codified in various sections of Title 42 of the U.S. Code; amended by the Clean Air Act Amendments of 1977, 91 Stat. 685, as codified in various sections of Titles 15 and 42 of the U.S. Code.

[95] E.g., *See* CAL. HEALTH AND SAFETY CODE, § 425 (Deering 1982).

[96] *Munn v. Illinois*, 94 U.S. 113 (1877).

[97] 15 U.S.C. § 717b (Supp. II 1978).

and national need for the gas. In additon, the ERA may attach terms and conditions to import authorization orders issued by FERC.[98] The FERC must approve the siting, construction and operation of facilities to receive the imported gas. The FERC's authority also includes all other matters not specifically delegated to the ERA.[99] In the past, the U.S. government has been unduly restrictive in allowing LNG imports.[100] On occasion, for example, Section 3 proceedings and litigation arising out of them have been used to frustrate or delay approval of LNG projects.[101]

There are many laws in each state such as health and safety, and environmental codes affecting LNG directly or indirectly. Taken together, these Federal and state laws are so numerous that hundreds of separate permits and certificates may be required to construct one LNG facility.[102]

Many in the U.S. gas industry are concerned about the long delays and uncertainties which exporters have experienced in obtaining LNG import licenses from the U.S. Because the technology of and operating know how for LNG are proven, regulatory and judicial review of such projects should be streamlined. A reasonable examination of projects to avoid adverse economic and environmental impacts and to reduce safety hazards both on-shore and in shipping is appropriate. However, Federal and state regulations should be reviewed with the goal of permitting the marketplace to choose freely among energy alternatives and encouraging the increased use of gas including LNG at marketable prices. This review should have as its goals:

1. A net reduction in the number and complexity of regulations governing energy company operations;
2. Better agency oversight by Congressional committees to streamline existing legislation where necessary and to identify and eliminate unreasonable Federal regulatory requirements; and
3. Careful regulation by well-managed, accountable, knowledgeable regulators acting under fixed time schedules but with flexible administrative procedures.

IV. Conclusion

The long range future for increased U.S. LNG imports can improve as we move through current gas price readjustments toward market-determined gas prices. New premium gas markets and increased regulatory flexibility also should contribute to a better U.S. environment for LNG. As in the past, sustained public and government support is essential to such progress.

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[98] D.O.E. Delegation Order No. 0204-4 (Oct. 1, 1977), 42 Fed. Reg. 60726 (Nov. 29, 1977).

[99] *Id.*

[100] *Supra* note 23. *See also* Muchow, *supra* note 71, at 260.

[101] *El Paso Eastern Co.*, Economic Regulatory Administration Docket Number 77-006-LNG; Federal Energy Regulatory Commission Docket Number CP77-330, December 21, 1978; *Tenneco Atlantic Pipeline Co.*, Economic Regulatory Administration Docket No. 77-010-LNG, Opinion No. 3, December 18, 1978. For further discussion of this issue, *see* The Future of Gas Energy, *supra* note 62, at 260.

[102] *Supra* note 41.