**Energy Material Transport,
Now Through 2000
System Characteristics and
Potential Problems**

**Task 4 Progress Report -
Natural Gas Transportation**

July 1978

**Prepared for the U.S. Department of Energy
under Contract EY-76-C-06-1830**

**Pacific Northwest Laboratory
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ENERGY MATERIAL TRANSPORT, NOW THROUGH 2000
SYSTEM CHARACTERISTICS AND POTENTIAL PROBLEMS
TASK 4 PROGRESS REPORT - NATURAL GAS
TRANSPORTATION

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FOREWORD

This report is an account of progress in Task 4 -- Natural Gas Transportation, of the project "Energy Material Transport, Now Through Year 2000, System Characteristics and Potential Problems." The project is sponsored by the Department of Energy, Division of Environmental Control Technology, Transportation Branch.

The overall objectives of this project are:

- to assess potential problems which may hinder the safe, environmentally acceptable, and cost-effective development of nuclear and fossil energy material transportation systems in the United States from now until the year 2000.
- to recommend research, development and other necessary action to mitigate the potentially adverse impact of these problems on transportation system development.

Project coordination and research effort in this task was provided by the Pacific Northwest Laboratory.^(a) Major technical contributions to the Task 4 study were made by staff members of Battelle, Columbus Laboratories.

The results of effort addressing other tasks in this project are reported as follows:

- Task 1 - Nuclear Material Transportation (BNWL-2066, BNWL-2248)
- Task 2 - Coal Transportation (PNL-2420)
- Task 3 - Petroleum Transportation (PNL-2421)

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ENERGY MATERIAL TRANSPORT, NOW THROUGH YEAR 2000,
CHARACTERISTICS AND POTENTIAL PROBLEMS

TASK 4 PROGRESS REPORT - NATURAL GAS TRANSPORTATION

1.0 SUMMARY

This report contains a summary characterization of the existing natural gas transportation system and an assessment of some potential problems which may impact natural gas transportation in the United States during the balance of the century. A primary purpose of this task is to provide information and perspective that contributes to the evaluation of research needs and priorities in future programs.

This assessment focuses on safety and environmental issues that should concern the gas industry, the Department of Energy (DOE) and other cognizant government agencies. Specific potential problems are identified which warrant additional programmatic effort because they do not appear to be receiving adequate attention. New programs are recommended to address these concerns according to their apparent importance, under conditions known or anticipated in early 1978. Other safety and environmental concerns in natural gas transportation are also reviewed, and judged to be adequately addressed in ongoing programs. No additional effort appears to be needed in these areas at present.

1.1 POTENTIAL PROBLEMS, RECOMMENDED EFFORT AND PRIORITIES

Further research is recommended on the following potential problems, identified as needing attention in addition to the efforts being applied in other relevant programs. The recommendations include judgments of the priority and level of effort that should be considered in future program plans. The specific involvement of the sponsor of this study^(a) in new programmatic action is recommended where considered to be appropriate.

(a) DOE Division of Environmental Control Technology (DECT).

1.1.1 Transportation of New Fuel Types in Existing Gas Pipelines

Safety hazards may result from the proposed transportation of new fuel types in existing natural gas pipeline systems. Alternative gaseous fuels, such as high or low-Btu gas, synthetic natural gas (SNG) and hydrogen, contain compounds that may react with and degrade materials in existing pipeline systems. Safe and environmentally-acceptable plans for transporting these gases should be developed before new gas plants come on line.

A study is needed to determine whether modifications or additional requirements are necessary so that pipeline systems may safely transport other gaseous fuels. Data on possible environmental effects caused by releases of these new fuels should be gathered and evaluated to provide guidelines for siting requirements, the retrofitting of existing pipeline systems, and any new pipeline design standards that may be required. A moderate priority is suggested for a one to two man-year level of effort in FY 1979 to address this concern. The DECT should be involved in aspects of this work.

1.1.2 Contingency Supply Planning for Emergency Conditions

Natural gas transportation systems may be inadequate to supply future regional demands under some emergency conditions. There does not appear to be an overall contingency plan for natural gas transportation in the event that a major part of the system is shut down under emergency conditions such as those resulting from accidents, sabotage, or natural disasters.

The natural gas transmission and distribution system should be included in a network analysis of all energy distribution systems to provide a data base for the contingency planning of energy material transportation on a national scale. A vulnerability study is needed to determine the impact of specific emergency scenarios on each transportation mode. Safety and environmental effects of possible sudden interruptions in the gas supply should also be assessed.

The planning of energy material transportation for emergency conditions is considered a national priority requiring DOE attention, interagency effort and industrial involvement. In support of this, the DECT should initiate a moderate priority effort, at a suggested half to one man-year level in FY 1979, to assess potential consequences of gas supply interruptions.

1.1.3 Possible Effects of Major Natural Disasters

Major natural disasters causing extensive damage to gas distribution systems could result in fires and explosions in populated areas. The hazard potential may be increasing steadily as both industrial development and populations expand in the vicinity of gas distribution and transmission pipelines. No specific research in this area is apparent.

A risk assessment would be useful in projecting the potential impact of major natural disasters based on the probability of occurrence. This assessment should be used to determine if new emergency shutdown and protection techniques may be needed, and should include impacts on underwater pipelines. Initial effort in this risk assessment is judged to require a half to one man-year effort and should be considered in DECT program planning for FY 1979 or FY 1980 at a low to moderate priority.

1.2 LATENT CONCERNS

This report identifies three potential problems as only latent concerns because they appear to receive sufficient attention in current programs. Latent areas of concerns include hazards resulting from pipeline corrosion, the deterioration of older distribution systems and third-party damage to pipelines.

Comprehensive Federal regulations and the active research and development programs sponsored by the gas industry and government that address these concerns are judged to be adequate. Additional effort does not appear to be warranted, although this situation may change depending on the results of current programs and future conditions. While no specific new effort is recommended, the gas industry and cognizant government agencies should monitor possible future trends that might increase the importance of these concerns and produce a need for new action in these areas.

1.3 OVERVIEW

Major potential problems affecting the future development of natural gas transportation systems are the availability of new supply sources and the incentives to develop them. The supply problem appears to be receiving adequate attention in a broad spectrum of ongoing research, development and engineering programs funded by industry and government. The incentives to develop new sources will be directly influenced by national energy policies and Congressional action. Many problems relating to safety and the environment are adequately covered in the programs sponsored by the American Gas Association (AGA) and the Gas Research Institute (GRI). The specific action recommended in this report addresses apparent gaps in the coverage of these ongoing programs.

2.0 INTRODUCTION

Natural gas is a significant domestic fuel; in 1975 natural gas represented 38 percent of the total U.S. energy supply, compared to 30 percent for oil and 24 percent for coal. In 1975, natural gas supplied the U.S. with 28 percent of its energy needs and provided over 40 percent of the energy used by industry. However, since 1970, the U.S. rate of natural gas consumption has been greater than the discovery of new reserves. Annual natural gas production has declined steadily from a peak of 22.6 trillion cubic feet (Tcf) in 1973 to a level of 19.5 Tcf in 1976. It is likely that future problems in gas transportation will result from a need to transport supplemental gas supplies, such as SNG and LNG^(a), and gas from newly developed fields, such as Prudhoe Bay in Alaska. In addition, changing patterns of natural gas supply and demand are anticipated to generate problems for the existing natural gas transportation system.

2.1 EMPHASIS AND ORGANIZATION OF THIS REPORT

A primary purpose of each task in this project is to provide information and perspective that may contribute to the evaluation of research, development and engineering needs and priorities and to the structure of future program plans in the area of energy material transportation. This report provides 1) a summary characterization of the existing U.S. national gas transportation system, 2) an assessment and prioritization of potential safety and environmental concerns in natural gas transportation and 3) recommendations for specific programmatic effort to mitigate the anticipated impact of these concerns.

This study addresses potential safety and environmental problems anticipated to impact the transportation of natural gas in the United States between now and the end of the century. The emphasis is on potential problems which do not appear to be receiving adequate attention in current programs. The

(a) Liquid natural gas concerns are specifically not considered in this study.

gas industry and the government fund a broad range of research, development and engineering programs which address potential problems in gas transportation. For example the Gas Research Institute (GRI) entered 1978 with industrial funding of \$28 million, and \$38 million in DOE contracts. GRI expects to increase funding to about \$100 million from industry and \$150 million from DOE within the next five years. These funds will initially be used for gas supply research (60 percent), conservation research (30 percent) and 10 percent for operational and safety projects.

Because of the extensive research effort already underway, only those areas of concern which require additional attention are identified in this report. These relate to the transportation of new fuel types, contingency planning for emergency conditions and the possible effects of major natural disasters.

The use of "Progress Report" in the title is intended to emphasize the potential transitory nature of concern identities and priorities. Several concerns which appeared to be initially of high priority have been resolved or delegated to lower priority during the course of this study. Other potential problems were judged to increase in importance as this work progressed. This report provides a summary assessment of the U.S. natural gas transportation system, future trends and potential safety and environmental problems as they appear to exist or can be forecasted in the first quarter of 1978.

Many details of system characteristics and problem issues that are available in the literature are not discussed in this report. The Congressional Research Service has published detailed reviews and analyses of national energy transportation systems, issues and problems which provide extensive reference material.⁽¹⁾

The balance of this report is organized as follows:

- Section 3 provides a summary characterization of the U.S. natural gas transportation system, including forecasts of supply growth to the year 2000.

- Section 4 contains concern summaries of specific potential problems and consequences, the basis for these problems, related program activities, recommended action and priorities.

- Section 5 reviews concerns that appear not to require additional effort at present.

References are listed in Section 6 and supplemental information is contained in the appendix.

3.0 NATURAL GAS TRANSPORTATION SYSTEM OVERVIEW

A concise summary characterization of the natural gas transportation network currently operating in the United States is presented here to provide perspective on the potential problems and recommendations discussed in Sections 4 and 5.

3.1 PROJECTED NATURAL GAS PRODUCTION SCENARIOS

Over the past 30 years, gross energy consumption in the United States has increased at an annual rate of 2.8 percent. In 1975, natural gas supplied the U.S. with 28 percent of its total energy needs, providing over 40 percent of the energy used by industry. Natural gas is a significant domestic fuel, constituting 38 percent of U.S. domestic resources in 1975, compared to 30 percent for oil and 24 percent for coal.

However, since 1970, the U.S. rate of natural gas consumption has been greater than the discovery rate for new reserves. Annual natural gas production has declined steadily from a peak of 22.6 trillion cubic feet (Tcf) in 1973 to a level of 19.5 Tcf in 1976. This decline is projected to continue unless new gas is discovered in the future and added to U.S. reserves. Producers are already 20 percent short of the natural gas supplies needed to fulfill contractual obligations to interstate pipelines; this is creating gas shortages for industrial users.⁽²⁾

Price regulation is considered to be a major cause of declining natural gas supplies. Regulated gas prices have not been adjusted to stimulate production or to compensate for higher costs of exploration and drilling.⁽³⁾ Only interstate pipeline prices are regulated by the Federal Energy Regulatory Commission (FERC). The intrastate market is not so regulated, and rising intrastate natural gas prices have helped to maintain a fairly stable supply for consumers in gas producing states.⁽¹⁾ Deregulation of natural gas prices might substantially increase the U.S. gas supply. A study by the Congressional Office of Technology Assessment (OTA) concluded that a price for natural gas of \$2.50/Mcf would result in the development of additional reserves amounting to about 50 Tcf over the next 13 years.⁽²⁾

The natural gas pricing issue is presently being debated in the U.S. Senate. Current proposals call for the removal of Federal price controls within five years, with the President and Congress having the right to reimpose them. If this incentive legislation is enacted, a 10 to 15 percent increase in natural gas production may be possible within 3 to 4 years.⁽⁴⁾

Other gas sources are expected to augment dwindling supplies of domestic natural gas. By the year 2000, Alaskan gas, LNG and coal gasification products could add 15 Tcf/year to conventional U.S. supplies. By the year 2000, the proposed Alaskan gas pipeline is projected to supply 3.6 Tcf/year; up to 50 coal gasification plants may be producing a total of 4 Tcf/year; and U.S. imports of LNG could reach 3 Tcf/year.⁽⁵⁾

The importance of pricing policies in natural gas production is reflected in the production forecasts shown in Table 3-1. With continued price regulation, all forecasts show a continuous decrease in production between now and the year 2000. Three of the four sources in Table 3-1, the American Gas Association (AGA), Institute of Gas Technology (IGT) and the former Federal Energy Administration (FEA) estimated that deregulation may permit a slight increase in gas production between 1985 and 1990. All year 2000 forecasts are less than current levels, with or without price regulation. Projections of gas supplies by the Bureau of Mines, Table 3-2, show an increased gas supply in the year 2000.

A forecast by the Exxon Co., U.S.A., projects that by 1990, natural gas will provide only 16 percent of U.S. energy supply.⁽⁶⁾ The President's proposed National Energy Plan (Spring, 1977), estimates 1990 annual gas production at 15.2 Tcf, including offshore resources.⁽⁷⁾ However, a forecast by the AGA predicts that total gas supplies (conventional, imports, synthetic gas, and new technologies) may be as high as 28 Tcf in 1990 and 31 Tcf in 2000.

Current proved natural gas reserves total 216 Tcf. The Potential Gas Committee of the Colorado School of Mines has calculated an estimated mean potential reserve of 948 Tcf of undiscovered natural gas in the United States, equal to the amount of gas discovered to date. In recent years, about 90 percent of total U.S. gas reserve additions have been in intrastate gas reserves, which operate under free market pricing.⁽⁸⁾

TABLE 3-1. Domestic Natural Gas Production Forecasts (Tcf)

<u>Source</u>	<u>1976 Actual</u>	<u>1985 Forecast</u>	<u>1990 Forecast</u>	<u>2000 Forecast</u>
Massachusetts Institute of Technology				
Deregulation	19.5	19.1	NA	15.2
Continued Regulation	19.5	16.1	NA	11.4
American Gas Association				
Deregulation	19.5	20.0	20.1	17.4
Continued Regulation	19.5	16.1	14.6	11.6
Institute of Gas Technology				
Deregulation	19.5	21.6	NA	NA
Continued Regulation	19.5	16.2	NA	NA
Federal Energy Administration				
Deregulation	19.5	20.6	NA	NA
Continued Regulation	19.5	16.3	NA	NA

Source: "A Comparison of Estimates of Additional Natural Gas Production from Deregulation of New Gas Prices." American Gas Association Energy Analysis, May 27, 1977.

TABLE 3-2. Estimated Gaseous Fuel Supply Schedule,
Projected to the Year 2000 (Tcf)

<u>Year</u>	<u>Domestic Supply</u>			<u>Gas Imports</u>		<u>Total Gas Supply</u>
	<u>Lower 48 Natural Gas</u>	<u>Alaskan Natural Gas</u>	<u>Synthetic Gas</u>	<u>Pipeline Imports</u>	<u>LNG</u>	
1980	18.9	-	.1	.8	.3	20.1
1985	16.7	1.5	.5	.7	.6	20.0
2000	13.6	2.9	4.7	1.0	1.5	23.7

Source: Walter G. Dupree, Jr. and John S. Corsentino, United States Energy through the Year 2000. (Revised), Bureau of Mines, U.S. Dept. of Interior, December 1975.

3.2 NATURAL GAS SYSTEM DESCRIPTION

Natural gas is generally found with oil in the pore spaces of oil-bearing sands or rock. The gas may be dissolved within the crude oil or may be entrapped separately in a geological structure known as a gas cap. About half the current supply of natural gas is produced from oil wells, and must undergo field treatment to separate the gas from the oil. Most of this gas also contains substantial amounts of water vapor. This must be removed at dehydration plants because the water can react with the gas to form hydrate crystals, which may accumulate and partially or completely block pipeline systems.

Figure 3-1 presents a schematic diagram of the natural gas transportation system. After separation and dehydration, the gas travels through field gathering lines to a natural gas processing plant, which is designed to recover certain gaseous and liquefiable hydrocarbons (natural gas liquids) from the gas stream. A typical plant removes 40% ethane (as a gas), 95% propane, 100% butane and other heavier hydrocarbons. Before the gas enters transmission lines, hydrogen sulfide and carbon dioxide must also be removed because of the extremely corrosive natures of these acid gases⁽⁹⁾ (see Section 5.1). Natural gas can also enter the transmission lines as gas imported from Canada and Mexico, gas from SNG and LNG plants, or from underground storage facilities. Distribution systems radiate from transmission line terminals to supply individual consumers.

At the end of 1975, there were almost a million miles of natural gas gathering, transmission and distribution pipelines in the U.S., powered by compressors rated at over 12 million horsepower. Table 3-3 indicates the growth in the U.S. pipeline system since 1955 and Table 3-4 shows the corresponding growth in compressor capacity. A geographical breakdown of 1975 pipeline mileage is provided in Table 3-5. From 1970 to 1975, the total pipeline mileage increased at an annual rate of only 1.4 percent. Most of this growth was for distribution pipelines, which increased at an annual rate of 1.7 percent, compared to 0.8 percent for transmission pipelines and 0.7 percent for gathering lines.

FIGURE 3-1. Natural Gas Transportation System

TABLE 3-3. Gas Utility Industry Pipeline Mileage by Type, 1950 to 1975^(a) (in thousands of miles)

Year	Total	Field and Gathering	Transmission Pipeline ^(b)	Distribution Main
1950	387.5	32.8	113.1	241.6
1951	406.6	34.6	119.1	252.9
1952	425.3	38.4	123.4	263.5
1953	446.6	41.5	130.4	274.5
1954	470.5	43.8	139.0	287.7
1955	496.7	45.7	145.9	305.1
1956	525.2	47.6	153.8	323.8
1957	548.8	50.0	160.1	338.7
1958	571.5	52.0	165.4	354.1
1959	599.8	54.1	174.3	371.4
1960	630.9	55.8	183.7	391.4
1961	659.0	56.7	191.9	410.4
1962	683.2	58.7	196.4	428.1
1963	709.9	60.7	200.9	448.3
1964	736.2	61.0	205.4	469.8
1965	767.5	61.7	211.3	494.5
1966	799.6	63.0	217.0	519.6
1967	828.3	63.7	225.4	539.2
1968	861.6	64.4	234.5	562.7
1969	891.6	64.9	248.1	578.6
1970	913.3	66.3	252.2	594.8
1971	931.4	66.2	254.8	610.4
1972	948.1	66.9	258.1	623.1
1973	962.9	65.9	263.1	633.8
1974	974.1	66.4	262.2	645.6
1975	980.0	68.5	262.6	648.9
1975 Steel	879.4	68.4	260.9	550.1
Plastic ^(c)	35.6	0.0	0.0	35.6
Other	65.0	0.1	1.7	63.2

(a) Includes data for Hawaii subsequent to 1959 and for Alaska subsequent to 1960; excludes service pipe. Data not adjusted to common diameter equivalent. Mileage shown as of end of each year.

(b) Includes 3.6 thousand miles of Underground Storage pipe in 1971, 3.3 thousand in 1972, 3.4 thousand miles in 1973, 4.9 thousand miles in 1974, and 5.0 thousand miles in 1975, some of which was formerly included in Field and Gathering pipe.

(c) Includes fiberglass.

Source: AGA Gas Facts, 1975.

TABLE 3-4. Gas Utility Industry Installed Compressor Capacity, 1955 to 1975 (in thousands of horse-power)

Year	Total	Transmission
1955	5,517	4,350
1956	6,011	4,838
1957	6,633	5,412
1958	6,996	5,612
1959	7,504	6,046
1960	7,843	6,359
1961	8,169	6,696
1962	8,609	7,064
1963	8,818	7,261
1964	9,309	7,546
1965	9,708	7,736
1966	10,242	8,132
1967	10,746	8,596
1968	11,438	9,146
1969	12,742	9,375
1970	13,150	9,692
1971	14,142	10,763
1972	14,506	10,976
1973	14,858	11,272 ^(a)
1974	15,181	11,883 ^(a)
1975	15,413	12,069 ^(a)

(a) Not comparable to previous years due to reclassification.

Source: AGA Gas Facts, 1975.

TABLE 3-5. Gas Utility Industry Pipeline Mileage by Type and by State, 1975^(a)

Division and State	Total	Field and Gathering	Transmission Pipeline ^(b)	Distribution Main
United States	980,044	68,514	262,591	648,939
New England	26,733	0	1,597	25,136
Connecticut	5,991	0	486	5,505
Maine	461	0	80	381
Massachusetts	16,452	0	789	15,663
New Hampshire	1,093	0	129	964
Rhode Island	2,401	0	53	2,348
Vermont	335	0	60	275
Middle Atlantic	113,993	6,131	17,299	90,563
New Jersey	22,077	0	1,309	20,768
New York	40,535	171	4,208	36,156
Pennsylvania	51,381	5,960	11,782	33,639
East North Central	190,172	4,095	35,818	150,259
Illinois	50,252	110	9,990	40,152
Indiana	27,267	268	5,925	21,074
Michigan	40,203	192	6,514	33,497
Ohio	51,505	3,525	10,223	37,757
Wisconsin	20,945	0	3,166	17,779
West North Central	106,522	7,340	39,439	59,743
Iowa	17,273	16	6,187	11,070
Kansas	34,280	7,253	15,629	11,398
Minnesota	15,652	0	3,985	11,667
Missouri	20,897	30	4,138	16,729
Nebraska	13,333	24	7,445	5,864
North Dakota	2,533	17	1,113	1,403
South Dakota	2,554	0	942	1,612
South Atlantic	100,310	8,526	21,906	69,878
Delaware	1,322	0	228	1,094
District of Columbia	1,163	0	23	1,140
Florida	12,914	0	2,952	9,962
Georgia	22,679	11	4,959	17,709
Maryland	8,534	27	728	7,779
North Carolina	11,100	0	2,291	8,809
South Carolina	9,667	0	2,315	7,352
Virginia	10,944	69	2,386	8,489
West Virginia	21,987	8,419	6,024	7,544
East South Central	70,345	3,731	26,670	39,944
Alabama	17,832	20	5,326	12,486
Kentucky	19,316	3,535	6,953	9,328
Mississippi	17,056	176	9,257	7,623
Tennessee	15,641	0	5,134	10,507
West South Central	195,374	24,175	82,659	88,540
Arkansas	17,474	806	6,660	10,008
Louisiana	39,114	2,355	21,611	15,148
Oklahoma	32,798	8,365	11,020	13,413
Texas	105,988	12,649	43,368	49,971
Mountain	33,056	13,701	26,375	42,980
Arizona	15,197	2	5,047	10,148
Colorado	19,064	1,886	6,118	11,060
Idaho	3,785	0	1,312	2,473
Montana	7,435	1,700	2,915	2,820
Nevada	2,945	0	1,293	1,652
New Mexico	21,657	8,332	5,892	7,433
Utah	6,577	464	901	5,212
Wyoming	6,396	1,317	2,897	2,182
Pacific	93,539	815	10,828	81,896
Alaska	868	0	115	753
California	72,493	815	7,830	63,848
Hawaii	581	0	0	581
Oregon	8,838	0	1,163	7,675
Washington	10,759	0	1,720	9,039

(a) Excludes service pipe. Data not adjusted to common diameter equivalent. Mileage shown as of end of year.

(b) Includes 4,983 miles of underground storage pipe.

Source: AGA Gas Facts, 1975.

These growth rates reflect the impact of natural gas shortages on transmission companies. There is now a significant amount of unused transmission capacity in existing pipelines. Interstate pipelines as a group were forced to curtail gas deliveries by 20 percent during the past year. An actual decline in the number of active miles of natural gas transmission lines was experienced for the first time in 1974, the same year in which production first declined.⁽³⁾

Early pipelines were built out of cast iron and copper, as well as steel as indicated in Table 3-6. However, steel and plastic pipe are now the predominant material for gas pipelines. These materials are more resistant to corrosion and breakage than the brittle cast-iron pipes. In 1975, 5,367 miles of plastic distribution pipeline were installed, nearly equal to the 5,994 miles of steel distribution pipe installed in the same period. Gathering and transmission lines are more commonly built with steel.

TABLE 3-6. Steel and Other Materials Used by the Gas Utility Industry, 1950 to 1974^(a)

Type of Material	1950	1956	1960	1964	1968	1972	1974
Steel, Total (10 ³ tons)	2,608	1,465	2,238	1,449	2,138	877	489
Pipe, Total	2,505	1,451	2,227	1,446	2,132	876	482
Pipe under 6"	276	360	339	367	340	214	105
Pipe 6" to 14"	506	425	434	375	319	275	217
Pipe 16" to 22"	(b)	(b)	29	177	179	188	97
Pipe 24" and over	1,723	666	1,225	527	1,294	198	63
Other Steel	103	14	11	3	6	1	7
Cast Iron (10 ³ tons)	96	128	35	19	11	1	(e)
Copper (tons)	2,979	1,460	1,125	3,626	2,863	1,464	653
Aluminum (tons)	89	256	34	31	138	20	30
Plastic Pipe (tons) ^(c)	(d)	(d)	(d)	848	3,728	8,790	11,328

(a) Includes usage of transmission companies, but excludes requirements for natural gas production facilities.

(b) Included in Pipe 24" and over.

(c) Tonnage of companies that installed about 2/3 total plastic distribution pipe mileage.

(d) Not available.

(e) Less than 500 tons.

Source: AGA Gas Facts, 1975.

Pipeline construction in recent years has been decreasing, particularly for interstate pipeline companies, which are regulated by the FERC and subject to price controls. The reduced construction can be related to the leveling-off in gas production and the slowdown in development of new fields. Table 3-7 compares pipeline construction for these regulated companies for fiscal years 1971 and 1975. Since 1972, pipeline construction has been at too low a level for valid statistical cost comparisons. However, trends seem to indicate an annual growth in pipeline cost of about 2 percent.

Future pipeline construction will concentrate on the maintenance and replacement of older lines, although there will be some new projects. Recent gas field development has taken place offshore and in Alaska. Pipeline construction is expected to expand in these areas.

Natural gas pipeline companies are not common carriers and they generally own the gas transported through their lines. Gas is purchased from the oil companies which produce it and sold to local utilities which distribute it to consumers.

TABLE 3-7. New Construction by FPC-Regulated Pipeline Companies (Fiscal Years Ending June 30)

Fiscal Year	Type	Miles	Pipeline		Compressor Horsepower	Compressor		Total	
			Cost (\$000)	Cost/Mile (\$000)		Cost (\$000)	Cost/Thousand Horsepower (\$000)	Cost (\$000)	Cost/Mile (\$000)
<u>1971</u>	Onshore Transmission	4,089	710,809	173.8	579,16	160,524	277.2	871,333	213.1
	Onshore Gathering and Distribution	697	23,959	34.4	64,180	24,003	374.0	47,962	68.8
	Offshore	<u>310</u>	<u>81,225</u>	<u>262.0</u>	--	--	--	<u>81,225</u>	<u>262.0</u>
	Total	5,096	815,993	160.1	643,326	184,527	286.8	1,000,520	196.3
<u>1975</u>	Onshore Transmission	1,137	183,821	161.7	202,763	76,168	375.7	259,989	228.7
	Onshore Gathering and Distribution	474	29,988	63.3	73,780	29,258	396.6	59,246	125.0
	Offshore	<u>131</u>	<u>40,714</u>	<u>310.8</u>	<u>23,000</u>	<u>12,931</u>	<u>562.2</u>	<u>53,645</u>	<u>409.5</u>
	Total	1,742	254,523	146.1	299,543	118,357	395.1	372,880	214.1

Source: FPC Staff Report: Cost of Pipeline and Compressor Station Construction Under Non-Budget Pipeline Certificate Authorizations as Reported by Pipeline Companies in Fiscal Year 1975, September 1975.

The recent trend in decreasing supplies has prompted many natural gas pipelines to diversify their investments. As of 1975, seven interstate pipeline companies were owned fully by companies engaged in natural gas production. Almost 50 other companies own some gas producing facilities. Pipeline companies are also involved in a number of other gas-related enterprises, such as compressor, fertilizer, and petrochemical manufacturing.⁽³⁾

3.2.1 Alaskan Pipeline

The largest planned pipeline expansion is a system to transport Alaskan gas to the contiguous states. Prudhoe Bay gas, which was discovered with the oil in 1968, is needed to augment dwindling natural gas supplies in the lower 48 states. The field's usable reserves are estimated at about 26 Tcf; experts estimate that Alaska's North Slope probably contains another 25 Tcf as yet undiscovered.⁽¹⁰⁾

The Alaska Highway Pipeline Project, expected to cost \$10 billion (with projected cost overruns of 25 percent)⁽¹¹⁾, will be the most expensive privately funded construction project in history.⁽¹⁰⁾ The 4,800 mile system, extending from Prudhoe Bay through Canada to the U.S., is initially planned to deliver 2.6 billion cubic feet (Bcf) of gas per day, about 5 percent of the U.S. current daily needs. The line could be expanded to carry up to 3.2 Bcf daily as additional reserves are brought onstream.⁽¹²⁾ The system is expected to be completed and ready for delivering gas to consumers by 1983.⁽¹³⁾

The planned system will actually consist of four distinct projects with separate owners. The line, which will probably be buried, will follow the route of the oil pipeline and the Alaskan Highway, avoiding unknown and undisturbed territory.⁽¹⁰⁾

The 731-mile long, 48-inch dia. Alaskan segment of the line will be built by a subsidiary of Northwest Energy, a gas-transmission company based in Salt Lake City.⁽¹⁰⁾ This line will stretch from Prudhoe Bay south to near Fairbanks, Alaska, and then east along the Alcan highway route to the Alaska-Yukon Territory border.⁽¹⁴⁾ Because of the difficult terrain and environment, this segment is expected to cost \$3.3 billion.⁽¹⁰⁾ The plan

has been given all-but-final approval by various U.S. regulatory agencies, the Congress and the President.⁽¹⁴⁾

The Canadian segment, 2,200 miles long, traverses the southwest corner of the Yukon, a corner of British Columbia and goes south across Alberta; the pipeline divides north of Calgary, Canada. It will be built at an estimated cost of \$4.4 billion by Foothills Pipelines (Yukon) Ltd., a Canadian holding company jointly owned by Alberta Gas Trunk Line Co. and Westcoast Transmission Co.⁽¹⁰⁾ The details and approvals on this segment of the line are not yet finalized. Actual construction in Alaska and Canada is projected to begin late in 1979.⁽¹⁴⁾

From Canada, the pipeline will branch into the U.S. The 911-mile long, 36-in. dia. western leg will travel from Kingsgate, B.C., to the San Francisco area and will be built by Pacific Gas and Electric Co. The 1,117-mile long, 42-in. dia. eastern leg of the line from Monchy, Alberta, to Dwight, Illinois, will be built by Northern Border Pipeline Co., a consortium of six U.S. gas transmission companies.⁽¹⁴⁾ The combined cost of these two segments of the line is estimated to be \$2.3 billion.⁽¹⁰⁾ Construction of these lines could begin late in 1978 if regulatory agencies approve the projects.⁽¹⁴⁾

The southern pipelines of the system will be built first, so that surplus natural gas in Alberta can be shipped to the U.S. The Canadian gas could begin flowing by late 1979 or early 1980, three years ahead of Alaskan gas. When the entire system is completed, Canadian gas would be repaid from Prudhoe Bay supplies.⁽¹⁰⁾

Some unresolved questions exist regarding the pipeline system. The gas and oil pipelines will run adjacent to each other for about 400 miles. The state of Alaska wants the lines kept close together to minimize environmental damage. Alyeska Pipeline Service Company, builder and owner of the existing oil pipeline, wants the two pipelines far enough apart so the oil line cannot be damaged by the blasting for the gas line trench. Blasting tests are being conducted to determine a safe separation distance.⁽¹⁰⁾

Frost heave, the freezing and swelling action of moist soil, is another design worry. Project engineers plan to start an \$8 million experiment near

Fairbanks to see whether frost heave can be controlled using deeper burial, insulation and special materials to fill the pipeline trench.⁽¹⁰⁾ Other preconstruction research will include pipe-burst tests,^(a) studies of erosion control and hydrological requirements, and wildlife studies.⁽¹³⁾

3.2.2 Operating Costs, Employment and Energy Requirements

In 1975, the investor-owned gas utility industry incurred \$2.3 billion in gas transmission and distribution operating and maintenance expenses, as shown in Table 3-8. These expenses average \$0.11 per Mcf of gas transported, or about 8.9 percent of the average delivered price of natural gas in 1975. In addition to operating and maintenance costs, the gas industry invested \$20.5 billion in transmission and \$19.2 billion in distribution facilities in 1975, according to the AGA. These investments represented 79% of the total gas industry plant costs. Total transmission and distribution plant costs in 1975 were valued at \$1.97 per Mcf of marketed gas.

TABLE 3-8. Transportation Operating Expenses of Investor-Owned Gas Utilities in 1975^(a) (millions of dollars)

	<u>Operation</u>	<u>Maintenance</u>	<u>Total</u>
Transmission	734	178	912
Distribution	633	397	1,030
Total Transportation	1,367	575	1,942
Total Operating Cost ^(b)	22,254	703	22,957
Transportation as Percent of Total Operating Cost	6.1	81.8	8.5

(a) Investor-owned gas utilities represent approximately 77% of the total capital base of the entire industry.

(b) Total operating cost includes \$18,715 million operating and \$73 million maintenance for the purchase and production of natural gas.

Source: AGA Gas Facts, 1975.

(a) The burst test will involve two sections of 48-in. dia. pipe pressured to 1260 and 1680 psi and a third section of 54-in. dia. pipe pressured to 1120 psi.

Employment in the natural gas industry has historically been very stable. Table 3-9 presents the employment and productivity trends of the gas utility industry. The industry has been able to significantly increase capacity per employee by computer control of facilities and the use of larger capacity pipelines. However, since 1971, the decrease in gas sales has reversed this trend of higher productivity.

The energy requirements of natural gas pipelines are not excessive. In general, 3 to 5 percent of the natural gas carried is consumed in the compressors operating the pipeline.⁽³⁾

TABLE 3-9. Gas Utility Industry Employment Trends

<u>Year</u>	<u>Average Number of Employees (Thousands)</u>	<u>Millions of Cubic Feet of Gas Produced per Employee</u>	<u>Total Payroll (Thousands of Dollars)</u>	<u>Payroll per Thousand Cubic Feet of Marketed Production (\$)</u>
1950	176.4	35.6	622,101	9.9
1955	193.5	48.6	904,103	9.6
1960	206.4	61.9	1,214,565	9.5
1965	205.7	78.0	1,480,397	9.2
1970	211.7	103.5	2,021,197	9.2
1971	213.7	105.3	2,142,892	9.5
1972	215.4	104.6	2,321,932	10.3
1973	215.2	105.2	2,449,075	10.8
1974	213.4	101.2	2,606,903	12.1
1975	207.6	96.9	2,817,150	14.0

Source: AGA Gas Facts, 1975.

3.3 SAFETY EXPERIENCE AND ENVIRONMENTAL IMPACTS

Natural gas is an explosive when mixed with air (in the range of 85 to 95 percent air to 5 to 15 percent methane gas).⁽⁹⁾ The transport of large, highly-pressurized quantities of natural gas near or through populated areas in a steel pipe with wall thicknesses of 0.1 to 0.5 inches has the potential of catastrophic impact under accident and failure conditions. It is this risk, rather than actual experience with pipeline ruptures, which led to

the enactment of the Natural Gas Pipeline Safety Act of 1968, to be enforced by the Department of Transportation (DOT).

The DOT prescribes safety practices and operating procedures for the gas industry, including those for pipeline corrosion protection and welding.⁽³⁾ Reports on pipeline failures and leaks and accident casualties are required by the Office of Pipeline Safety Operations (OPSO) in DOT. Safety regulations are discussed further in Subsection 3.4.

A summary of gas pipeline accidents and casualties by cause is given in Table 3-10 for the year 1975; Table 3-11 provides a comparison of accident data since 1970, when the OPSO first established accident report requirements. The number of reported accidents can be viewed in perspective if compared to the U.S. pipeline mileage. There were 1.19 accidents per 1,000 miles of gathering and transmission line and 1.51 accidents per 1,000 miles of distribution pipeline.

TABLE 3-10. Accidents and Casualties Reported by Gas System Operators During 1975

	Total Number of Failures	Fatalities		Injuries	
		Employees	Non- Employees	Employees	Non- Employees
<u>Distribution</u>					
Total	979	0	8	29	191
Subtotal by cause:					
Corrosion	94	0	1	6	23
Damage by outside forces	744	0	5	7	119
Construction defect or material failure	78	0	0	1	25
Other causes	63	0	2	15	24
<u>Transmission and Gathering</u>					
Total	394	5	1	8	9
Subtotal by cause:					
Corrosion	44	3	1	2	4
Damage by outside forces	237	0	0	0	5
Construction defect or material failure	88	1	0	5	0
Other causes	25	1	0	1	0
Gas Industry Totals	1373	5	9	37	200

Source: Eighth Annual Report on the Administration of the Natural Gas Pipeline Safety Act of 1968, DOT, 1976, (Reference 21).

**TABLE 3-11. Summary of Gas Pipeline Accidents and Casualties
Reported During Years 1970 to 1975**

Calendar Year	Number of Failures	Distribution				Number of Failures	Transmission and Gathering			
		Fatalities		Injuries			Fatalities		Injuries	
		Employees	Non- Employees	Employees	Non- Employees		Employees	Non- Employees	Employees	Non- Employees
1970	676	1	20	32	170	343	1	0	8	8
1971	875	6	36	36	329	410	2	1	14	10
1972	884	2	26	32	262	409	3	3	23	13
1973	893	1	32	48	285	471	1	1	3	16
1974 ^(a)	1017	1	19	31	283	460	1	3	7	13
1975 ^(a)	979	0	8	29	191	394	5	1	8	9

(a) Includes data from telephone reports to the Office of Pipeline Safety Operations (OPSO) reported pursuant to Section 191.5. Data from telephone reports were not included in accident/casualty data for years 1970-1973.

Source: Eighth Annual Report on the Administration of the Natural Gas Pipeline Safety Act of 1968, DOT, 1976.

The natural gas industry is concerned with the safety of transporting gas and is funding research to solve safety-related problems. The Gas Research Institute (GRI) has been formed to conduct research on the environmental effects and safety of natural gas. Table 3-12 summarizes GRI-proposed research and development program costs for the period 1977 to 1982. Research on safety problems is primarily directed at the prevention of hazardous conditions and the detection of these conditions before an accident occurs.

**TABLE 3-12. GRI-Proposed Natural Gas Transmission and Distribution
R&D Program Costs (in thousands of dollars)**

	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
Onshore transmission	1481	1450	1925	2235	2700
Offshore transmission	385	300	500	1000	1500
Arctic transmission	--	80	175	500	750
Distribution	<u>485</u>	<u>1750</u>	<u>2035</u>	<u>2330</u>	<u>2330</u>
Total	2351	3580	4635	6065	7250

Source: First Five Year R&D Plan and 1977 R&D Program, Gas Research Institute, March 7, 1977.

The gas industry is heavily involved in improving materials and procedures to prevent pipeline damage (see Section 5). Pipeline materials, welding techniques and cathodic protection against pipeline corrosion have received a great deal of attention. Much of the current effort focuses on materials suitable for use in arctic and undersea pipelines, which are subjected to stresses quite different from those affecting pipelines on land. Public relations programs to make farmers and construction contractors aware of the danger of digging without checking with the gas company for pipeline locations are also a major part of industry safety programs.

The gas industry is developing improved leak detection methods, such as acoustic detectors which "hear" leaks. Pipeline crews regularly fly over transmission lines or patrol lines on foot to detect pipeline breakages. Distribution companies add chemicals to natural gas to give it an odor; this helps in the detection of gas leaks.

The transportation of natural gas does not have a significant effect on air or water quality, since most of the transmission, distribution and gathering lines in the U.S. are buried underground. However, the initial construction of a pipeline may have severe local impacts on the environment. The land must be cleared for equipment access, the pipeline trench must be excavated and, after laying the pipeline, the fill dirt is spread and compacted.⁽³⁾ Environmental studies and tests are currently underway to minimize the impact of the construction of the Alaskan gas pipeline.

3.4 GOVERNMENT POLICY AND REGULATIONS

The Natural Gas Act of 1938 gave the Federal Power Commission (FPC) regulatory authority over the interstate natural gas industry. The FPC did not, however, have any economic control over intrastate transmission and distribution utilities. The intrastate gas market is controlled by state public utility commissions, with the exception of municipally-owned utilities which are exempt from regulation in some states.

The creation of the Department of Energy, in October 1977, replaced the FPC with the Federal Energy Regulatory Commission (FERC). FERC and the

Economic Regulatory Administration (ERA) now control most of the economics and allocation programs for natural gas in interstate commerce.

The FERC has the responsibility for:

- issuing and enforcing certificates for the construction, extension or operation of natural gas transportation and storage facilities,
- issuing certificates authorizing the sale of natural gas for resale purposes,
- investigating and establishing the rates and charges for natural gas transported or sold for resale in interstate commerce, including curtailments of services during gas shortages,
- approving interstate pipeline curtailments,
- establishing and enforcing well-head natural gas prices (the price before transportation costs), and
- regulating power/gas mergers and security acquisitions.

The FERC does not, however, have jurisdiction over gas distribution.

The ERA is in charge of:

- establishing curtailment priorities for and authorizing the import or export of natural gas,
- establishing emergency interconnections between pipelines, and
- developing standby and emergency programs for energy materials.

Safety regulation of natural gas pipelines was established by the Natural Gas Pipeline Safety Act of 1968 and is the responsibility of the OPSO. Unlike economic regulations, safety regulations apply to both inter- and intrastate natural gas pipelines. However, the OPSO does allow state agencies with approved safety programs to maintain responsibility for their intrastate transmission and distribution lines. In some cases, state agencies may also participate jointly with the OPSO in regulating the safety aspects of interstate pipelines.

The DOT, in 1978, granted \$2.4 million to assist states in strengthening their gas pipeline safety programs. The allocation between participating states was based on the estimated cost for each state's natural gas pipeline

safety activities during 1978. The funds will be used for personnel training, equipment and other related safety costs. The amount allocated was \$100,000 more than that granted in 1977. Only Texas, Oklahoma, Alaska, South Carolina, New Mexico and Florida did not apply for Federal financial assistance for safety programs in 1978.

The OPSO rules are contained in the Code of Federal Regulations, Title 49, Part 192, "Minimum Federal Safety Standards for Gas Lines." The regulations cover pipeline materials to be used, the design of the pipe and pipeline components, such as valves, fittings and compressor stations, the welding and joining of pipe sections and general construction standards for transmission lines and mains. Corrosion control, both external and internal to the pipeline, is required, and pipelines must conform to certain pressure test requirements. Inspection guidelines are outlined in the regulations as well as required operating and maintenance procedures to ensure the safe operation of natural gas lines. The OPSO requires notification of all gas leaks and annual reports on pipeline safety matters from natural gas pipeline companies, as discussed in Subsection 3.3.

3.5 NATURAL GAS STORAGE FACILITIES

Almost all natural gas is stored underground. At the end of 1975, underground storage reservoirs in the United States had a total capacity of 6.6 Tcf. Above-ground storage (LNG facilities, including satellite plants) represented only 70.3 Bcf, or about one percent of the total capacity. Table 3-13 summarizes U.S. natural gas storage capacity. Michigan, Pennsylvania, Illinois, California, West Virginia and Ohio together account for over 67 percent of the U.S. underground storage capacity; another 12 percent is located in the natural gas-producing states of Louisiana, Texas and Oklahoma.

Industry, with the encouragement of the Federal government, is increasing the development rate of storage capacity. Increased storage of gas will facilitate deliveries during the winter months, when demand for natural gas supplies reaches a peak level. Table 3-14 shows the recent trend in storage capacities. At the end of 1975, the maximum natural gas sendout capacity

TABLE 3-13. U.S. Natural Gas Storage Capacity
(December 31, 1975)

<u>Type of Storage</u>	<u>Number of Facilities</u>	<u>Capacity (Bcf)</u>
Underground	376	6644
Aquifer	52	1459
Other ^(a)	324	5185
LNG	96	70
Complete plants	46	50
Satellite plants	47	5
Import terminals	3	15
TOTAL	472	6714

(a) 296 reservoirs originally containing dry gas,
16 reservoirs originally containing oil and gas,
7 reservoirs originally containing oil, 4 reser-
voirs originally containing salt, and 1 reservoir
originally containing coal.

Source: AGA Gas Facts, 1975.

TABLE 3-14. Trends in U.S. Underground
Gas Storage Capacity (Bcf)

<u>Year</u>	<u>Underground Gas Storage</u>	<u>LNG</u>	<u>Propane-Air and Other</u>	<u>Total</u>
1972	39.5	4.5	4.0	48.0
1973	42.0	5.5	4.5	52.0
1974	45.0	7.0	5.0	57.0
1975	48.5	6.5	4.5	59.5
1976	49.8	7.2	5.0	62.0
1977	51.2	7.6	5.4	64.2

Source: Reference 15.

from storage was 38.8 Bcf, 30.6 Bcf of which came from underground storage. Peak-shaving or supplemental supplies for the winter of 1977-1978 were over 64.21 Bcf per day total capacity, including 51.23 Bcf from underground gas storage, 7.63 Bcf from LNG peaksaving and satellite plants, 4.93 Bcf from propane-air plants and 0.42 Bcf from other sources, including SNG plants.⁽¹⁵⁾

As of November 1, 1977, there were 393 underground fields belonging to 87 companies, of which 367 fields were active and 26 were under development. Expenditures for 1978 on underground storage are expected to exceed \$252 million; total investment in underground storage plant is now over \$2.95 billion.⁽¹⁵⁾

The extensive system of natural gas storage fields has necessitated some construction of transmission and distribution lines. However, the location of storage facilities near consumption centers has alleviated some of the need for increased transmission line capacity to serve the peak use periods.

3.6 NATURAL GAS FLOW PATTERNS

Domestic natural gas production for 1974 was nearly 22 Tcf; 16 Tcf, or 73 percent of this amount, was produced from wells in Texas and Louisiana. Oklahoma, Kansas and New Mexico contributed 3.8 Tcf, or 17 percent. These five states together produce 91 percent of the marketed production of natural gas in the United States.⁽³⁾

However, much of the gas produced in the U.S. is consumed by intrastate markets. The five states mentioned above consume about 30 percent of the total domestic natural gas production. Another 30 percent of gas consumption is concentrated in the North Central and Middle Atlantic states and in California. The remaining 40 percent is consumed primarily in the northern Midwest and the Southeast, which receive interstate natural gas. Alaska, Hawaii and Vermont are not part of the U.S. natural gas supply network.⁽³⁾ Figure 3-2 graphically shows the 1974 interstate movements of natural gas. The appendix presents a natural gas flow analysis performed by the Federal Power Commission in 1976.

FIGURE 3-2. Natural Gas Transported in 1974 by FPC Regulated Pipelines

Major transmission lines to the Midwest are about 1,000 to 1,500 miles long. Intrastate movements amount to almost one-third of domestic natural gas transportation; a large proportion of natural gas is thus transported less than 500 miles. Natural gas is also received from Mexican and Canadian pipelines, as well as from LNG facilities; this gas is usually transported to nearby markets.

Natural gas sales and movements are highly seasonal, as shown in Table 3-15, and it has been necessary for the industry to maintain a transportation capacity in excess of that which would be required for the average demand. In 1975, the peak demand month, January, required the delivery of 85 percent more natural gas than in the low month, July. The data presented in Table 3-15 represent deliveries to end users.

TABLE 3-15. 1975 Gas Utility Industry Sales
by Month (in trillions of Btu)

	<u>Volume (a)</u>	<u>Index (b)</u>
January	1709.5	1.38
February	1633.6	1.32
March	1588.4	1.28
April	1453.3	1.17
May	1120.8	.90
June	944.8	.76
July	924.7	.75
August	934.8	.75
September	935.4	.76
October	1009.2	.81
November	1102.8	.89
December	1503.6	1.21

(a) One thousand cubic feet of natural gas average 1,024,000 Btu.

(b) 1.0 is used as Average Monthly Index.

Source: AGA Gas Facts, 1975.

The variation in natural gas demand patterns occurs because most residential and commercial customers use the fuel for heating requirements. Less gas is required during the warm summer months for heating purposes. Industrial consumers use natural gas for manufacturing processes rather than for heating; these sales thus do not reflect a significant seasonal variation. However, industrial users have been improving operating efficiencies and converting to other fuels. Industrial consumption of natural gas has decreased from 53 percent of total consumption in 1970 to 46 percent in 1975. As the steady load from industrial users diminishes, the seasonal variations in demand from residential and commercial consumers will become proportionally larger. This change in consumption pattern may impact the industry's ability to deliver supplies (see Section 4.2).

4.0 POTENTIAL PROBLEM IDENTIFICATION, EVALUATION AND RECOMMENDATIONS

The identification and evaluation of potential problems in natural gas transportation were based on the system characterization in Section 3.0, with emphasis on potential safety and environmental problems that should be considered in DECT programs.

The diversity of potential problems affecting energy material transportation has suggested the use of the concern summary format for presenting results of this study. In Sections 4 and 5 of this report, the concern summaries are independent subsections, providing a description of potential problems which warrant attention. These summaries have the following standard format:

- concern
- basis
- related work
- appraisal
- recommended action
- priority

A major objective of this approach is to achieve a concise appreciation of specific potential problems and a coherent basis for recommending action and priorities. The concern statement describes specific potential problems and consequences which may impact the future development of natural gas transportation. The basis for the concern includes the identification of situations or trends causing anticipated problems. Ongoing or planned efforts which investigate solutions to these problems are acknowledged, when possible, in the summary of related work. The appraisal provides an overall perspective on the concern as a basis for recommending appropriate action. Recommendations are made to address anticipated problems which do not appear to be adequately covered by efforts in other programs. The concern summary includes judgements of priority, appropriate level of manpower and timing of recommended action for each potential problem.

In view of the extensive volume of research, development and engineering that is currently supported by industry and government to develop gas transportation systems, only three general areas of concern are identified as needing significant new project effort.

The following concerns in Section 4 are judged to warrant additional attention in FY-1979 and FY-1980 programs of the DOE or other cognizant government agencies. Other concerns were identified as being under control and do not appear to warrant additional new program activities at present; these concerns are reviewed in Section 5.

4.1 TRANSPORTATION OF NEW FUEL TYPES IN EXISTING GAS PIPELINES

- CONCERN

Safety hazards may result from the transportation of new fuel types, such as high- or low-Btu gas, SNG and hydrogen, through existing natural gas pipeline systems.

- BASIS

New, alternative gaseous fuels have different compositions than that of natural gas and may cause safety problems if transported in existing natural gas pipelines as currently proposed. Low-Btu SNG, for example, may contain relatively high amounts of carbon monoxide (CO), carbon dioxide (CO₂) and water. These compounds acting together can cause internal corrosion and stress-corrosion cracking in pipelines. The effects of these chemicals on the long-term degradation of plastic pipe are unknown.

Alternative gaseous fuels also have different flammability or explosion limits important to the management of pipeline leaks. The explosion limits for natural gas (methane) range from 5 to 15 percent in air, whereas the limits for hydrogen range from 4 to 74 percent and from 12.5 to 74 percent for carbon monoxide. Gases with a high concentration of carbon monoxide can also be toxic.

- RELATED WORK

The AGA has conducted some research on the effects of high-Btu gas on stress-corrosion cracking of steel pipelines. Results have indicated that impurities (CO, CO₂ and oxygen) in this gas can cause internal cracking in normal pipeline steels. Information is also available on the corrosive potential of carbon dioxide. Research on the storage of hydrogen in pipeline materials is in progress at Sandia Laboratories and the Institute of Gas Technology (IGT) is conducting research on the transportation of hydrogen through gas transmission lines. These studies address some of the potential fracture problems associated with synthetic gas transport.

Many studies currently center on purifying synthetic gases to avoid transporting potentially corrosive materials through present pipeline systems.

- APPRAISAL

Alternative fuels are being proposed for use in current energy systems. While only a few SNG plants are in operation at this time, it is expected that the number of plants will increase during the 1980s. Safe and environmentally acceptable procedures for transporting these gases should be developed before these plants come on line. Current programs aim primarily at purifying synthetic fuels before transporting them. Additional effort appears to be needed to ensure that these new fuels are compatible with the existing gas transportation and storage network.

- RECOMMENDED ACTION

A study is needed to determine whether modifications or additional requirements are necessary so that pipeline systems may safely transport other gaseous fuels. Data on the environmental effects of releases of these new fuels should be gathered and evaluated to guide legislative action on the siting requirements of SNG plants and pipelines. Information on retrofitting existing pipeline systems, as well as the establishment of pipeline design standards, may be required for alternative gaseous fuels. DECT should be involved in aspects of this work.

- PRIORITY

Because synthetic gaseous fuels are not expected to be a significant fraction of the national supply until the late 1980s, enough lead time appears to be available to define acceptable solutions to this transportation problem. A moderate priority is therefore suggested for a one to two man-year level of effort in FY 1979 to address this concern.

4.2 CONTINGENCY SUPPLY PLANNING FOR EMERGENCY CONDITIONS

- CONCERN

Natural gas transportation systems may be inadequate to supply future regional demand under emergency conditions. Fluctuations in seasonal demand may further contribute to difficulties in delivering gas supplies.

- BASIS

There does not appear to be an overall contingency plan for rerouting natural gas supplies in the event that a major part of the system is shut down under emergency conditions. Emergencies could result from accidents, sabotage, or natural disasters. For example, gas pipelines in Louisiana transport approximately 3 Bcf of gas daily through parallel lines within a 150 ft-wide right-of-way. The repair of these lines, if extensively damaged, would require several days, resulting in severe regional energy shortages.⁽⁹⁾

The natural gas industry caters to a highly seasonal fuel demand, because a large portion of sales are for residential space heating. Fluctuations in demand are becoming more pronounced as the steady loads of industrial users are switched to alternate fuel sources. The seasonal demand differential may adversely affect the industry's ability to supply peak loads, particularly under emergency conditions.

- RELATED WORK

The Federal Energy Regulatory Commission (FERC) is examining the necessity for greater control over the purchase of intrastate gas for the interstate market in emergency situations. Subjects under investigation include stricter controls over pricing and a tighter definition of conditions that justify emergency transactions. Preliminary rules will be issued in 1978.⁽¹⁶⁾ The FERC also has an emergency program to help curtailed industrial users obtain gas while arranging for conversion to alternate fuels. The experimental policy allows industrial users to buy natural gas in the field for transportation through interstate pipelines.

The Economic Regulatory Administration (ERA) may issue new or alternative sets of natural gas curtailment priorities. A notice of inquiry is being issued, and priorities should be decided in time for the winter months of 1978-1979. The curtailment priorities set by ERA are enforced by FERC. ERA also has the responsibility for managing standby and emergency programs and for the establishment of emergency interconnections between gas pipelines. The LP Gas Federal Advisory Committee studied the supply, demand and transportation characteristics of LPG. A report was submitted to FEA on June 28, 1977 including a discussion of overseas transportation and necessary terminal facilities and suggested additions to current transportation facilities.

A task force was formed by the FEA in July 1977 to produce a Winter Energy Emergency Plan. This study will attempt to define emergency plans in the event of another severely cold winter with fuel shortages. Allocation and other Federal measures to alleviate shortages (other than rerouting) will be investigated. A handbook for state government officials, entitled "State Planning for Winter Energy Emergencies," has been compiled.

President Carter's energy policy proposes the creation of an emergency management information system to acquire the necessary data on local energy supplies and demand to respond to a natural gas shortage or other emergency.

- APPRAISAL

The network of gas utility mains and services is designed to meet maximum probable demand conditions. Gas supply planning, including pipeline and supplemental, or peakshaving, supplies, is programmed to meet the worst possible demand conditions with the best available resources.⁽¹⁷⁾

Industry is usually aware of shortfalls of gas supply in advance and knows whether pipeline deliveries will be below total requirements. A survey by the Pipeline and Gas Journal revealed that companies give first priority to meeting the peak needs of residential and commercial customers. Low priority industrial customers may get no gas service at all during the high demand winter months.⁽⁸⁾

The gas industry uses other emergency procedures besides increasing supplemental supply capacity. Companies urge interruptible customers to develop alternate fuel supplies, vigorously promote conservation programs and, where possible, maintain storage fields at or near capacity. Emergency purchases from intrastate companies and emergency interconnections between pipeline systems may also be made. During the winter of 1976-77 gas was exchanged with utilities in the Southwest, Rocky Mountain and Pacific Coast areas so that additional gas supplies could be moved eastward and northward. Gas distribution utilities also share their supplies with neighboring utilities.⁽¹⁷⁾

The transportation and delivery of natural gas to meet seasonal demands appear to be adequately addressed by the efforts of industry and regulatory agencies. However, potential delivery problems with gas and other fuel types may be encountered in emergency situations and require contingency planning on a national scale to avoid serious regional energy shortages.

- RECOMMENDED ACTION

The natural gas system should be included in a network analysis of the national energy distribution system to provide a data base for planning of energy material transportation under emergency conditions. A vulnerability

study should be performed to determine the impacts of specific emergency scenarios on each transportation mode. Possible safety and environmental effects of sudden interruptions in the gas supply should be assessed with DECT involvement.

- PRIORITY

The planning of energy material transportation under emergency conditions is a national priority requiring DOE attention, interagency effort and industrial involvement. Natural gas transportation should be considered within the scope of the comprehensive program recommended in the Petroleum transportation task report of this study.⁽¹⁸⁾ As a supporting activity the DECT should initiate a moderate priority effort, at a level of 1/2 to 1 man-year in FY 1979, to assess potentially hazardous consequences of gas supply interruptions.

4.3 POSSIBLE EFFECTS OF MAJOR NATURAL DISASTERS

- CONCERN

Major natural disasters may cause extensive damage to gas distribution systems that could result in fires and explosions in populated areas.

- BASIS

Major disasters, such as the San Francisco earthquake, have demonstrated that the biggest hazards of broken gas lines are fire and explosion. It is possible that future occurrences of earthquakes, floods and mudslides may cause gas lines to rupture near or in large urban areas, resulting in a high incidence of death and property damage. The hazard potential may be steadily increasing as both industrial development and population density expand in the vicinity of gas distribution and transmission pipelines.

- RELATED WORK

No specific research in this area is known. Current pipeline designs, however, are based on data obtained during past earthquakes, floods and landslides. The Trans-Alaska oil pipeline, for example, was designed and constructed to withstand earthquakes of the severity experienced in the Anchorage area in 1964.

- APPRAISAL

The natural gas industry has been involved for many years in improving the safety of pipeline systems. Regulations at the Federal level help to ensure the safe transportation of natural gas by pipeline, particularly in heavily populated areas. Extensive work has been done in the areas of corrosion control, leak detection and the deterioration of older pipelines, as well as in the development of preventive programs for pipeline damage by outside forces (see Section 5).

However, most of these programs aim at relatively passive levels of degradation or the prevention of damage caused by human carelessness. No programmatic effort is apparent that is designed to protect the system against extreme impacts of natural disasters. A risk assessment is needed to evaluate the probability of occurrence and potential effects of extensive pipeline rupture in areas where a sizeable population or other valuable resources reside in the vicinity of gas pipeline systems.

- RECOMMENDED ACTION

A risk assessment would be useful in projecting the potential impact of major natural disasters based on the probability of occurrence and impact on gas transportation systems which are near centers of population or valuable property. This assessment should be used to determine if new emergency shutdown and protection techniques are needed. The risk assessment should include impacts on underwater pipelines and be coordinated with the vulnerability study recommended in the previous concern summary (Subsection 4.2). This concern should be considered in future DECT program plans.

- PRIORITY

The recommended risk assessment is judged to have a moderate to low priority because of the infrequent history of major geological events which have had serious impact on gas transportation systems. A 1/2 to 1 man-year effort in FY 1979 or FY 1980 is suggested to provide an initial review of this concern.

5.0 LATENT CONCERNS

This section contains a brief account of latent concerns which, at present, do not appear to warrant additional attention in new programs. These concerns appear to be diminishing problems which are currently being resolved by industry effort or adequately addressed by ongoing programs. The DOE should remain aware of possible future changes that might increase the importance of these concerns.

5.1 PIPELINE CORROSION

- CONCERN

Pipeline corrosion can be a direct cause of pipeline failure and result in hazardous conditions.

- BASIS

Pipeline corrosion results from an electromechanical reaction which causes pitting and cracking of metal surfaces and can ultimately lead to a loss of metal surface and failure of the line.⁽¹⁹⁾ Corrosion is a major cause of natural gas distribution pipeline fatalities and injuries, representing 14 percent of the 1975 total. In the natural gas transmission industry, corrosion was responsible for 12 percent of the fatalities and injuries which occurred in 1975.⁽²⁰⁾

During the past several years, there has been a shortage of natural gas in the U.S. Many gathering pipeline companies have thus been forced to accept lower qualities of gas than would have normally been purchased to enable them to continue supplying fuel to consumers. As a result, gases containing higher volumes of liquids (such as water and hydrocarbons) and corrosive acid gases (such as carbon dioxide and hydrogen sulfide) are being transported. The increased throughput of corrosive elements in pipelines may accelerate corrosion on the internal surfaces of the line.⁽²⁰⁾

- RELATED WORK

Federal regulations on corrosion control are contained in the 49 CFR 192, Subpart I.⁽²¹⁾ Research and development by the AGA has concentrated extensively on the problem of pipeline corrosion. The OPSO in DOT is also currently involved with a survey on environmental cracking problems in gas pipelines, which may aid in defining the need for additional research effort.

A new pipeline coating system has been developed which uses a seamless, tightly bonded butyl rubber and high density polyethylene. This pipe coating is being applied at the Galveston, Texas, plant of the H.C. Price Co.'s Coating Division. Once applied, the 70 mil coating is extremely difficult to remove from the pipe surface, providing good mechanical protection against corrosion.

Du Pont has a fusion bonded pipe coating called "Flintflex", a thermosetting epoxy resin formulated for electrostatic application to clean pipe. Characteristics of the coating include cathodic disbonding resistance, abrasion and corrosion resistance, and strength and flexibility. Internal pipeline coatings are also being developed.

Union Carbide Industrial Services Co. has developed a continuous protective lining for pipelines which is highly resistant to corrosion. These companies are among the many who are developing improved pipeline coatings.

Internal pipeline corrosion can also be prevented by organic and inorganic inhibitors, chemicals which are injected into the gas stream in a pipeline. These inhibitors coat the internal surfaces of the pipeline, providing protection against corrosion of the line and thus preventing line failures and damage to gas plant equipment.⁽¹⁹⁾

The Nalco Chemical Co., in Sugar Land, Texas, has created two new inhibitor formulations. One is designed for gas streams which have little liquid content; the other is designed to help prevent corrosion in lines with a high liquid content. Both inhibitors form a film on metal surfaces and protect against corrosion of the inner surfaces of the pipeline.

Petrolite Corp.'s Tretolite Division is another company involved in the development of corrosion inhibitors. Their line of KONTOL corrosion inhibitors are stable organic compounds which will adsorb on the internal metal surface of a pipeline in the presence of water. The resultant film formed on the pipe surface is resistant to carbon dioxide, hydrogen sulfide, sand, solids and other corrosive agents.

Holosonics, Inc., has developed an ultrasonic imaging^(a) technique which detects corrosion and stress corrosion cracking of in-service pipelines. The images produced by the system present two-and-three-dimensional pictures of corrosion, pitting, or losses of material from the inner surfaces of pipeline walls. Systems which have been constructed range from a simple hand scanner for use in field operations to systems that travel inside the pipeline. Special systems have also been developed which inspect pipeline welds from the outside surfaces during construction.⁽²²⁾

A survey published in Pipeline and Gas Journal⁽²³⁾ describes some corrosion protection measures taken by the industry. In response to the Federal pipeline safety regulations, many companies have increased budgeting for corrosion control and accelerated their corrosion protection and pipeline maintenance programs.

- APPRAISAL

Pipeline companies have been concerned with the problems of pipeline corrosion for many years. Cathodic protection methods, pipeline coatings and chemical prevention mechanisms have been developed and are continually being improved. Industry is also increasing the emphasis placed upon corrosion control and pipeline maintenance programs, largely as a result of new Federal pipeline safety regulations.

(a) Ultrasonic imaging is a system that simultaneously presents multiple images of either the near or far surface of a pipeline wall.

Extensive Federal regulation exists governing corrosion control methods in gas pipelines. Specified external protective coatings and cathodic protection systems are required. Pipelines under cathodic protection must be tested at least once during each calendar year, with intervals not exceeding 15 months, to ensure that the system meets Federal specifications. The electrical components of these systems must be inspected every two months to ensure proper operation.

Procedures for detecting and correcting corrosion are also outlined in the Federal regulations. If corrosion is found to exist^(a) the pipe must be replaced. The operator of the pipeline must maintain records throughout the lifetime of the line, which show the location of cathodically protected pipeline and associated facilities. These documents must also record the results of all tests and inspections required by Federal regulations.

The requirements of Federal regulations and an active industry research and development effort seem to adequately address the corrosion problem. No additional effort is recommended.

5.2 DETERIORATION OF OLDER DISTRIBUTION SYSTEMS

- CONCERN

The potential deterioration of aging distribution systems may cause safety hazards in the older and larger urban areas.

- BASIS

Although cast-iron distribution mains have rarely been installed in the past 30 years, more than 370 million feet are still in use, primarily in urban areas where replacement costs are high. Although the cast-iron systems have, to date, performed well, the aging characteristics of the material create a potential for cracks to develop.

(a) The allowable limits of corrosion vary according to the pipeline material and use.

Cast-iron is inherently resistant to corrosion. However, it is extremely brittle, which leads to line breakage in excavation activities or by soil movement, such as frost heaves. The deposition of graphite on cast-iron systems by direct currents in the soil (in certain localities) can make the cast-iron even more brittle and susceptible to breakage. Leaks resulting from cracks in older cast-iron pipelines may lead to safety hazards, particularly in large older urban areas.

- RELATED WORK

Federal regulations on the operation and maintenance of distribution pipelines are contained in 49 CFR 192, Subparts L and M.⁽²¹⁾

The gas industry has developed techniques for repairing dried-out joints in cast-iron pipe and inserting new plastic pipe liners. Extensive replacement of pipe, particularly cast-iron, has also been performed by the industry. Partially as a result of problems in obtaining gas supplies, gas companies have been improving maintenance of current systems rather than expanding them. Much of the new construction centers on the replacement of old facilities. Distribution system maintenance expenditures in 1976 totalled \$497 million, up 9.2 percent from 1975.

- APPRAISAL

Pipeline companies, concerned with the problems of pipeline deterioration, have developed techniques to deal with embrittlement in cast-iron pipe, including external clamping of joints and internal sealing of the pipe, or insertion of steel or plastic liners. Pipeline coating techniques and corrosion control programs are being continually improved (see Section 5.1).

Federal regulations require that cast-iron service pipes not be installed under buildings. If graphite deposition is found in a cast-iron pipe, to the extent that leaks might result, the pipe must be replaced. Leak surveys must be conducted each year in principal business districts.

Each operator is required to have a procedure for continuing surveillance of its facilities to determine failures, leak history, corrosion and other unusual operating and maintenance conditions. If a segment of pipeline is found to be in unsatisfactory condition, but not immediately hazardous, the operator must initiate a program to replace or phase out the segment involved, or to reduce the operating pressure. Leak detection and reporting requirements are defined in the Federal regulations⁽²¹⁾ together with remedial and emergency operating procedures if leaks occur.

Plastic pipe accounted for more than 50 percent of all pipe used for new and replacement gas mains and services installed during 1976. The latest count indicated that 824 gas distribution utilities (out of a total of 1566) use plastic pipe in their system. In 1966, 12.0 percent of all distribution piping installed was plastic. This number has risen to 54.5 percent in 1976. It is projected that by 1977, 56 percent of all distribution piping installed will be plastic.⁽²³⁾ The problems associated with cast-iron pipes will most likely diminish as they are replaced or lined with plastic pipe in preference to other materials.

Comprehensive Federal regulations and an active industry research and development effort seem to adequately address problems relating to leakage, failure and the detection of deterioration in pipelines. Each operator is required to have a predetermined contingency plan to facilitate efficient, safe pipeline repair procedures. No additional programmatic effort is recommended.

5.3 THIRD PARTY DAMAGE TO PIPELINES

- CONCERN

Damage to buried gas pipelines, particularly from excavation work and other underground construction, continues to cause most of the pipeline failure incidents in the United States. These incidents can result in explosions or fire, service interruptions and additional maintenance and repair costs.

- BASIS

Third-party damage is the major cause of pipeline leaks and ruptures reported to the Office of Pipeline Safety Operations, DOT, under the Federal gas pipeline safety regulations.⁽²⁵⁾ From 1970 through 1975, 70.8 percent of all reported distribution incidents and 56.3 percent of all transmission incidents resulted from the action of outside forces. In 1976, third-party forces caused 55 percent of all leaks and ruptures and resulted in more than one-third of the gas pipeline-related deaths and injuries.

- RELATED WORK

A 1968 study by Battelle Columbus Laboratories⁽²⁶⁾ analyzed causes of and determined possible means of preventing external damage to pipelines. The National Transportation Safety Board (NTSB) issued a report entitled "Special Study on Prevention of Damage to Pipelines" in June 1973. A number of regions in the country, led by the local utilities, have organized and are operating "one call" services, where a contractor can obtain information on underground gas, water, sewer, telephone and electric utilities. These systems are operating in Ohio, Michigan, Texas, Connecticut and other States.

In June 1977, DOT Secretary Adams sent the "Model Underground Utility Damage Prevention" Act to the Governors of the 50 states and Puerto Rico, and the Mayor of the District of Columbia. This Act is intended to assist state legislatures in developing underground utility damage prevention legislation or in determining whether current laws can be made more effective. This model statute would facilitate programs for assuring that underground excavators and utility operators establish communications prior to excavation and take appropriate action to prevent damage to buried pipelines and other utilities. Also, it is intended that where State constitutions permit, utility location and coordination councils, one-call systems, or similar damage prevention programs could be established and made more effective by such a statute.

Federal gas pipeline safety regulations require that by January 1, 1978, line markers must be installed over each buried main and transmission line wherever necessary to identify the location of such lines and to reduce the possibility of damage or interference. However, line markers are not required in urban areas where laws for preventing interference with underground pipelines are established.

Programs for the prevention of damage to pipelines by outside forces will be evaluated by IIT Research Institute of Chicago, IL., under a contract from DOT. The study will include:

- an analysis of state and local laws directed at pipeline and utility line damage prevention,
- an evaluation of DOT proposed model statute and responses,
- a review of line-marking regulations and their effectiveness,
- a determination of the role of cooperative groups' efforts, such as underground coordinating councils, and
- an evaluation of various national group programs.

The study will also review the activities of industry, contractor, utility and labor actions, and other activities by Federal, state and local government organizations. After a review of current related research and technical programs, recommendations will be prepared for future research, regulations or other action.

- APPRAISAL

The AGA and individual pipeline companies have been formulating preventive measures for pipeline damage by outside forces for many years. Federal regulations governing the safety of transportation of natural gas by pipeline require that pipeline locations be clearly marked. Regional programs exist to inform contractors of buried utilities locations, in a further effort to minimize third-party damages to pipelines. The adequacy of current programs is being evaluated in a comprehensive study by IIT Research Institute. Although recommendations of the IIT study, when complete, may change the relative importance of this concern, at present, no new programmatic action appears to be warranted.

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APPENDIX A
ANALYSIS OF 1974 NATURAL GAS INTERSTATE FLOWS

The Federal Power Commission (FPC) has prepared an analysis of 1974 interstate gas flows in a staff report released in October 1976. The report, Natural Gas Transported in 1974 by FPC Regulated Pipelines, is based on information filed by gas utilities and assumptions by the FPC staff as to logical allocations when gas from two sources is mixed together. A summary table of natural gas movements from this FPC report is shown in Table A-1. The supply area and market area codes used for this table are given in Figures A-1 and A-2.

TABLE A-1. Natural Gas Transported in 1974 by FPC Regulated Pipelines Summary of Gas Flow Between Major Supply Areas and Detailed Market Areas (volumes in billion cubic feet)

Federal Power Commission Supply Areas	1 Appal- III.	2 Other S.W.	30 S. L.A. Onsh.	31 S. L.A. Offsh.	4 Texas G. C.	5 Permian Basin	6 Hug.- Anad.	7 Rocky Mtn.	8 Other Areas	South Alaska	Gross Imports	Total
Gas Requirements												
Committee Market Regions												
I New England												
Connecticut	0	4	24	31	9	0	0	0	0	0	0	69
Maine	0	0	0	1	0	0	0	0	0	0	0	2
Massachusetts	0	9	52	74	22	0	0	0	11	0	0	167
New Hampshire	0	0	2	5	1	0	0	0	0	0	0	9
Rhode Island	0	2	9	6	2	0	0	0	0	0	0	19
Vermont	0	0	0	0	0	0	0	0	0	0	5	5
Total Area I	0	16	88	117	35	0	0	0	11	0	5	271
II Appalachian												
Delaware	0	0	2	13	4	0	0	0	0	0	0	20
District of Columbia	2	0	13	11	2	0	0	0	0	0	0	29
Kentucky	10	12	110	93	10	0	0	0	0	0	0	236
Maryland	16	3	87	62	11	0	0	0	0	0	0	179
New Jersey	0	11	62	153	51	3	0	0	3	0	0	277
New York	70	21	161	326	94	0	0	0	0	0	6	678
Ohio	95	35	377	316	101	0	122	1	0	0	0	1,048
Pennsylvania	101	26	246	308	83	0	0	0	0	0	0	763
Virginia	10	2	58	64	15	0	0	0	0	0	0	148
West Virginia	12	2	48	34	6	0	0	0	0	0	0	102
Total Area II	316	112	1,166	1,380	377	0	122	1	0	0	6	3,481
III Southeast												
Alabama	0	33	135	99	13	0	0	0	1	0	0	280
Florida	0	7	162	14	59	0	0	0	30	0	0	272
Georgia	0	38	161	127	13	0	0	0	1	0	0	341
North Carolina	0	0	11	95	31	0	0	0	0	0	0	138
South Carolina	0	13	57	62	11	0	0	0	0	0	0	143
Tennessee	0	12	97	136	25	0	0	0	0	0	0	270
Total Area III	0	103	623	533	153	0	0	0	32	0	0	1,443
IV Great Lakes												
Illinois	0	49	125	221	269	120	380	3	0	0	25	1,193
Indiana	0	18	103	148	74	18	175	2	0	0	5	544
Michigan	0	5	215	382	55	9	137	2	0	0	35	839
Wisconsin	0	0	4	9	0	23	150	1	0	0	187	376
Total Area IV	0	72	449	760	398	170	843	7	0	0	252	2,952
V Northern Plains												
Iowa	0	9	0	0	0	125	209	5	0	0	0	348
Minnesota	0	0	0	0	0	135	159	7	0	0	24	324
Nebraska	0	1	0	0	0	57	119	29	0	0	0	197
North Dakota	0	0	0	0	0	0	0	18	0	0	6	24
South Dakota	0	0	0	0	0	9	11	11	0	0	0	32
Total Area V	0	10	0	0	0	327	497	60	0	0	30	924
VI Mid-Continent												
Kansas	0	19	0	0	0	75	365	11	0	0	0	470
Missouri	0	35	87	23	13	23	202	1	0	0	0	383
Oklahoma	0	27	0	0	5	8	42	0	0	0	0	83
Total Area VI	0	82	87	23	18	106	609	11	0	0	0	937
VII Gulf Coast												
Arkansas	0	189	10	5	8	0	43	0	0	0	0	254
Louisiana	0	83	172	75	15	0	0	0	0	0	0	345
Mississippi	0	24	112	104	10	0	0	0	0	0	0	251
Texas	0	206	1	66	281	242	78	1	0	0	0	875
Total Area VII	0	502	295	250	314	242	120	1	0	0	0	1,725
VIII Rocky Mountain												
Colorado	0	0	0	0	0	0	128	146	0	0	0	274
Montana	0	0	0	0	0	0	0	20	0	0	48	68
Utah	0	0	0	0	0	0	0	113	0	0	0	113
Wyoming	0	0	0	0	0	0	0	78	0	0	0	78
Total Area VIII	0	0	0	0	0	0	128	357	0	0	48	534
IX Pacific Southwest												
Arizona	0	0	0	0	0	131	0	61	1	0	0	193
California	0	0	0	0	0	867	56	316	0	0	344	1,583
Nevada	0	0	0	0	0	21	0	36	3	0	4	65
New Mexico	0	0	0	0	0	66	3	28	0	0	0	97
Total Area IX	0	0	0	0	0	1,085	59	441	4	0	348	1,937
X Pacific Northwest												
Idaho	0	0	0	0	0	0	0	40	0	0	9	49
Oregon	0	0	0	0	0	0	0	0	0	0	104	104
Washington	0	0	0	0	0	0	0	0	0	0	182	182
Total Area X	0	0	0	0	0	0	0	40	0	0	296	336
Gross Exports												
To Canada	0	0	10	18	1	0	10	0	0	0	281	319
To Mexico	0	0	0	0	6	4	0	0	0	0	0	9
To Japan	0	0	0	0	0	0	0	0	0	50	0	50
Total Exports	0	0	10	18	6	4	10	0	0	50	281	379
Total	317	996	2,716	3,082	1,302	1,934	2,389	920	47	50	1,265	14,918

Source: FPC Staff Report: Natural Gas Transported in 1974 by FPC Regulated Pipelines, October 1976.

FIGURE A-1. Natural Gas Supply Areas

TABLE A-2. Natural Gas Supply Area Codes

<u>Major Supply Area</u>	<u>Subareas</u>
1 Appalachian-Illinois Basin	10 Appalachian Basin North 11 Appalachian Basin South 12 Illinois Basin
2 Other Southwest	20 Mississippi-Alabama 22 Northern Louisiana 23 Texas Railroad Commission District No. 6 24 Southern Arkansas 25 Texas Railroad Commission District No. 5 26 Texas Railroad Commission District No. 9 27 Other Oklahoma 28 Northern Arkansas
3 South Louisiana	30 South Louisiana-Onshore 31 South Louisiana-Offshore
4 Texas Gulf Coast	40 Texas Railroad Commission District No. 2 Onshore 41 Texas Railroad Commission District No. 3 Onshore 42 Texas Railroad Commission District No. 4 Onshore 43 Texas - Offshore 44 Texas Railroad Commission District No. 1 (South)
5 Permian Basin	50 Texas Railroad Commission District No. 7-B 51 Texas Railroad Commission District No. 7-C 52 Texas Railroad Commission District No. 8 53 Texas Railroad Commission District No. 8-A 54 Texas Railroad Commission District No. 1 (North) 55 New Mexico-Permian Basin
6 Hugoton-Anadarko	60 Texas Railroad Commission District No. 10 61 Oklahoma Panhandle 62 Oklahoma Anadarko 63 Kansas
7 Rocky Mountain	70 Utah - Aneth Field 71 San Juan Basin 72 Uintah-Green River Basin 73 Colorado-Julesburg Basin 74 Montana - Wyoming 75 Montana - Dakota
8 Other Areas	
South Alaska	
Gross Imports	Mexico Canada

Source: FPC Staff Report: Natural Gas Transported in 1974 in FPC Regulated Pipelines, October 1976.

FIGURE A-2. Natural Gas Market Areas

TABLE A-3. Natural Gas Market Area Codes

Major Market Area	Subarea	Major Market Area	Subarea
I New England	Connecticut	V Northern Plains	Iowa
	Maine		Minnesota
	Massachusetts		Nebraska
	New Hampshire		North Dakota
	Rhode Island		South Dakota
	Vermont	VI Mid-Continent	Kansas
II Appalachian	Delaware		Missouri
	District of Columbia		Oklahoma
	Kentucky	VII Gulf Coast	Arkansas
	Maryland		Louisiana
	New Jersey		Mississippi
	New York		Texas
	Ohio	VIII Rocky Mountain	Colorado
	Pennsylvania		Montana
	Virginia		Utah
	West Virginia		Wyoming
III Southeast	Alabama	IX Pacific Southwest	Arizona
	Florida		California
	Georgia		Nevada
	North Carolina		New Mexico
	South Carolina	X Pacific Northwest	Idaho
	Tennessee		Oregon
IV Great Lakes	Illinois		Washington
	Indiana	Gross Exports	Canada
	Michigan		Mexico
	Wisconsin		Japan

Source: FPC Staff Report: Natural Gas Transported in 1974 by FPC Regulated Pipelines, October 1976.

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