The original documents are located in Box 7, folder: "National Energy Outlook - 1976" of the Frank Zarb Papers at the Gerald R. Ford Presidential Library.

Chapter III

NATURAL GAS

INTRODUCTION

Natural gas is a vital source of energy for the United States, supplying about 30 percent of our total energy needs and 44 percent of non-transportation, direct uses. Concern regarding its continued role as a major U.S. energy supply source has risen because consumption has exceeded additions to proven reserves from the lower continental 48 States since 1968, and because interstate natural gas pipeline companies have been increasingly unable to meet their contracted delivery requirements to customers in many regions of the country.

Based on declining proven reserves of oil and natural gas, it is evident that a transition will take place over the next few decades from these less abundant domestic sources, to more abundant sources, such as coal, solar, and nuclear energy. However, the prospect of increased supplies of natural gas supplements, including synthetic gas from coal and pipeline-quality substitute gas from petroleum products, brightens the outlook for the natural gas industry. Also, prospects for improving the natural gas reserves base through development of advanced recovery techniques or new exploration could be significant.

In response to the recent natural gas shortages, the FEA, in cooperation with other Federal agencies, has performed intensive analyses into the short-term, mid-term, and long-term projected supply and demand for natural gas, including supplemental sources such as imported liquefied natural gas (LNG) and synthetic natural gas produced from coal and petroleum products. The major conclusion derived from these studies is that some fundamental decisions must be made now that will affect the contribution of natural gas and its pipeline supplements during the remainder of this century. The results of these studies and FEA's revised long-term forecasts are the basis for this Chapter.

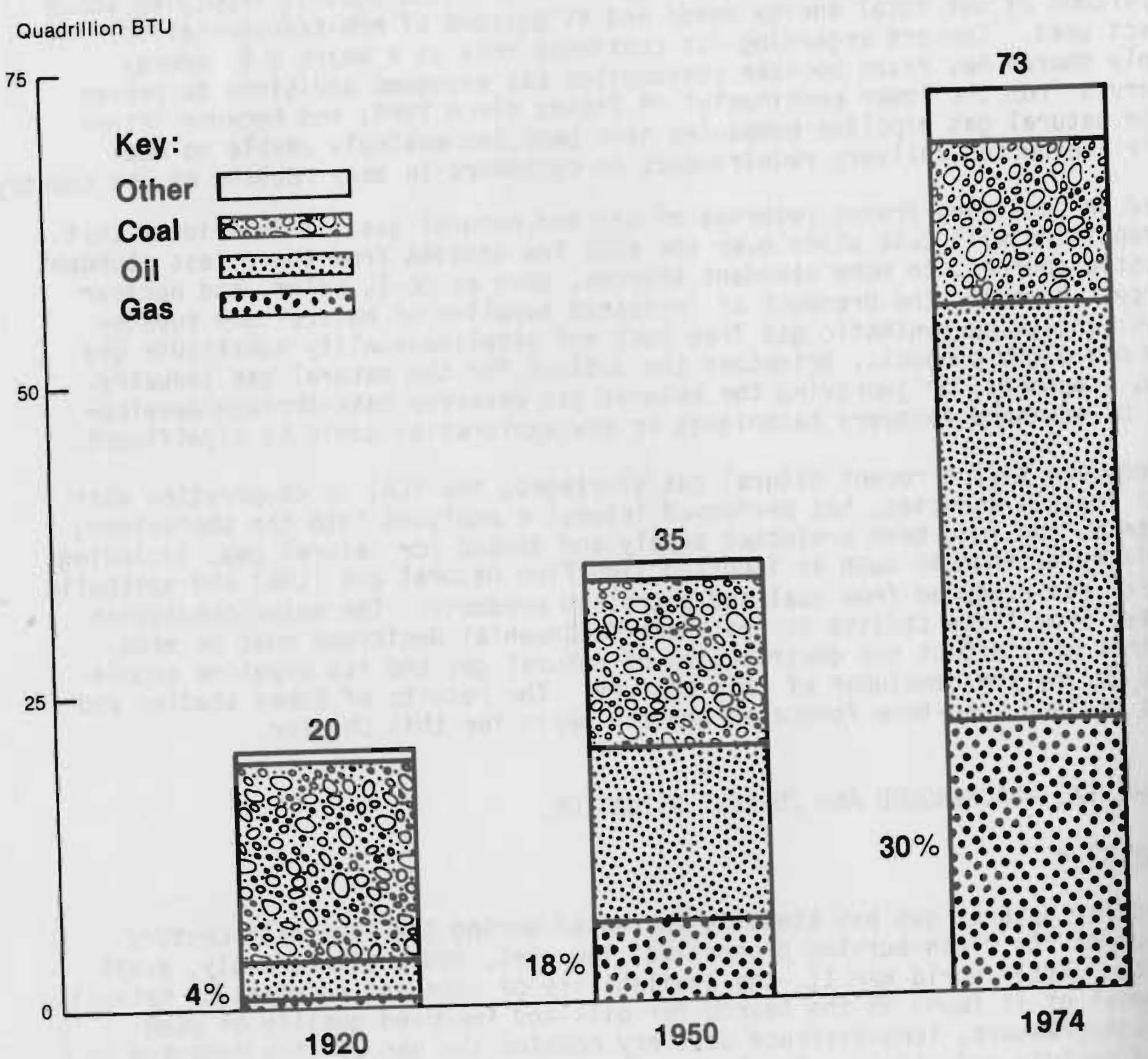
NATURAL GAS--BACKGROUND AND CURRENT SITUATION

Consumption

Demand for natural gas has steadily increased during the last half century because of its clean-burning properties, low cost, and until recently, availability. After World War II, the availability of abundant supplies of natural gas--most of it found in the search for oil--and improved quality of pipe for high-pressure, long-distance delivery enabled the gas utility industry to expand rapidly and widely. Total U.S. energy consumption of natural gas increased from 4 percent in 1920, to 18 percent in 1950, and exceeded 30 percent in 1974 (see Figure III-1), growing at an average of 6.5 percent annually

Figure III-1

Growth in U.S. Natural Gas Consumption 1920—1974



in the 1950's and 1960's. In 1974, it was consumed in over 40 million residences, in almost 3.4 million commercial establishments, and by over 193,000 industrial users.

Natural gas now accounts for over 50 percent of direct fossil fuel inputs to both the household/commercial and industrial sectors. Reliance on natural gas by the electric utility industry peaked in 1970, when natural gas accounted for almost 25 percent of total energy input. By 1974, natural gas generated only 17 percent of electricity, as curtailments and an inability to obtain long-term supply commitments affected its use.

The growth rate of natural gas consumption was reduced dramatically in the 1970's as compared to the previous decade. In particular, residential gas consumption declined in the early 1970's, following an annual growth rate of 4.5 percent in the previous decade (see Table III-1). Several factors accounting for this reduction include: the imposition of local moratoria on new additions of buildings to natural gas distribution lines for space heating, to offset rising interstate pipeline curtailments; warmer than normal weather in 1973 and 1974; voluntary conservation effects following the 1973 oil embargo; and a reversal in the decline in real prices for natural gas which prevailed in the 1960's.

Table III-1

SECTORAL GROWTH IN NATURAL GAS CONSUMPTION
(Tcf)

	1960	1970	1974	Annual Growth Rate 1960-1970	Annual Growth Rate 1970-1974
Residential	3.10	4.83	4.78	4.5	-0.3
Commercial	1.02	2.05	2.26	7.2	2.4
Industrial	4.34	7.87	8.29	6.2	1.3
Utility	1.73	3.89	3.41	8.5	-3.2
Total*	10.19	19.02	19.08	6.4	0.1

* Totals slightly exceed sum of four sectors due to inclusion of "Other Consumers" in BOM data and rounding.

Source: Bureau of Mines Mineral Industry Surveys--Delivered gas consumption

Government moratoria restricting new additions of residential consumers during 1974 were extensive (see Table III-2). There were only 17 States without restrictions; these were predominantly in areas where population is relatively sparse (Mountain States) or where gas is being produced and sold at unregulated prices (the West South Central region). However, 20 other States, principally those in areas served by interstate pipelines undergoing severe

Table III-2

EXTENT OF HOUSING CUSTOMER RESTRICTIONS, 1974*

Region	% of Utility Customers Covered By Restrictions	% of Utility Customers Not Covered By Restrictions	% of Utility Customers Not Covered By Survey	Number of States With Over 50% of Utility Customers With Restrictions	Number of States With 0% of Surveyed Utility Customers With Restrictions	Number of States in Region
New England	43	14	43	1	1	6
Middle Atlantic	97	0	3	3	0	3
East North Central	43	53	4	3	0	5
West North Central	22	66	12	1	1	7
South Atlantic	62	23	15	7	0	9**
East South Central	39	37	24	2	1	4
West South Central	0	79	21	0	4	4
Mountain	44	25	31	2	6	8
Pacific	3	96	1	1	3	5

* Customer restrictions refer to either restrictions imposed voluntarily by utilities in anticipation of supply shortages or those imposed upon the utility by state or municipal public utility commissions. The percentages cited above refer to the percentage of the total customers of a state that are served by utilities which restrict new customers for either reason and in any fashion.

** Includes District of Columbia.

Source: American Gas Association, Gas Heating Survey, 1975.

curtailments (Middle Atlantic, South Atlantic, and East North Central), had restrictions covering more than 50 percent of their residential gas utility customers.

The effect of warmer weather cannot be measured precisely. Although the weather in 1974 was colder than in 1973, natural gas consumption declined, primarily due to a reaction to the embargo, higher prices, and the recession. Further, real prices for natural gas in the residential sector declined by 1.5 percent annually between 1968 and 1972; but in 1973 and 1974 real prices increased by 0.7 percent annually.

Natural gas consumption within the commercial sector also grew at a much less rapid rate in the early 1970's, as compared to the preceding decade. Nevertheless, the commercial sector maintained positive growth in natural gas consumption from 1970-1974, growing by 2.4 percent annually.

The growth rate of natural gas consumption in the industrial sector declined in the 1970's principally due to the recession and to curtailments imposed by interstate pipelines and related gas utilities. The Middle Atlantic States experienced the largest decline in industrial natural gas consumption, dropping from a growth of 5.6 percent annually in the 1960's to a decline of 2.3 percent annually in the 1970's, principally due to the effects of pipeline curtailments.

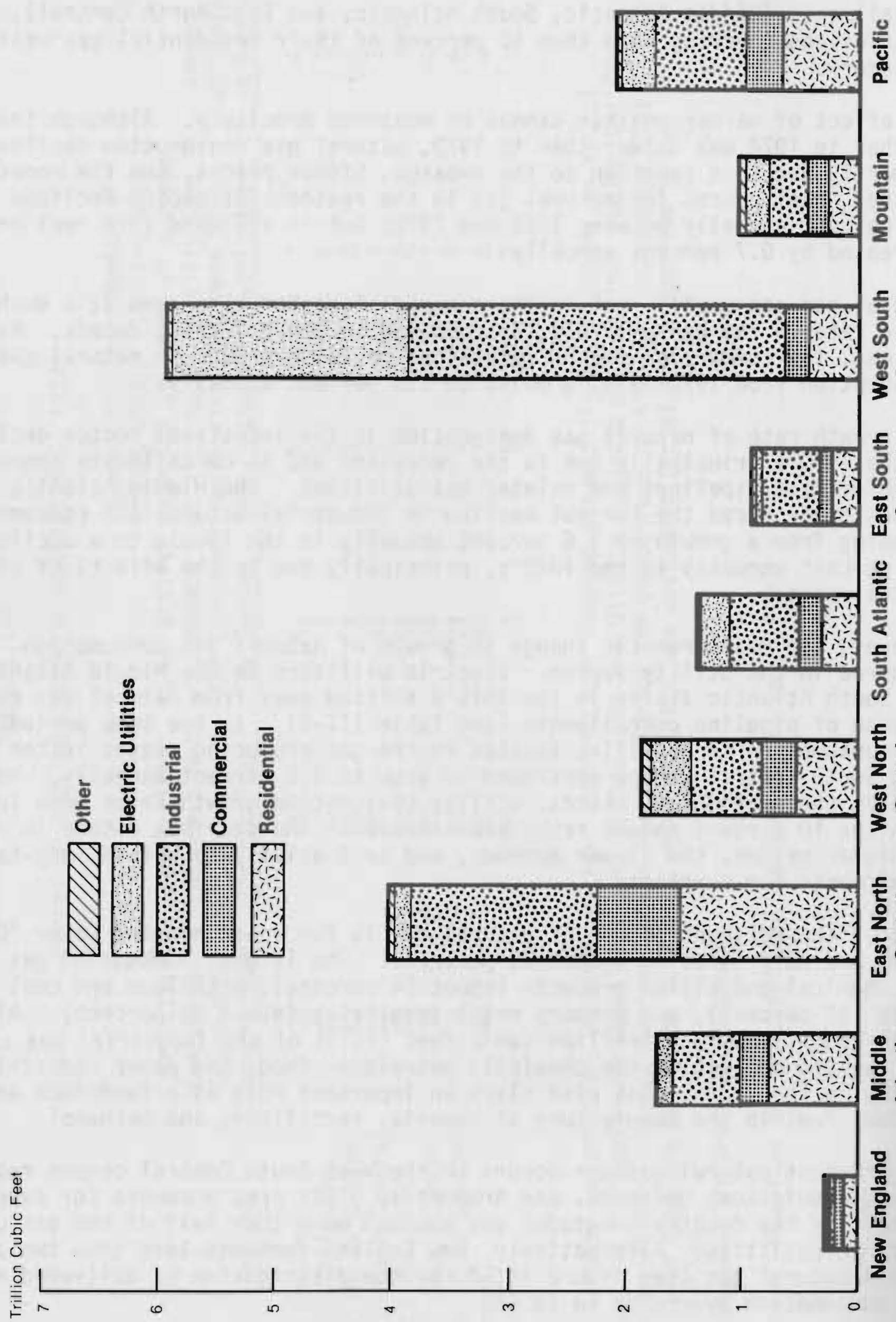
However, the most dramatic change in growth of natural gas consumption occurred in the utility sector. Electric utilities in the Middle Atlantic and South Atlantic states in the 1970's shifted away from natural gas mainly because of pipeline curtailments (see Table III-3). In the same period, gas consumption in utilities located in the gas producing states in the West South Central region continued to grow at 3.8 percent annually. However, even in these producing states, utility consumption growth rates were lower than the 10 percent annual rates experienced in the previous decade in response to higher prices, the slower economy, and an inability to obtain long-term commitments for supplies.

Most of the residential use of natural gas is for space heating (over 70 percent) and water heating (about 20 percent). The largest industrial gas users are chemical and allied products (about 24 percent), petroleum and coal products (16 percent), and primary metal industries (about 13 percent). Almost 40 percent (about 3.5 trillion cubic feet (Tcf)) of the industrial gas use is for fueling boilers in the chemical, petroleum, food, and paper industries, mostly in the South. Gas also plays an important role as a feedstock and process fuel in the manufacture of ammonia, fertilizer, and methanol.

The greatest natural gas use occurs in the West South Central census region (Texas, Louisiana, Oklahoma, and Arkansas). This area accounts for over 30 percent of the country's natural gas use and more than half of the gas used by electric utilities. Alternatively, New England consumes less than two percent of the natural gas (see Figure III-2 for the distribution of delivered natural gas consumption by region in 1974).

Figure III-2

Regional Distribution of Natural Gas Consumption, 1974



Note: Consumption Excludes Extraction Losses, Lease and Plant Fuel, Pipeline Fuel, and Transmission Losses.
Source: Mineral Industry Surveys, Bureau of Mines, Delivered Gas Consumption.

Table III-3

REGIONAL UTILITY NATURAL GAS CONSUMPTION
(Bcf/yr)

	Consumption 1960	1970	1974	Growth Rate 60-70	70-74
New England	13	8	11	(-4.7)	8.3
Mid Atlantic	89	161	61	6.1	(-21.5)
East North Central	61	245	167	14.9	(-9.1)
West North Central	245	420	365	5.5	(-3.4)
South Atlantic	147	343	240	8.8	(-8.5)
East South Central	53	139	53	10.1	(-21.4)
West South Central	657	1733	2012	10.2	3.8
Mountain	135	199	210	4.0	1.3
Pacific	324	645	310	7.1	(-18.0)
U.S.	1725	3894	3429	8.5	(-3.2)

Source: BOM Mineral Industry Surveys - Delivered Gas Consumption

Natural Gas Production and Distribution Industry

The U.S. natural gas industry is composed of producers, interstate and intrastate pipelines, distributors, and end-users. Currently there are about 12,000 oil and gas producers in the United States. In 1974, however, 34 companies accounted for 96 percent of the interstate volume, and the 25 largest interstate pipelines carried over 95 percent of the interstate gas (see Figure III-3).

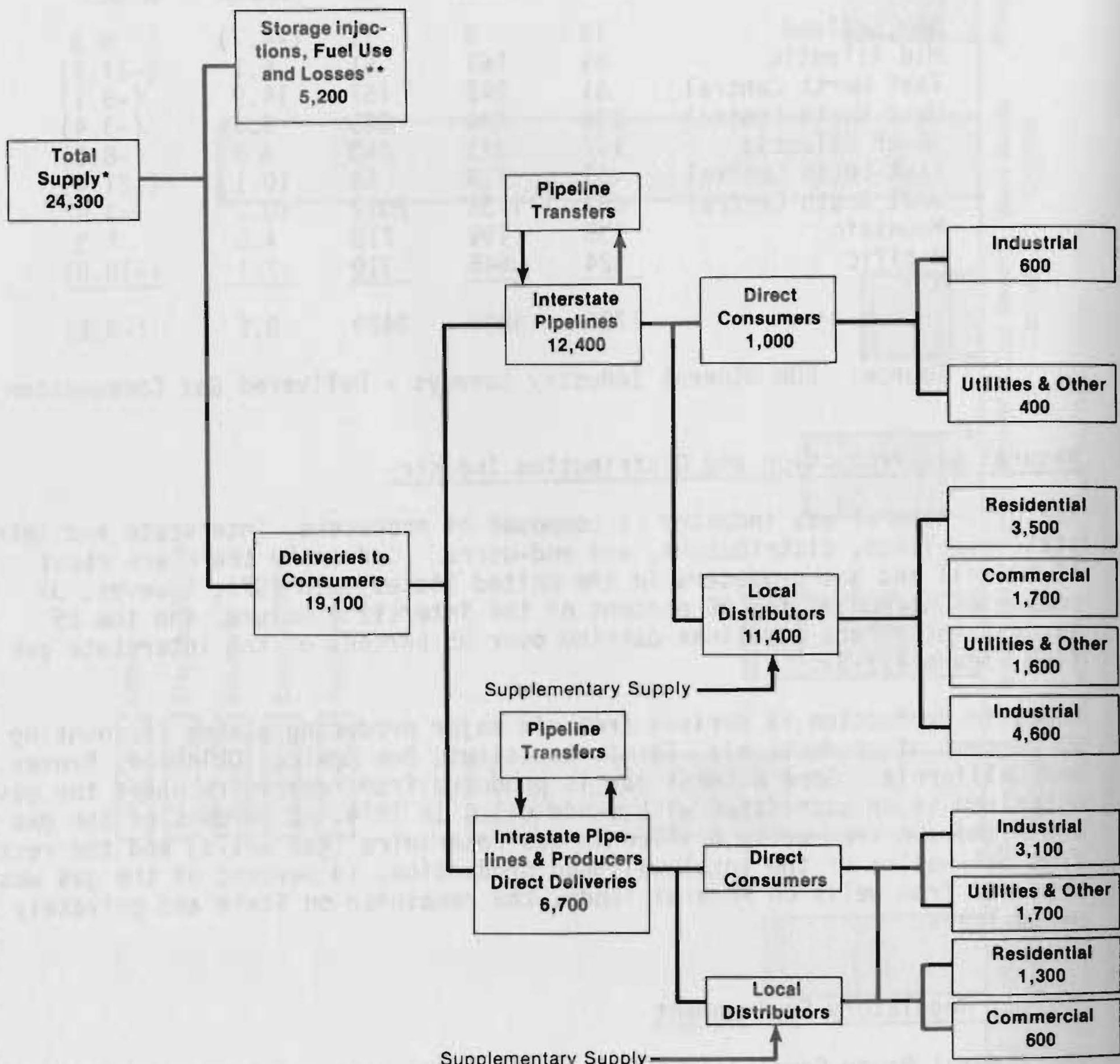
Domestic production is derived from six major producing states (accounting for 93 percent of production): Texas, Louisiana, New Mexico, Oklahoma, Kansas, and California. Some natural gas is produced from reservoirs where the gas is dissolved in or associated with crude oil. In 1974, 82 percent of the gas was withdrawn from wells drilled in gas reservoirs (gas wells) and the rest from oil wells; of the total wellhead production, 19 percent of the gas was produced from wells on Federal lands, the remainder on State and privately owned lands.

Current Regulatory Environment

The Federal Power Commission (FPC) exercises Federal regulatory jurisdiction over interstate transmission and sale of natural gas. It sets the maximum price a pipeline company may pay to producers for gas dedicated for resale to the interstate market, and controls the resale price of gas delivered to local distributing companies. Currently, a pipeline is allowed to pay a producer a maximum base price of 52¢ per thousand cubic feet (Mcf) for new gas, except on short-term emergency purchases by pipelines or purchases of uncommitted gas by curtailed, high priority customers from intrastate sources,

Figure III-3

Overview—U.S. Natural Gas System 1974 (Bcf)



*Supply includes U.S. marketed production, withdrawals from storage, and imports.
**Gas for such purposes as lease and plant fuel, pipeline compressor fuel, extraction loss, and transmission losses.

Note Divisions between interstate and intrastate volumes are estimated.

Source: Based primarily on data from "Natural Gas Production and Consumption: 1974" (Washington, DC: Bureau of Mines, Mineral Industry Surveys, 1975).

when higher prices may be paid. In contrast, unregulated prices for gas sold on the intrastate market usually range between $1.00 and $1.50 per Mcf.

Aside from controlling prices, the FPC regulates various other aspects of the interstate natural gas market, including the rates charged for the transportation of gas delivered into interstate commerce. Since 1970, when shortages first developed, the FPC has been responsible for establishing curtailment priorities and for approving curtailment plans filed by affected pipelines. It also regulates, through a certification process, the construction and abandonment of pipeline and storage facilities.

Because of its authority to control imports and exports, the FPC also has jurisdiction over imported LNG, but has jurisdiction over synthetic gas (syngas) from coal and substitute natural gas (SNG) from petroleum products or natural gas liquids only when these products are commingled with regular natural gas in interstate pipelines. Since each of these supplements costs pipelines more than natural gas, the FPC decides on a case-by-case basis whether they can be incrementally priced to individual purchasers of the supplement, or whether the higher prices will be averaged among all purchasers of natural gas. The FPC has ruled in favor of incremental pricing in projects reviewed to date, thereby lowering the incentive to obtain more gas from these sources, but assuring that new users pay the real marginal price for these costly supplements.

Natural gas distributors are regulated by State public utility commissions or municipal governments. This regulation covers the utility's service territory, the rates charged its customers, the construction of new facilities, and local curtailment priorities.

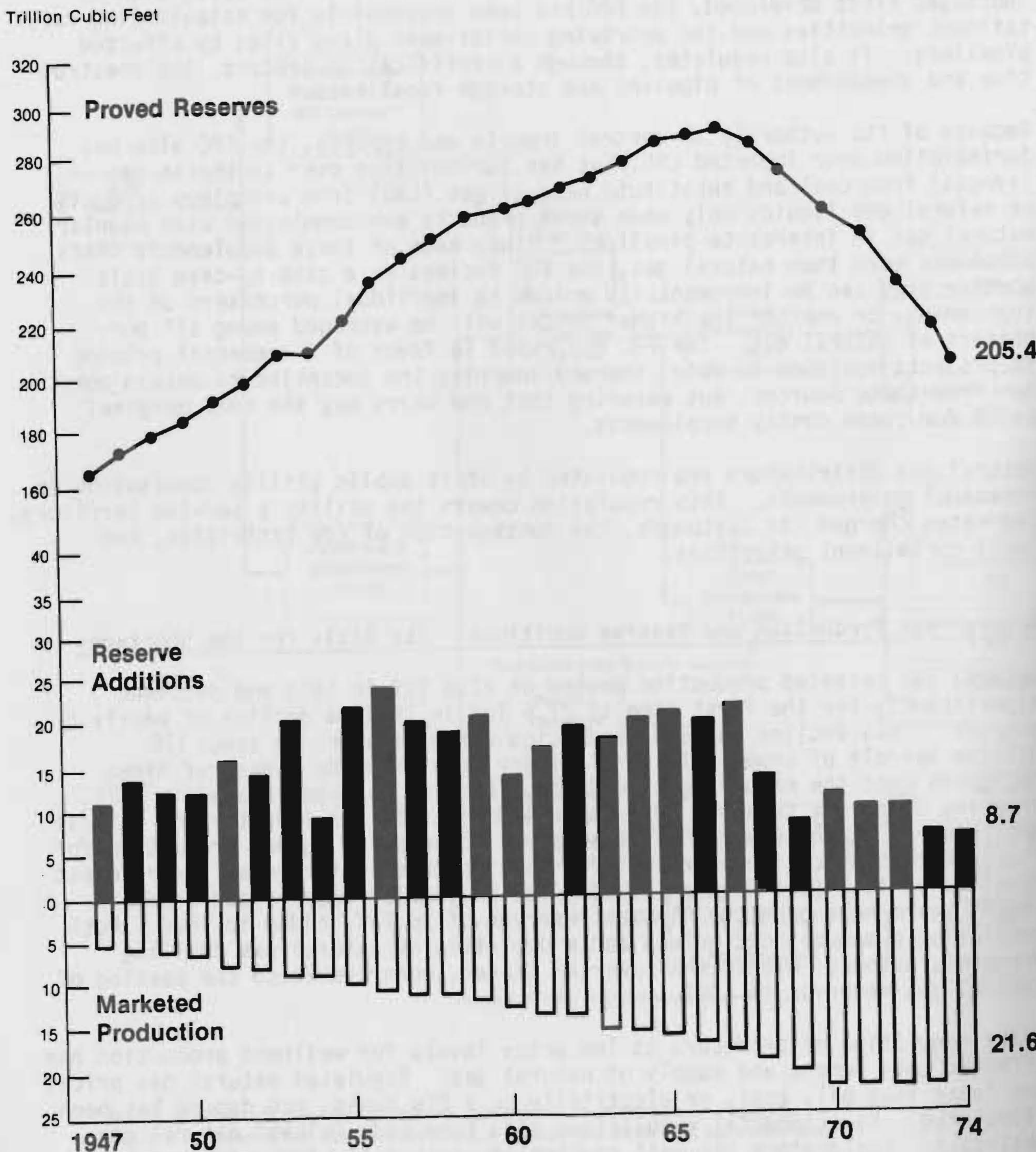
Natural Gas Production and Reserve Additions: The Basis for the Shortages

Natural gas marketed production peaked at 22.6 Tcf in 1973 and declined significantly for the first time to 21.6 Tcf in 1974, a decline of nearly 5 percent. This decline in 1974 production was equivalent to about 170 million barrels of crude oil. Preliminary data from the Bureau of Mines indicates that the natural gas production decline was accelerated in 1975, dropping 7 percent to about 20.1 Tcf. Additions to the inventory of natural gas reserves in the lower 48 States failed to equal or exceed production for the seventh consecutive year in 1974, leaving these reserves at their lowest level since 1952 (see Figure III-4). The only major reserve additions in recent years have been the Alaskan reserves of 26 Tcf, added in 1970. Both regulation over wellhead prices and a depletion of natural gas drilling prospects onshore, within the lower 48 States, contributed to the peaking of natural gas reserves in 1967.

Price regulation of producers at low price levels for wellhead production has affected both demand and supply of natural gas. Regulated natural gas prices are lower than oil, coal, or electricity on a Btu basis, and demand has been stimulated. Environmental regulations also have made "clean" natural gas desirable. Exploratory gas well completions peaked in 1959 and began a decline which continued until the early 1970's. However, in the early 1970's,

Figure III-4

U.S. Natural Gas Reserves (Excluding Alaska)



Source: American Gas Association.

increases in the unregulated prices for natural gas in the intrastate market stimulated a sharp increase in exploratory activity.

The depletion of prime natural gas drilling prospects also hastened the onset of natural gas shortages. The first natural gas areas explored are those least costly to drill and with the greatest likelihood of discovery of large fields. By 1974, the average reserve additions per foot drilled for exploratory and developmental wells was 170 Mcf per foot, compared to 485 Mcf per foot in 1970.

The interstate natural gas pipelines have suffered both from a decline in the total amount of reserves added to the inventory and from a decline in the share of reserves acquired by these systems. Since natural gas produced and sold within the same State is not regulated by the Federal Power Commission, the share of new reserve dedications to pipelines crossing State boundaries has fallen, while the intrastate market share has risen (see Figure III-5).

Curtailments to Date

Due to a continually increasing demand and a relatively stable rate of production, the demand for gas exceeded its supply in the 1970's. Many gas distribution companies have found it necessary to deny gas service to new customers and to curtail some existing customers. Firm curtailments (generally defined as contractual requirements less deliveries) as reported by the interstate pipelines grew from 0.1 Tcf in the 1970-71 delivery year (April-March) to 2.0 Tcf in 1974-75 (see Table III-4). For the delivery year 1975-76, firm curtailments were projected by the FPC at 2.9 Tcf, or 19 percent of requirements.

Table III-4

CURTAILMENT TRENDS*

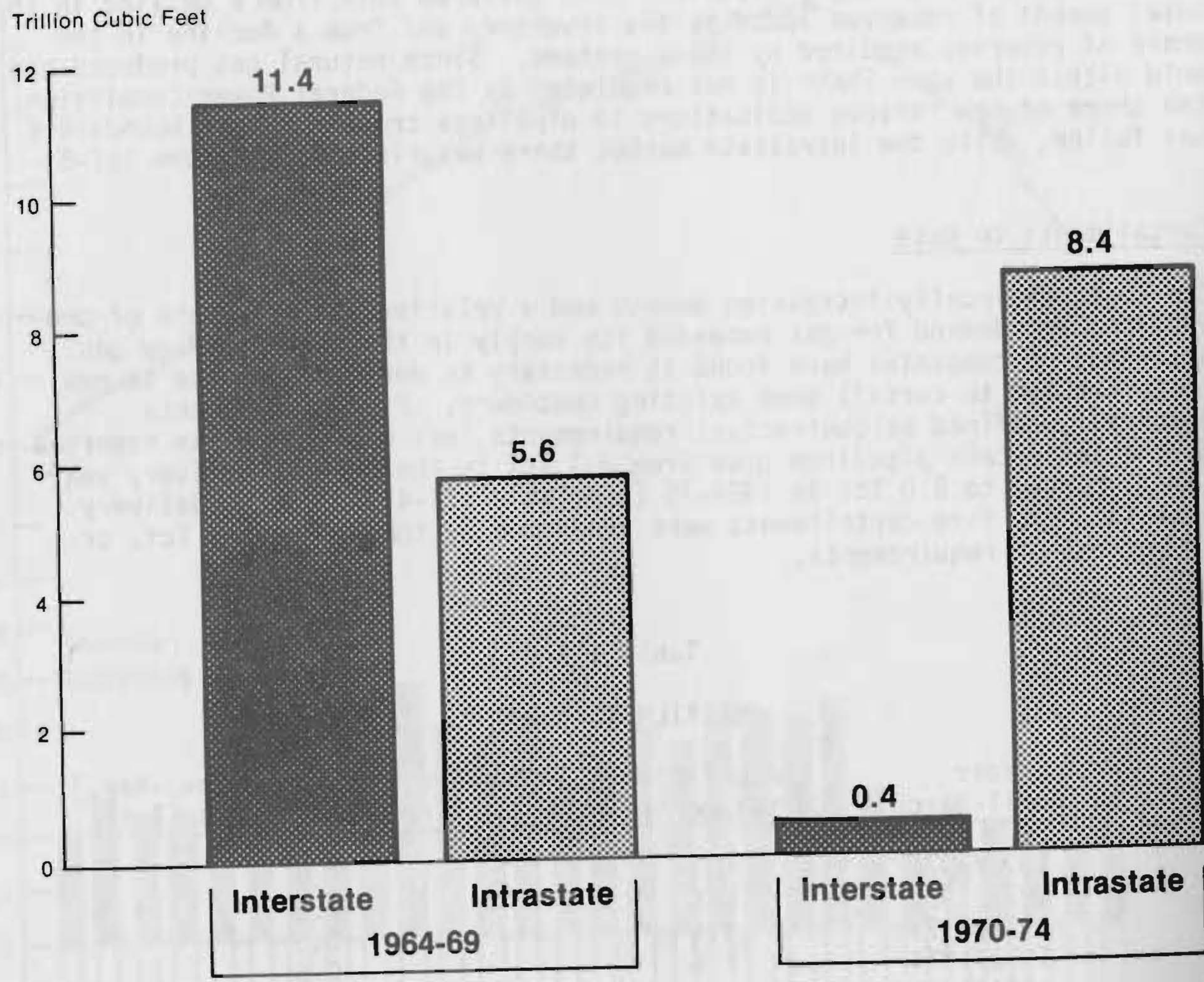
Year (April-March)	Annual Firm Curtailments (Tcf)	Heating Season (Nov.-Mar.) Firm Curtailments (Tcf)
1970/1971	0.1	0.1
1971/1972	0.5	0.2
1972/1973	1.1	0.5
1973/1974	1.6	0.6
1974/1975	2.0	1.0
1975/1976**	2.9	1.3

* Pipeline to pipeline curtailments not included in 1974/1975 data; contractual commitments, not incorporating an interruptible supply provision, are included.

** Previously estimated

Figure III-5

Average Annual Reserve Additions of Natural Gas



Source: American Gas Association, Federal Power Commission.

In 1970-71, when the Federal Power Commission began compiling data on curtailments, 12 of the 48 major interstate pipelines experienced curtailments. More pipelines with curtailments have been added to the list in each subsequent year. By the 1975-76 heating season, 31 of the 48 pipelines were projecting curtailments. However, six of these accounted for about 65 percent of projected firm curtailments and about 40 percent of the total firm requirements.

A few key pipelines experiencing substantial curtailments serve the States most affected (see Figure III-6). These States are the Atlantic States stretching south from New York; several Mid-Western States, such as Ohio and Kentucky; and California. Estimates of the natural gas shortages in the 21 States most affected are shown in Table III-5.

Due to increasing curtailments, the FPC in March 1973, promulgated a uniform, nine-tier curtailment priority schedule based on the end use of the gas and size of the customer. Under this schedule, residential and small commercial users are afforded the highest priority during service curtailments, followed by large commercial users and industrial users who cannot switch to alternate fuels.

The priority of distribution in the final market usually depends on policies established by the state regulatory agencies, which vary substantially among states. A recent survey of 21 States* indicated that only six had statewide uniform curtailment policies. Seventeen of the states imposed curtailments on an end-use basis, curtailing industrial, commercial, and residential customers in that order. The others approved pro rata curtailment plans, usually curtailing the larger volume users on an equal share basis, and not distinguishing between industrial and commercial usage. Nineteen out of 21 States also distinguished between firm and interruptible contracts in assigning curtailment priorities. However, all State provided residential users the highest priority for continuous gas service.

Curtailments on the interstate pipeline system have not caused large adverse economic impacts to date. Most of the curtailments have been absorbed by industrial users on firm contracts, but having alternate fuel use capabilities. Customers on interruptible contracts frequently absorbed curtailments through shifts in production schedules and through use of alternate fuels. However, curtailments beginning in the winter of 1974-1975 reached into levels of the industrial market sector which either could not use alternate fuels by nature of their processes, or which have not yet installed alternate fuel use capability.

There is, of course, an economic impact involved in the shift to alternate fuels. Industrial plants must eventually recoup the cost of higher-priced alternate fuels, as well as the capital costs of installing alternate fuel

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* Conducted by the FEA Natural Gas Task Force in the Fall of 1975.

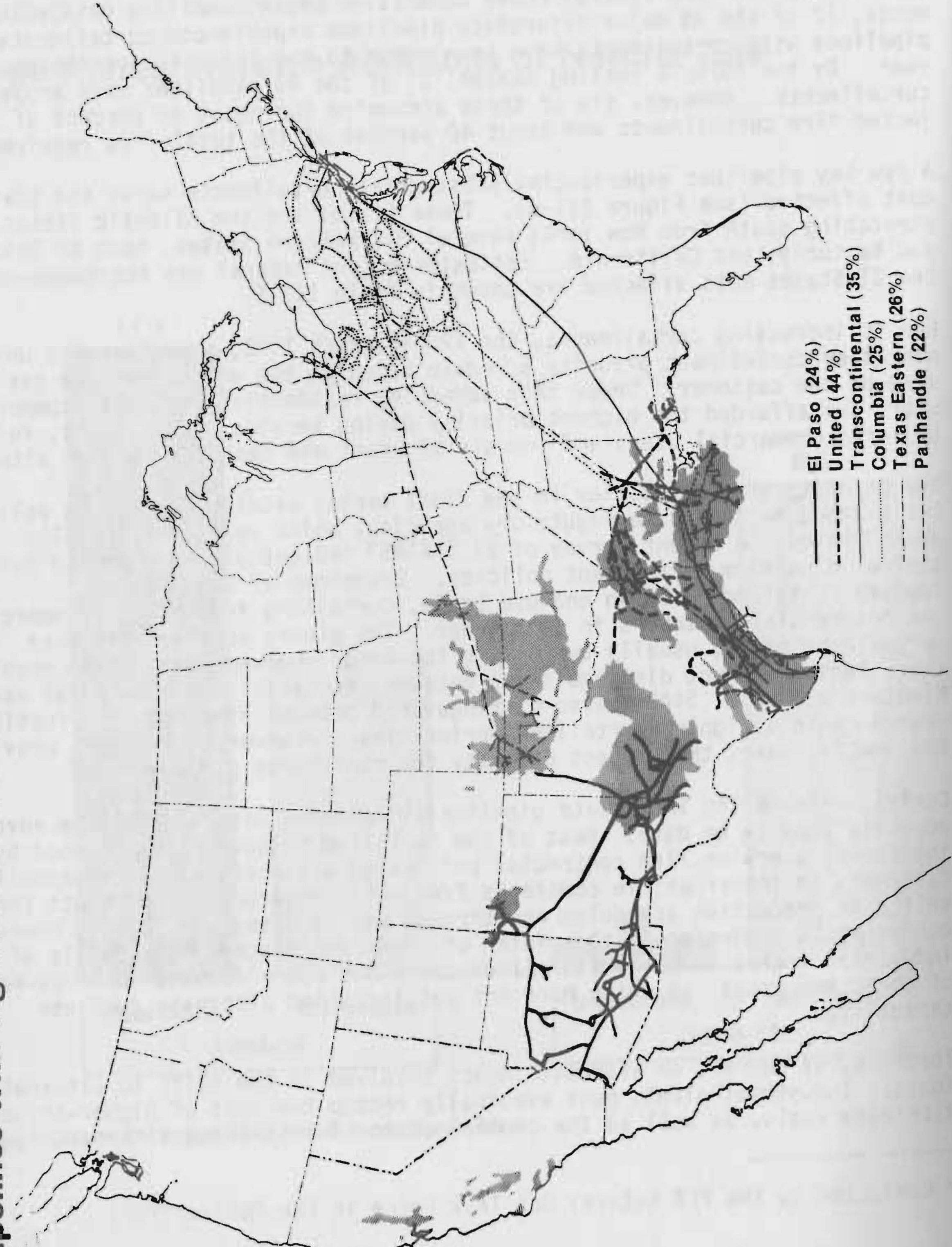


Figure III-6

Major Natural Gas Producing Regions And Pipelines With Significant Curtailments

Table III-5

PROJECTIONS OF NATURAL GAS SHORTAGE DURING WINTER OF 1975-1976 IN MOST-AFFECTED STATES

	Total Curtailments		Increase Over Last Winter
	Bcf	Percent of Requirements	Bcf
Arizona	22	24	2
California	370	34	46
Delaware	1	12	0
Florida	50	49	10
Georgia	63	29	11
Indiana	17	6	5
Iowa	36	18	4
Kansas	60	23	5
Kentucky	13	10	6
Maryland/D.C.	14	12	1
Missouri	35	15	5
Nevada	24	51	6
New Jersey	21	11	(-10)
New York	41	10	6
North Carolina	41	46	6
Ohio	78	12	11
Pennsylvania	37	9	10
South Carolina	59	55	4
Tennessee	31	22	9
Virginia	12	14	(-1)
West Virginia	12	13	3

Source: FEA/FPC Distributor Survey, updated December 1975 burning facilities, through higher product prices. In addition, the increased demands for alternate fuels by natural gas curtailees have intensified supply problems in other sectors of the energy industry, especially in the propane market.

In the winter of 1974-75, very little unemployment and few plant shutdowns occurred directly as a result of natural gas unavailability. Most plant closings occurred primarily because of the recession and many shutdowns were avoided by the use of alternate fuels (propane, butane, distillate, or residual oil), emergency diversion of natural gas, mild weather, or conservation. There were reports of scattered plant closings for brief periods during the heating season in Virginia, North Carolina, New Jersey and other States.

NEAR-TERM OUTLOOK

The natural gas supply available to the interstate pipelines will continue to decline throughout the next several years in the absence of a major shift in supplies from the intrastate market. The FPC has predicted that, based on the total gas reserves committed to the interstate pipelines at the end of 1974 under all contracts and commitments, the annual decline in deliveries would be about 1 Tcf through 1979 if these supplies were not augmented (see Table III-6), or a doubling of current curtailments within three years. Potential supply additions include increased production from newly dedicated reserves to the interstate market, increased supplies from the intrastate market through emergency and short-term contracts, and increased imports.

The volume of new reserve additions is likely to be insufficient to replace the 1 Tcf/year expected decline, even if all production from new reserves was dedicated to the interstate market, an unlikely event. The outlook for increased imports through 1979, either by pipeline from Canada or in the form of LNG, is exceedingly unlikely because of recent declarations of energy resource conservation from Canada and the long lead times needed to obtain project approval and to construct LNG gasification terminals. Also, even if prices increase under deregulation, production levels will not increase for at least the next few years, although more gas would be available in the interstate market.

FEA estimates a substantial increase in the natural gas shortage in 1976-77 as the economy reaches normal levels of activity. Forecast is an increase of about 1.3 Tcf for the delivery year and 0.8 Tcf for the winter heating season as compared to the corresponding period in 1975-76. In addition, severe weather conditions (equivalent to the coldest winter in the last 10 years) could increase the natural gas shortage by about 200 Bcf in any winter.

The states most affected by shortages this year will experience greater impacts in the winter of 1976-77 as the supply situation of the interstate pipelines serving them continues to deteriorate. Although the shortage is not projected to reach the residential sector, the industrial and electric utility sectors will experience even greater shortfalls as the economy recovers.

Table III-6

GAS SUPPLY AND DELIVERABILITY
DEDICATED TO INTERSTATE PIPELINE COMPANIES THROUGH 1974
(Bcf/yr)

	Produced and/or Purchased 1974	Projected Deliveries 1975	1976	1977	1978	1979
A. Domestic Gas Supply						
Company Owned and Long Term Producer Contracts	12,513	11,606	10,595	9,557	8,517	7,579
Warranty Contracts	226	218	248	250	235	224
Emergency/Limited Term Contracts	226	0	1	0	0	0
Total Domestic	12,965	11,824	10,844	9,807	8,753	7,803
Domestic % of Total	93.5	92.8	92.1	90.1	87.4	85.8
B. Pipeline Imports						
Canada	900	922	927	930	932	933
Mexico	0	0	0	0	0	0
Total Pipeline Imports	900	922	927	930	932	933
Pipeline Imports % of Total	6.5	7.2	7.9	8.5	9.3	10.3
C. LNG Imports						
Algeria	-0-	-0-	-0-	146	332	360
LNG Imports % of Total				1.4	3.3	3.9
D. Total All Sources, All Contracts and commitments	13,866	12,746	11,772	10,883	10,016	9,097

Source: Federal Power Commission-Preliminary Data

Several factors can substantially reduce the effects of natural gas curtailments. The most important factor will be the availability and cost of alternate fuels. Others include the heating demand by residential and commercial customers which is a function of the temperature; the extent to which industrial activity dependent on natural gas has recovered from the economic downturn, the actual supply deficits, emergency purchases of uncommitted gas, and fuel savings by conservation efforts. As an example, the warm weather in the early part of the 1975-76 heating season relieved the pressure in some areas, reducing by December 1975 the forecast of curtailments by about 160 Bcf in the most seriously impacted States.

LONG-TERM OUTLOOK FOR NATURAL GAS

The interstate pipeline curtailment problem facing the country in the near term is but a symptom of a fundamental long-term inability of domestic natural gas supplies to meet demand at the presently regulated price levels. The resulting shortage is thus focused and amplified in several States due to the structure of the current pricing regulations. The long-term outlook for natural gas supply and demand is uncertain and dependent on several factors.

Long-Term Outlook for Natural Gas Demand

The potential demand for natural gas in the long term is influenced by the following:

- The world pricing strategy for oil, since natural gas and oil are close substitutes in both the utility and industrial sectors;
- The degree and structure of price regulations over domestic oil;
- Government conservation initiatives, particularly those directed to buildings and industry, and the degree of commercialization of existing energy-saving technologies in these sectors;
- Government policy regarding the availability of natural gas for use in utility and industrial boilers;
- The status of local government moratoria.

The long-term forecasts for natural gas demand are highly uncertain since natural gas average prices have never been in the high ranges estimated for the 1985 strategies, and the effects of both government-induced and voluntary conservation cannot be established with precision. In addition, the response to higher prices in each consuming sector is uncertain since projections are based on current consumption patterns which are a derivative of over 20 years of price regulations, and the establishment of two distinct markets for gas--the controlled interstate and unregulated intrastate markets.

Reference Scenario Demand Forecast

Natural gas demand in the Reference Scenario is expected to increase from the actual consumption of 21.2 Tcf measured in 1974 to 23.4 Tcf by 1985 (see Table III-7). However, combining reported interstate curtailments of 1.9 Tcf with actual consumption provides an indication of the "unconstrained" demand for natural gas of about 23.1 Tcf for 1974. Thus, aggregate demand for natural gas in 1985 will remain about the same as the unconstrained demand observed in 1974, if world oil prices remain at current levels and both new natural gas and oil prices are deregulated.

Table III-7

1985 NATURAL GAS DEMAND BY SECTOR AND WORLD OIL PRICE
(Tcf/yr)

Reference Scenario	1974	Oil Import Price ($/bbl) $8	$13	$16
Residential & Commercial	7.3	6.4	6.2	6.3
Industrial	9.9	13.9	13.6	13.6
Transportation	0.6	0.8	0.8	0.8
Utility	3.4	0.5	3.0	3.2
Total Demand	21.2	21.5	23.4	23.7

Note: Totals exclude about 0.2 Tcf of synthetic gas consumed by the sectors.

Aggregate demand for natural gas in 1985 is not heavily influenced by the world price of oil, decreasing by only 8 percent (to 21.5 Tcf) if world oil prices drop to $8 a barrel, and increasing by only 1 percent (to 23.7 Tcf) if world oil prices increase to $16 per barrel.

Although there will be little change in aggregate demand for natural gas from the unconstrained demand level observed in 1974, large changes can occur in individual sectors. The industrial sector is shown in the $13 Reference Scenario to increase consumption by 3.7 Tcf (or 37 percent) over 1974 levels, while usage in the residential/commercial sector decreases by 1.1 Tcf (15 percent).

Although these sectoral forecasts are consistent with trends of recent years, the forecast for natural gas consumption in the residential/commercial sector may be understated since the economic forecasting techniques employed are projecting from a baseline--the first half of the 1970's--that has been affected by local government moratoria on connections of gas lines to new buildings, interstate pipeline curtailments, and warm weather. Thus, the baseline does not represent a true unconstrained demand condition, from which the unconstrained demand under unregulated conditions is being forecast.

The Reference Scenario sectoral forecast should instead be viewed in terms of the combined potential growth in natural gas consumption in the residential and industrial sectors. The actual distribution of the gas consumption in these sectors will depend on several factors, particularly the rate in which the local government restrictions on space-heating additions are removed. The forecast indicates that about 2.6 Tcf of growth will be distributed in these sectors.

At current world oil prices, natural gas usage in the Utility Sector declines by 13 percent to 3.0 Tcf. This means that with new natural gas and oil prices decontrolled, virtually no new gas driven turbines will be used to generate electricity. Available gas will instead be used by industry and in buildings.

An increase in the world price of crude oil from $13 to $16 per barrel will not have much effect on sectoral natural gas consumption. However, with new natural gas prices deregulated, a decrease in world oil prices to $8 per barrel will drive most natural gas out of utilities. Utility gas consumption would decline to 0.5 Tcf as the lower oil price causes extensive switching from natural gas to oil in power plants.

Alternative Scenarios

Unconstrained natural gas demand does not vary significantly as different government actions are implemented due to the compensating movement of natural gas prices (see Table III-8). However, natural gas domestic production declines significantly if natural gas price controls remain, leaving large shortfalls which must be satisfied by oil or gas imports.

The projected aggregate demand for natural gas cannot be met in all scenarios combining projected domestic production with a realistic estimate of natural gas imports. Natural gas imports in 1985 will be composed principally of imported LNG and Canadian pipeline gas. Canada is expected to provide about 0.87 Tcf/year based on the Canadian Natural Energy Board's current schedule of deliveries. Imported LNG is expected to vary between 0.4 Tcf and 2.1 Tcf annually, depending on the level of government encouragement as demonstrated through subsequent policy statements and further project approvals. Thus, realistic estimates of natural gas imports available by 1985 lie within the range of 1.0 to 3.0 Tcf per year.

As shown in Table III-8, in the Regulatory and Supply Pessimism Scenarios, the projected natural gas import requirements far exceed those which can realistically be considered attainable. Import requirements above 3.0 Tcf will be manifested as pipeline curtailments, and this unsatisfied natural gas demand will have to be satisfied through the use of alternate fuels, predominantly natural gas liquids, petroleum products, and perhaps electricity.

Table III-8

1985 NATURAL GAS DEMAND AT $13/BBL OIL IMPORTS
(Tcf/yr)

PIES Scenario	U.S. Demand	Production	Imports	Average Price***
Reference	23.4	22.1	1.3	$2.03
BAU Supply with/ Conservation	23.1	21.8	1.3	$1.87
Accelerated Supply Without Conservation	26.6	25.3	1.3	$1.48
Supply Pessimism	24.7	17.2	7.5*	$1.84
Continued Current Regulation	23.4**	17.9	5.5*	$1.88
Gas Price Ceiling of $1/Mcf ($7.50 Regulatory)	24.2	17.0	7.3*	$1.83

* Exceeds maximum available natural gas imports and would have to be replaced by oil imports or electricity.
** Estimated.
*** Average prices shown consist of a weighted average of domestic natural gas wellhead prices from all producing regions and imports, including transportation costs to the city gates, to satisfy all demand regions.

Long-Term Outlook for Supplies of Natural Gas and Pipeline Supplements

The long-term supplies available through natural gas pipelines include domestic natural gas production (including Alaskan gas and supplies obtainable from tight gas formations, Devonian shale, and offshore areas), pipeline imports from Canada, liquefied natural gas imports and natural gas manufactured from petroleum products (SNG) or coal (syngas).

In viewing the total potential for natural gas supplies and its pipeline supplements in the long term, price, and therefore the degree of price regulation, is a critical factor. However, there are other factors that could greatly affect domestic exploration and production, including government policy concerning:

- Leasing of Outer Continental Shelf areas;
- Timing and ultimate construction of an Alaskan transportation system to transport production from the vast gas reserves at Prudhoe Bay;
- Acceptable LNG import levels and price;
- Pricing of SNG and construction of SNG plants;
- Research and Development to extend the natural gas resource base, including recovery from tight formations and Devonian shale;

• Possible financial support and regulatory control over the commercialization of synthetic gas from coal.

Summary of Methodology in PIES Supply Model

The Nation's total gas production is derived from gas wells which produce no oil (nonassociated gas), and from oil wells which produce both gaseous and liquid hydrocarbons (associated-dissolved gas). The supply of nonassociated gas is most sensitive to wellhead prices, while the supply of associated gas is primarily dependent upon the price of crude oil. Therefore, two separate models are used to estimate supply from these two sources to obtain FEA projections for production from the lower 48 States and the Outer Continental Shelf.

The FEA model for nonassociated gas supply activities has been designed to independently treat production rates, reserves depletion, exploration, drilling rates, and investment costing on a regional basis, given estimates of the undiscovered natural gas resource base. Provision has also been made to account for additional complexities inherent with exploration behavior under the influence of changing prices, and to capture distortions in drilling patterns that occur when very large gas fields are discovered in newly developed areas. Independent engineering estimates for a few special geographic gas regions and geologic formations are included to complete the regional supply curves for nonassociated gas production over the next 15 years.

A second model is utilized to estimate associated gas supply. Essentially, historical data from each region are utilized to derive a ratio of associated gas production to oil production, and the resulting supply curve for associated gas is a derivative of the oil model's supply curve for oil (see Appendix A for more details on the methodology used in the models, and Chapter II for a discussion of the oil production price response).

In comparison to last year's Project Independence Report, the price levels required to retain present production rates of nonassociated gas will be substantially higher. This is chiefly because the USGS reduced estimates of the resource base, smaller gas finding rates per unit of drilling were assumed, and the model was adjusted to account for the recent alterations in the depletion allowance. Further, new procedures were incorporated into the model which both related and extended estimates of the drilling and gas production responses to higher prices, removing simplifications in the original methodology.

Previously, the level of drilling was determined using one drilling curve available for all prices. This curve was selected to approximate the drilling that would be forthcoming at wellhead prices of 80¢/Mcf in 1973 dollars. This simplification was used in the original study because the judgments at that time were that these prices and quantities would be sufficient to achieve equilibrium, and the focus was on evaluating fuel substitution--not the evaluation of supply increments at higher prices. Other

improvements in FEA demand estimates have altered the equilibrium price calculations and motivated the more extensive treatment summarized here.

The revised supply model produces estimates of natural gas production which recognize the difference in costs and, therefore, prices of producing from reserves of different size and quality. This price sensitivity is essential in evaluating the impacts of fuel competition or in assessing the potential supply results from gas price deregulation.

Domestic Natural Gas Production Price Sensitivity

This section describes the impact of prices on natural gas supply, including gas produced from domestic sources but excluding liquefied natural gas, synthetic gas from petroleum or coal and imported natural gas.

If new natural gas prices are deregulated and real uncontrolled oil prices remain at their current level, FEA estimates that total domestic production will be 22.3 Tcf in 1985 at an average price of $2.03/Mcf. If current natural gas regulation persists, production would decline to 17.9 Tcf and the interstate share of this production would be reduced drastically. Alternatively, if natural gas prices are set at $1.00/Mcf at the wellhead in both the interstate and intrastate markets, this supply estimate could drop to 17.0 Tcf. The sensitivity of these aggregate estimates can be displayed by separating the discussion into the contribution of total supply that comes from nonassociated gas and that which comes from associated gas.

Nonassociated Natural Gas Production

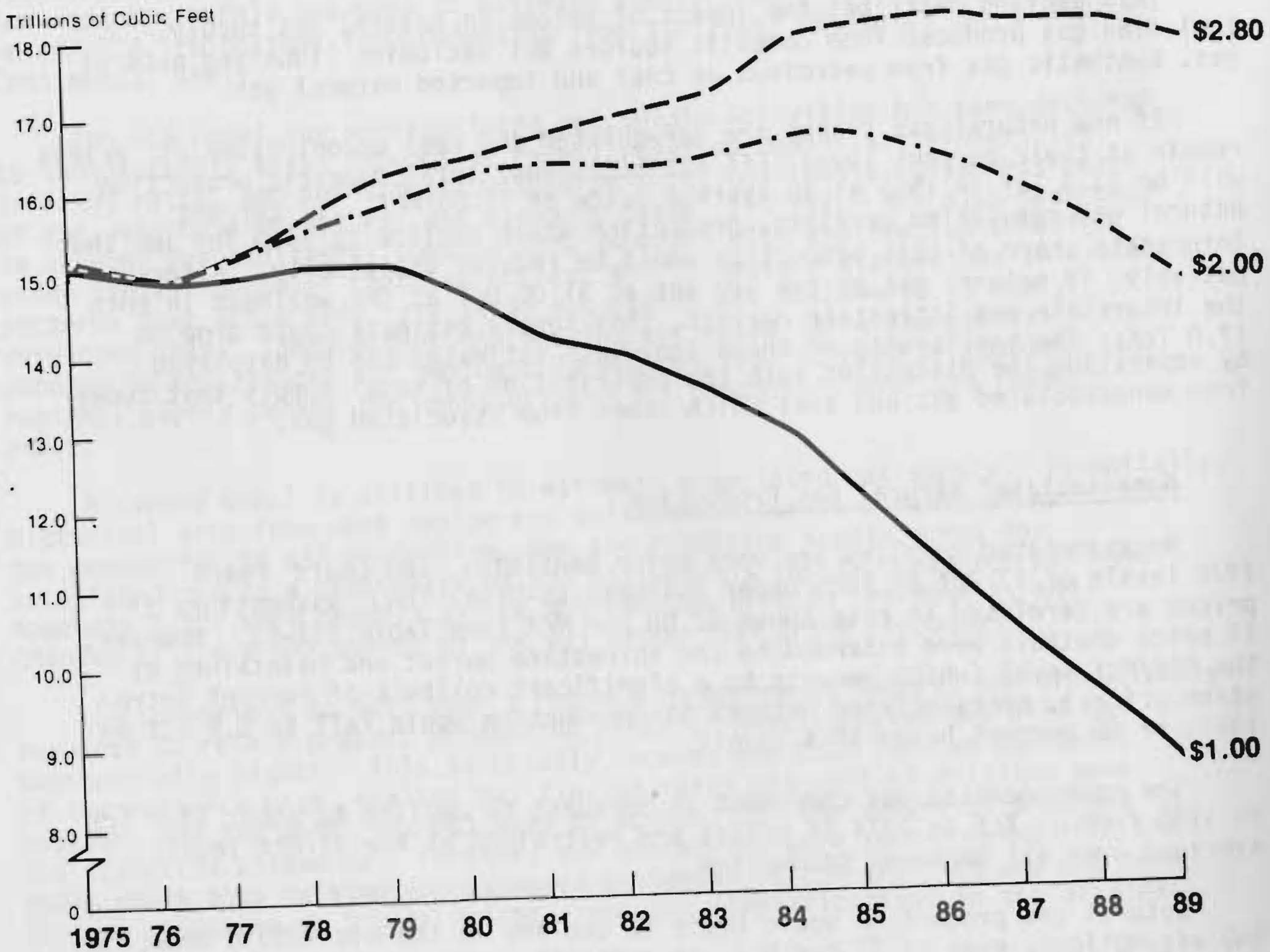
Nonassociated supplies are very price sensitive, and could reach 1974 levels of 17 Tcf by 1985 under Business-as-Usual (BAU) assumptions if prices are permitted to rise above $2.00 per Mcf (see Table III-9). However, if price controls were extended to the intrastate market and maintained at the 52¢/Mcf level (which amounts to a significant rollback of current intrastate prices), nonassociated natural gas production would fall to 5.8 Tcf by 1985, or 66 percent below 1974 levels.

The nonassociated gas component is forecast to decline to about 13.5 Tcf in 1985 from 17 Tcf in 1974 if prices are restrained at the $1/Mcf level, averaged over all marketed production.

Natural gas production would begin to decline in the mid-1980's under BAU assumptions, even at $2 per Mcf, as remaining reserves in onshore areas are depleted. For this same reason, production at prices as high as $2.80 per Mcf under BAU assumptions peaks in 1986 and declines thereafter (see Figure III-7).

Figure III-7

Non-Associated Natural Gas Production from the Lower-48 States and the O.C.S. at Three Wellhead Price Levels



NOTE: These quantities include gas used for repressurization of wells; excludes tight gas.

Table III-9

1985 NONASSOCIATED NATURAL GAS SUPPLY RESPONSE--BUSINESS-AS-USUAL (Tcf)

Price $/Mcf	Nonassociated Gas*	Nonassociated Gas in Special Regions**	Total Nonassociated Natural Gas
$0.52	5.86	.00	5.86
1.00	13.31	.17	13.48
1.70	16.12	.46	16.58
2.00	16.64	.46	17.10
2.80	18.20	.46	18.66

* Excludes special regions. Quantities of nonassociated natural gas are presented for a Btu-equivalent petroleum price.

** Southern Alaska and tight gas. The non-responsiveness of supply at higher prices is due to logistic and institutional constraints.

Most of the production response to price increases above $1 per Mcf comes from more intensive production on onshore fields. As natural gas prices vary from $1/Mcf to $2/Mcf, production would increase by 25 percent in the Western Gulf Basin and Mid-Continental regions and about 100 percent in the West Texas area (see Table III-10).

However, Gulf of Mexico offshore yields are constrained by the acreage leased by the government for exploration and drilling, which is assumed independent of price. The OCS leasing schedule is the prime determinant of frontier OCS gas production (given fixed geological expectations) at prices above about 80¢ per Mcf. In addition, the long lead times required for production in some frontier areas constrain the supply response to price seen through 1985, and thus a greater elasticity of supply may actually be shown in the post-1985 period.

At $2 per Mcf, production from Louisiana and Texas would decline from 1974 levels by about 1 Tcf, but this loss is projected to be offset by increased production from the Gulf of Mexico, bringing total nonassociated gas production to near-1974 levels.

The sensitivity of these production estimates to factors other than price have been examined under two separate sets of assumptions other than BAU. The important pessimistic or optimistic assumptions are summarized in Table III-11.

Table III-10

NON ASSOCIATED GAS PRODUCTION ESTIMATES--BUSINESS-AS-USUAL (Bcf/yr)

Code	Region	Actual 1974 Production	1985 Production Price ($/Mcf) 1.00	1985 Production Price ($/Mcf) 2.00	Difference in Production Estimates: $2 From $1 Price	Difference in Production Estimates: $2 price from 74 Actual
2	Pacific Coast States	156	53	62	9	(-94)
2a	Pacific Ocean (OCS)	20	0	48	48	28
3	Western Rocky Mountains	626	318	465	147	(-161)
4	Eastern Rocky Mountains	311	462	662	200	351
5	West Texas-E. New Mexico	2201	887	1839	952	(-362)
6	Western Gulf Basin	6422	4368	5545	1177	(-877)
6a	Gulf of Mexico (OCS)	3528	4493	4493	0	965
7	Mid Continent	3269	2569	3221	652	(-48)
8&9	Mich.Basin,E. Interior	103	33	46	13	(-57)
10	Appalachians	331	129	255	126	(-76)
11	Atlantic Coast	0	0	0	0	0
11a	Atlantic Ocean (OCS)	0	0	0	0	0
	Total	16967	13312	16636	3324	(-331)

Table III-11

OPTIMISTIC AND PESSIMISTIC OUTLOOK ASSUMPTIONS

	Pessimistic	BAU	Optimistic
Resource Assessment	USGS "Mean" Minus 36%*	USGS "Mean"	USGS "Mean" Plus 36%*
OCS Leasing**	18.7 Million Acres	27.7 Million Acres	39.7 Million Acres
Investment Tax Credit	10% through 1977; 7% thereafter	10% through 1977; 7% thereafter	10% throughout

* These represent ± 1 standard deviation around the USGS "statistical" mean.

** Oil leasing not separated from gas leasing here.

The Optimistic and Pessimistic cases reflect the considerable uncertainty as to the size of the natural gas resource base of the United States. In recent years, the USGS has substantially reduced its estimates of our total undiscovered gas (including Alaska), from 2100 Tcf in 1972 to a 1000 to 2000 Tcf range in 1974, and then to its most recent estimate of 322 to 655 Tcf, made in 1975. The mean estimate, adjusted for water depths greater than 200 meters, is the primary natural gas data source utilized in the BAU cases. The major source of reserves is still located onshore in the lower 48 States (see Table III-12). Optimistic and Pessimistic geological outlooks vary considerably in offshore areas which are largely unexplored (see Table III-13). Historically most of the search for new reserves has focused on oil rather than natural gas, and thus the uncertainty surrounding the gas reserve estimates far exceeds that for oil reserves.

Although estimates of undiscovered resources are unimportant for short-term (1- to 5-year) production projections, they become increasingly important for longer-term analysis. If the U.S. production were to continue only from existing reserves through 1985, nonassociated production would drop to 5.6 Tcf in 1985 and to 3.4 Tcf in 1989 (see Table III-14). Thus, the currently unknown amount of gas that actually exists will begin to bear heavily upon discovery and production rates in the mid-1980's and beyond, and becomes the driving factor in long-range supply projections.

The Optimistic and Pessimistic cases also reflect the influence that changes in the rate of leasing of the offshore areas can have on nonassociated production. However, changes in geological expectations are the dominant factor driving differences in the production response in both the Pessimistic and Optimistic cases as compared to the BAU case.

Table III-12

RESERVES AND UNDISCOVERED RESOURCES OF NATURAL GAS
FOR THE UNITED STATES*
(Tcf)

	Reserves		Undiscovered Recoverable Resources	
	Measured	Inferred	Statistical Mean	95%-5% Range
Lower 48 Onshore	169	119	345	246-453
Alaska Onshore	32	15	32	16-57
Total Onshore	201	134	377	264-506
Lower 48 Offshore	36	67	101	42-178
Alaska Offshore	0	0	44	8-80
Total Offshore	36	67	145	50-248
Total U.S.	237	202	522	338-722

* Lower 48 States offshore estimates have been adjusted for OCS resources at greater than 200 meters, increasing mean estimate by 38 Tcf; includes associated-dissolved and nonassociated gas.

Table III-13

ALTERNATIVE GEOLOGICAL OUTLOOKS*
(Tcf)

Category	Pessimistic	Business-as-Usual	Optimistic
Measured Reserves	237.1	237.1	237.1
Inferred Reserves	201.6	201.6	201.6
Subtotal: Reserves	438.7	438.7	438.7
Undiscovered Recoverable			
Lower-48 Onshore	247	345	443
Lower-48 Offshore	52	101	150
Alaska Onshore	19	32	45
Alaska Offshore	9	44	79
Subtotal	327	522	717
Total	766	961	1156

* Includes associated-dissolved and nonassociated natural gas; adjusted for water depths greater than 200 meters.

Table III-14

NONASSOCIATED GAS PRODUCTION FROM RESERVES EXISTING IN 1974

Year	Production
1975	15.1
1977	12.9
1980	9.6
1985	5.6
1989	3.4

Under Optimistic conditions, total gas production in 1985 is estimated to increase above the BAU case by 2.5 Tcf (15 percent) at $2 per Mcf prices, and 2.3 Tcf (17 percent) at the $1 per Mcf price (see Table III-15). The Gulf of Mexico offshore region, most sensitive to these altered assumptions, increased 43 percent at the $2/Mcf price and 36 percent at the $1/Mcf price level (see Table III-16). Almost three-fourths of the increased production from the Gulf of Mexico at either price level is attributable to Optimistic resource estimates, virtually all of the remainder due to accelerated leasing.

Table III-15

NONASSOCIATED GAS PRODUCTION--1985
(Tcf)

Wellhead Price (1975 $)	Pessimistic	BAU	Optimistic
$1.00	12.0	13.3	15.6
$2.00	15.2	16.6	19.1
$2.80	16.2	18.1	20.9

Optimistic conditions delay the decline in nonassociated natural gas production (see Figure III-8 for production estimates for all three cases through 1989 at $2/Mcf). Under Optimistic conditions production reaches over 19 Tcf in 1986, while under BAU production declines after reaching 16.7 Tcf in 1984. By 1989, production only drops 0.6 Tcf from 1985 levels under Optimistic resource assessments, while under BAU, production drops over 1.8 Tcf from 1985 levels. Under Pessimistic conditions, production rises slightly after 1976 to about 15.7 Tcf in 1980, and then drops to about 14.0 Tcf by 1989.

Drilling is expected to be extremely sensitive to price changes under all three outlooks. In 1974, the footage drilled for gas wells (with dry holes allocated) totaled about 63 million feet. However, in the BAU case at $2 per Mcf, the average annual footage drilled is projected at 87 million feet from 1975 through 1980, and 92 million feet from 1981 through 1985.

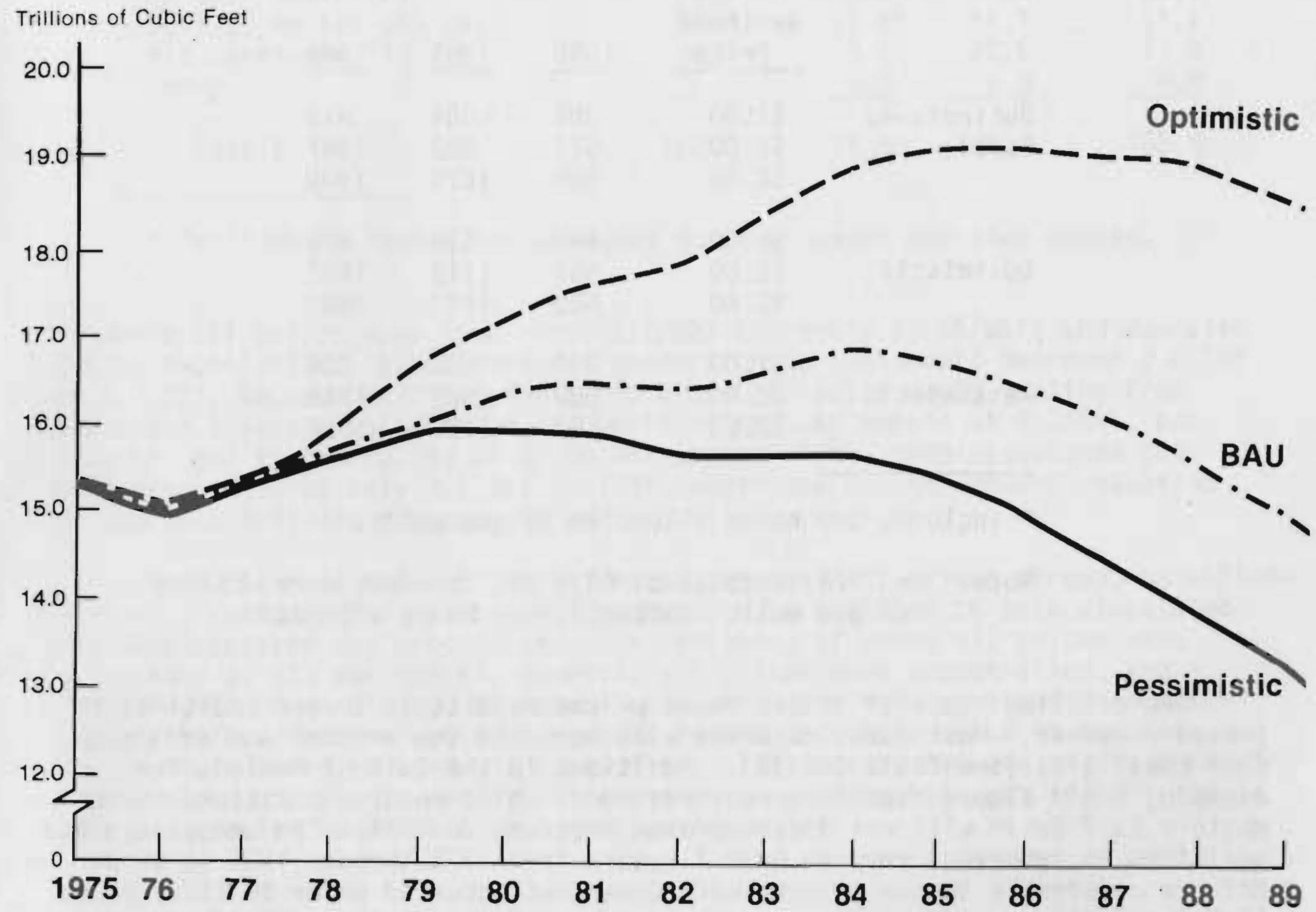
Table III-16

NONASOSCIATED GAS PRODUCTION ESTIMATES--1985
(Bcf/yr)

Code	Region	$1/Mcf BAU	$1/Mcf Optimistic	$2/Mcf BAU	$2/Mcf Optimistic
2	Pacific Coast States	53	53	62	62
2a	Pacific Ocean (OCS)	0	35	48	53
3	Western Rocky Mountains	318	361	465	504
4	Eastern Rocky Mountains	462	546	662	732
5	West Texas-E. New Mexico	887	1193	1839	2059
6	Western Gulf Basin	4368	4391	5545	5688
6a	Gulf of Mexico (OCS)	4493	6103	4493	6413
7	Mid Continent	2569	2773	3221	3343
8&9	Mich. Basin, E. Interior	33	33	46	46
10	Appalachians	129	129	255	269
11	Atlantic Coast	0	0	0	0
11a	Atlantic Ocean (OCS)	0	0	0	0
	Total	13312	15617	16636	19169

Figure III-8

Non-Associated Natural Gas Production from the Lower-48 States and the O.C.S. Under Three Sets of Assumptions



NOTE: These quantities include gas used for repressurization of wells; excludes tight gas.

The cumulative drilled footage doubles from 1975 through 1985 in the BAU case as the price is increased from $1 to $2 per Mcf (see Table III-17). Drilling increases by 136 million feet (14 percent) in 1985 at the $2 price level under the Optimistic case, as compared to BAU conditions. In the Pessimistic case drilling drops 57 million feet as compared to BAU at $2/Mcf.

Table III-17

PROJECTED FOOTAGE DRILLED FOR GAS WELLS, CUMULATIVE FROM 1975*
(Millions of Feet)

	Wellhead Price	1980	1985	1989
Business-As Usual	$1.00	308	404	419
	$2.00	521	982	1381
	$2.80	586	1275	1970
Optimistic	$1.00	446	618	618
	$2.00	551	1118	1632
	$2.80	623	1443	2301
Pessimistic	$1.00	285	333	335
	$2.00	509	925	1210
	$2.80	561	1105	1606

* Includes dry holes allocated to gas wells.

Note: In 1974, a total of 63.5 million feet were drilled for gas wells, including dry holes allocated.

The drilling response to increased prices results in larger additions to proved reserves. Most added reserves will occur in the onshore and offshore Gulf Coast area (see Table III-18). Additions in the Gulf of Mexico, for example, could almost double current reserves, while reserve additions in the Western Gulf Basin will not exceed proved reserves in 1974. The annual average additions to reserves computed over 11 years from 1975 through 1985 at $2 per Mcf are comparable to the reserve additions that occurred prior to 1970, about 15 Tcf annually.

Associated Gas Production

While most natural gas is supplied from wells devoted solely to producing gas, large amounts of production are possible from oil wells. In 1974, this associated gas production amounted to 4.2 Tcf. At current world oil prices and with domestic oil prices deregulated, associated gas production is forecast at 4.9 Tcf in 1985. However, both the degree of control over domestic oil prices and the world price of oil will affect associated gas production. For instance,

Table III-18

NONASSOCIATED REGIONAL GAS RESERVE ADDITIONS (Tcf)
(BAU)

Region	1974 Proved Reserves	Reserves Added 1975-1985 Wellhead Prices ($/Mcf) 0.60	1.00	2.00
Eastern Rocky Mountain (4)	4.6	0.0	4.4	11.3
W. Texas - E. New Mexico (5)	14.4	0.0	8.9	26.2
W. Gulf Basin (6)	59.8	0.0	17.3	38.1
Gulf of Mexico OCS (6a)	30.9	11.6*	51.1	51.1
Mid Continent (7)	30.8	0.0	22.6	31.5
Other	21.7	0.0	1.0	9.8
Totals	162.2	11.6	105.3	168.0

* Drilling in region 6a commences for four years and then ceases.

if world oil prices drop from about $13/bbl currently to $8/bbl, and domestic oil is decontrolled, associated gas production in 1985 could decrease 0.8 Tcf to 4.1 Tcf, because drilling for exploratory oil wells would decline from projected levels. In addition, if world oil prices remain at $13/bbl, but domestic oil is controlled at $7.50/bbl through 1985, then associated gas production will be only 3.5 Tcf in 1985, again due to the induced reduction in domestic drilling for new oil wells.

A reduction of natural gas prices at constant oil prices through establishment of a ceiling would affect oil production in addition to both associated and nonassociated gas production. For instance, if world oil prices were maintained at $13 per barrel, domestic oil prices were uncontrolled, and a natural gas price ceiling was established at $1 per Mcf, combined associated gas and oil production would be reduced by 2.8 Tcf, with about 65 percent of this loss being reduced oil production. This occurs because of the reduced exploration activity in geological areas which produce both gas and oil due to reduced expected revenues by oil and gas companies.

The Reference Scenario

The BAU supply curve is input into the PIES model to determine the Reference Scenario--that is, the market clearing price at which supply and demand are at equilibrium in an uncontrolled market or deregulated condition. At current world oil prices, about 22.3 Tcf of natural gas would be produced domestically in 1985 at an average price of $2.03 per Mcf (see Table III-19). Of this production, 78 percent would be nonassociated gas including 165 Bcf from tight formations. Of the remaining 4.9 Tcf of associated gas, 835 Bcf would be transported from Northern Alaska by a pipeline expected to be operational in the early 1980's (see later discussion in this Chapter).

Table III-19

REFERENCE SCENARIO PRODUCTION

World Oil Price $/bbl	1985 Domestic Production (Tcf) Nonassoc.	Assoc.	Total	Price $/Mcf* Nonassoc.	Assoc.	Avg.
$8	16.3	4.1	20.4	$1.90	$1.67	$1.79
$13	17.4	4.9	22.3	$2.13	$1.93	$2.03
$16	17.4	5.1	22.5	$2.16	$1.97	$2.07

* The average price is the city gate price for domestic gas and imports; prices for nonassociated and associated gas reflect marginal wellhead prices for new gas.

In addition to this domestic production, 1.27 Tcf of natural gas imports are purchased at the import price of $2.14 per Mcf. This represents 0.4 Tcf of liquefied natural gas already contracted for and approved by the FPC, and 0.87 Tcf of pipeline imports from Canada pursuant to the Canadian National Energy Board's current schedule of deliveries.

If oil prices drop from $13 per barrel to $8 per barrel, natural gas prices are pulled down to approximate a Btu-equilibrium with lower priced oil in the utility sector, and the total production of natural gas declines. However, as world oil prices increase to $16 per barrel, little effect is noted on natural gas production and prices as compared to the $13/bbl case, since no significant fuel switching response in the utility sector is stimulated.

Continued Current Regulations Scenario

To project prices and production levels in 1985 if current regulations over natural gas were maintained, a special methodology had to be constructed to model the effects of maintaining two distinct markets--the unregulated intrastate market and the regulated interstate market. A regulated supply curve was constructed and allowed to equilibrate with a regulated demand curve to produce a new production and price level. The following assumptions were made:

- All West South Central gas consumption was considered intrastate gas.
- The 1974 ratio of OCS to non-OCS contracts will be maintained under continued regulation.
- The West South Central intrastate market can be assumed representative of all domestic intrastate markets.
- Quantities under existing interstate contracts will continue to decline at a rate of 7 to 8 percent per year.
- The ratio of non-West South Central, non-Alaskan production to West South Central production will continue at its 1974 level.

- The intrastate demand curve for West South Central will be stable under deregulation, i.e., the regulated and deregulated intrastate equilibria are on the same demand curve.

In the Continued Regulations Scenario only the intrastate market will be in equilibrium. Gas from the onshore areas would be produced until demand in this market is satisfied at a new contract price of about $1.80/Mcf. Offshore and Alaskan gas production, on the other hand, would be restricted by an assumed FPC field price ceiling of about $.60/Mcf plus any cost-of-living adjustments. Total marketed production is forecast at 17.9 Tcf for the Nation, although only 6.6 Tcf of this would be allocated to the interstate market (see Table III-20). Curtailed industrial users would be forced to purchase imported oil.

Table III-20

PROJECTED INTERSTATE/INTRASTATE SALES UNDER DIFFERENT POLICIES--1985

	Marketed Production Gross	Net*	Sales Interstate*	Intrastate*
Actual 1974	21.6	18.8	11.6	7.2
Present Regulation - 1985	17.9	15.9	6.6	9.3
Deregulation - 1985 (Reference Scenario)	22.3	20.0	12.1	7.9

* Gas consumed by end-users from domestic sources, excluding liquefied natural gas, synthetic fuels, and imported natural gas. Total gas consumption (including these other sources) would be greater.

The differences between deregulation and regulation are substantially more pronounced for interstate supply than for total national production. With the continuation of the present regulations at today's prices (in constant dollars), interstate supply would decline about 5.0 Tcf below its 1974 level of 11.6 Tcf--a reduction of 43 percent. If new gas is deregulated, the higher gas prices would allow large volumes of gas to enter the interstate market, because not only will more offshore and Alaskan gas be produced but also some onshore gas will be bid away from the intrastate market. Under these conditions, the decline in interstate sales would be halted, resulting in slightly more sales than its present level by 1985.

Alternative Scenarios

FEA analyzed the effects of a number of possible policy variations on natural gas production, consumption, and price. If development of resources is accelerated by increasing leasing and if geology is favorable, production possibilities could increase to more than 25 Tcf and price would decline (see Accelerated Supply Scenario on Table III-21). The lower prices result because lower cost production is made available to meet demand. In economic terms, the supply curve is shifted to the right on a relatively elastic demand curve, yielding increased supplies at lower prices.

Table III-21

NATURAL GAS PRODUCTION AND PRICES FOR ALTERNATIVE SCENARIOS
($13 Oil Imported)

	1985 Production Tcf			Price $/Mcf	
Scenario	Nonassoc.	Assoc.	Total	Nonassoc.*	Avg**
Reference	17.4	4.9	22.3	$2.13	$2.03
BAU Supply With/ Conservation	16.9	4.9	21.8	$1.98	$1.87
Accelerated Supply Without Conservation	19.0	6.3	25.3	$1.59	$1.48
Supply Pessimism	14.2	3.0	17.2	$1.12	$1.84
Continued Current Regulation	13.9	4.0	17.9	$1.81	$1.88
Gas Price Ceiling of $1/Mcf	13.5	3.5	17.0	$1.04	$1.83

* Marginal price across all gas production regions of new nonassociated gas only.
** Average is weighted average of domestic natural gas and imported gas, transported to city gate for all demand regions.

Government conservation measures tend to reduce demand, thereby reducing production requirements to meet demand and lowering prices. For instance, conservation measures added to the Reference Scenario result in the lower average natural gas prices observed in the BAU Supply with Conservation Scenario $1.87/Mcf as compared to $2.03/Mcf in the REference Scenario).

Although price regulations shown in the $1.00 Regulation Scenario and the Supply Pessimism Scenario succeed in holding down domestic wellhead prices, average natural gas (or equivalent fuel) prices will not be reduced significantly below those of the Reference Scenario, due to large quantities of imports needed to meet demand.

Delivering Alaskan Natural Gas

Although estimates for associated gas from the North Slope of Alaska were included in the Reference Scenario projections already discussed, a separate section is devoted here to the special problems involved in accessing this gas.

Alaska has the largest known U.S. reserves of undeveloped natural gas potential: 26 Tcf of associated gas in the Prudhoe Bay area, 2 Tcf in the Cook Inlet

area, and 2 Tcf in other areas. The National Petroleum Council and the U.S. Geological Survey estimates undiscovered resources ranging between 16 and 57 Tcf onshore, and between 8 and 80 Tcf offshore (95 percent probability of at least the first; 5 percent probability of as much as the second number in each range).

In addition to the North Slope gas, there are some 3.6 Tcf of proved non-associated gas reserves in Canada's Mackenzie Delta area; another 2.8 Tcf are expected to be added to the proven reserves for this area in the near term. Estimated future potential of Canada's Mackenzie Delta is an additional 49 Tcf.

The Arctic Challenge

Transportation in the Arctic presents unusual challenges because of the cold climate, remoteness, long distances, and the permafrost. The land is permanently frozen in the Arctic (in some places to a depth of 2,000 feet) except for an active surface layer of a foot or two which thaws in summer. Permafrost problems are most severe near rivers and deltas. When the moisture-laden surface layer thaws during the summer, these areas become spongy swamps over which ground transport is often impossible.

If the surface layer of moss lichen and other small plants are disturbed for any reason, the summer heat penetrates to the permanently frozen ground underneath and the ground melts. Water runoff erodes the area and disturbs more of the surface layer. A small wash can quickly become a 20-foot-deep mud slough, which will continue to spread each summer. Off northern Alaska, ice conditions become so severe that in some places the sea is open for navigation only one or two weeks a year.

Bringing the Gas South

Transportation of Alaskan gas to the lower 48 States is the subject of intense competition between two proposed alternative routes. Issues include the relative economics of the systems, Alaskan/Canadian environmental concerns, Alaskan economic development policy, U.S.-Canada relations, Canadian domestic policies, financing, possibility of delay, location of natural gas delivery, and lower 48 saftey concerns.

The Arctic Gas consortium proposes about 200 miles of line eastward from Prudhoe to the Canadian border, 2,400 miles of Canadian line from the Yukon-Alaska border to South Alberta and two branches of line in the United States: 1,600 miles in Montana, North and South Dakota, Minnesota, Iowa, Illionis, Indiana, Ohio, West Virginia to Delmont, Pennsylvania; and about 280 miles through Idaho and Washington to Stanfield, Oregon (see Figure III-9).

The El Paso group proposes 809 miles of pipeline from Prudhoe along the Alyeska corridor to a gas liquefaction plant and terminal in Southern Alaska. From there, the LNG would be shipped by cryogenic tanker to a receiving terminal and regasification plant in Southern California (see Figure III-10). Although the Alaskan gas would be introduced at the West Coast, El Paso expects to make increasing supplies of natural gas available to the Mid-West

Figure III-9
Proposed Arctic Gas System

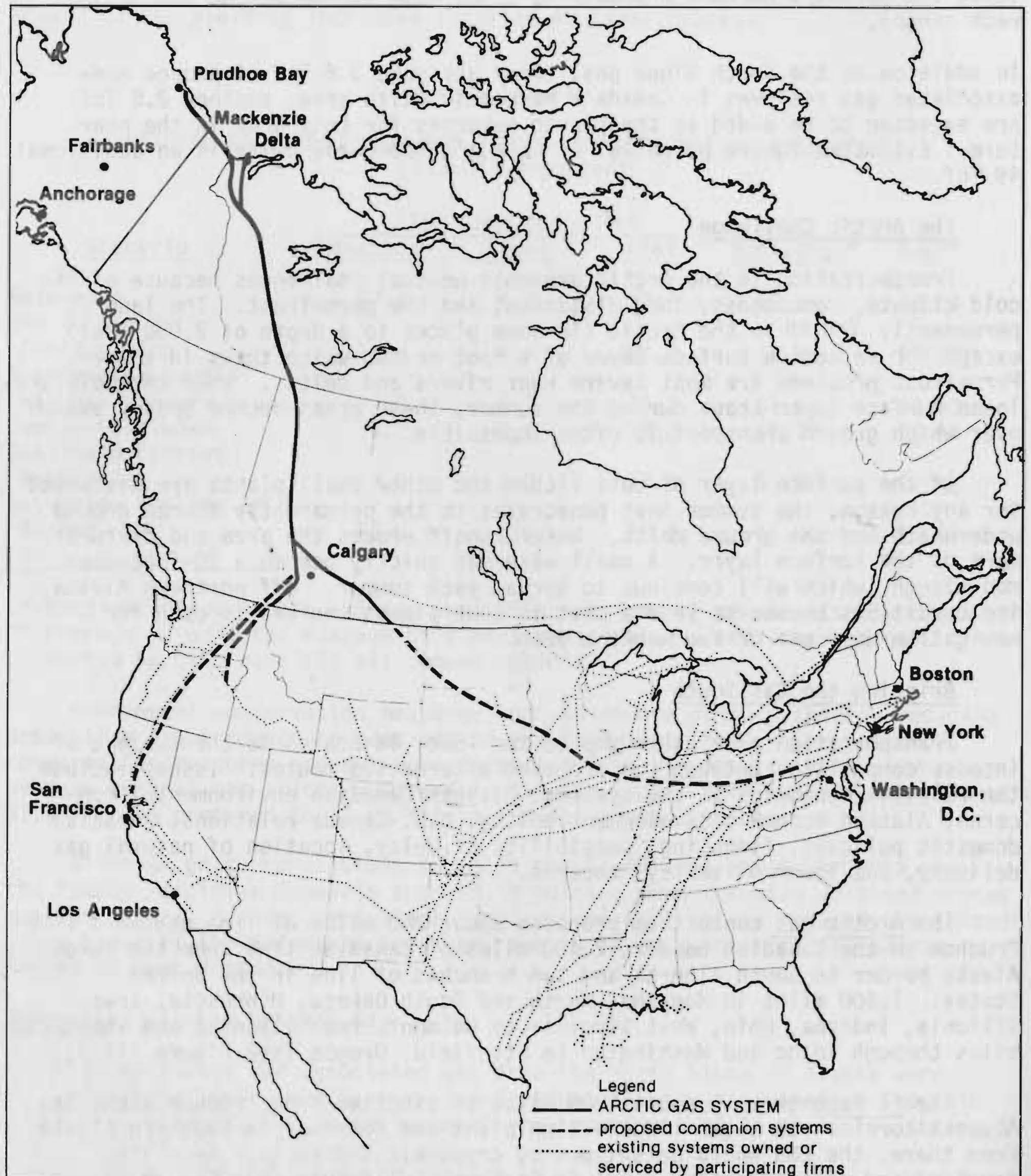


Figure III-10
Proposed El Paso System

Legend
Envisioned Natural Gas Switching
LNG Carrier Trade Route
Trans—Alaskan Gas Pipeline

and East Coast by switching present East-to-West supplies of Gulf Coast natural gas from West Coast markets to the East (this concept is known as displacement). This would require construction of an additional 540 miles of pipeline in the lower 48 states.

Further, an all-Canadian proposal by (Maple leaf) Foothills Pipeline, Ltd., from the Mackenzie Delta south to Alberta, is being considered by the Canadian government.

Recently Arctic Gas has estimated its pipeline capacity in Alaska at 0.8 Tcf/yr; El Paso designed its proposed system to fit a projected Prudhoe supply of 1.2 Tcf/yr. If one system is expedited and encounters no serious delays, the lower 48 could be receiving 0.8 to 1.2 Tcf/yr (2.1 to 3.2 Bcf/day) of Prudhoe gas by 1985--at an estimated cost of $2.50 to $3 per Mcf including transportation to U.S. borders.

Comparison of Costs and Benefits of Alternate Routes

Final details of the two routes to the lower 48 States have not yet been settled. Accurate cost comparisons are not possible because each of the two groups used not only a different assumed gas supply from Prudhoe, but also differing base year dollar values. However, extrapolation from information available last fall indicated that the Arctic Gas proposal could cost between $8.5 and $9.7 billion (in 1975 dollars) and the El Paso proposal between $7.5 and $9 billion. Canada's cost share of the Arctic Gas proposal could be $1.3 to $1.7 billion.

The two proposals differ fundamentally, and each offers its own set of benefits. El Paso maintains that its proposed system bypasses any possible complications arising from routing the Arctic Gas line through Canada. El Paso points out the advantage to the U.S. economy and the Treasury of having all the payments for construction and operation of its system accrue solely to the United States. El Paso also says its system will give a bigger economic boost to Alaska. Arctic maintains that the Canadian route for Alaskan gas that also accesses Canada's Mackenzie reserves offers better economies of scale and cheaper ultimate costs to U.S. consumers.

Each system has its own set of potential environmental difficulties and possible sources of delays. The Arctic proposal could threaten disruption of the Arctic National Wildlife Range in Northeast Alaska, while the El Paso plan may increase maritime traffic in the Gulf of Alaska and Prince William Sound. Delays in project completion under the Arctic plan could be caused by difficulties in resolving Canadian taxing issues and Northwest territories native claims, and by the larger requirement for construction activities to be undertaken north of the Arctic Circle. El Paso faces possible engineering delays because it would utilize larger liquefaction facilities and LNG tankers than have been previously built.

Among the most important unresolved issues is the regional impact of each competing system. Alaska, California, Midwestern, and North Central States all have a direct interest in the decision, as do the shipbuilding states where El Paso's LNG tankers would be built.

Whereas the Arctic Gas line would run only 195 miles through uninhabited Alaskan terrain, the El Paso line would lay four times as much pipe and build an expensive liquefaction plant in Alaska--thus, continuing the Alyeska oil line boom in southern Alaska.

The El Paso system would require a terminal, regasification plant, and pipeline in California to link up with existing lines. The Arctic Gas line would include pipeline construction in Montana, North Dakota, South Dakota, Minnesota, Iowa, Illinois, Indiana, Ohio, and Pennsylvania. In Montana and western North Dakota, pipeline construction would draw out-of-state construction workers and shift workers into construction from other occupations.

In summary, although the choice between competing pipeline proposals cannot be made until the relative costs and benefits of the systems are more clearly defined, the construction of a natural gas pipeline from Prudhoe Bay is critical to the U.S. economic and energy interests. The 0.8 to 1.2 Tcf that could be available in 1982 could reduce oil import requirements by about 500,000 barrels a day.

The Role of Imported Liquefied Natural Gas (LNG)

LNG is natural gas of pipeline quality (1000 Btu/cf or higher) which is converted to liquid form by reducing the gas temperature to -259°F. The liquefaction process reduces volume by a factor of 623:1, and consumes approximately 15 percent of the gas energy supplied at the liquefaction plant. Additional energy losses are incurred through production, gathering, and transmission from the wellhead to the liquefaction plant.

Large scale liquefaction and ocean shipment of gas as LNG are relatively recent developments, resulting from the fact that countries such as Abu Dhabi, Algeria, Indonesia, Iran, Libya, and Nigeria have developed sizable proved reserves of natural gas, but have no means at present to deliver this gas by pipeline to potentially large consuming markets.

An average sized LNG project in international trade would deliver approximately 1 Bcf/day or over 0.3 Tcf per year. For a U.S.-Algeria trade project delivering 1 Bcf/day and using current design technology, one liquefaction facility, eight 125,000-cubic meter tankers (8,000-mile round trip trade) and a terminal facility capable of handling one ship every 2-1/2 days would be needed. The following is an estimate of the investment cost for such a system delivering gas in 1980 from Algeria to an East Coast port:

Investment Items	Cost--$Million, 1975 Rate
Liquefaction Facility	1,000
8 Tankers (8,000 mile round trip, Algeria U.S.)	1,300
Receiving Terminal and Regasification Facility	300
Total	2,600

This investment cost of about $2.6 billion results in considerable additions to the wellhead price of the exported natural gas for liquefaction, transportation, and regasification. Consequently, at current world prices the producer country's "take" (profit) from LNG exports is considerably less than the equivalent "take" from the export of crude oil. Based on F.O.B. prices of $1.30/Mcf for LNG, North Africa, and $11.51/barrel for marker crude, Persian Gulf, producer country "takes" are $.30/Mcf and $11.00/barrel respectively, or 23 percent vs. 96 percent of F.O.B. price.

The pricing strategy of some LNG exporters has been to seek an oil Btu equivalent price for LNG at the port of embarcation. This has been the Libyan strategy to date, although it has encountered severe resistance in buying markets. A strategy currently being followed by the Algerians in negotiations with U.S. companies is to price against a competing fuel in the consuming country.

A major factor in determining the demand for imported LNG will be the manner in which the FPC allows LNG to be priced domestically. In the only two cases previously approved by the FPC, imported LNG was to be priced on an incremental basis, thereby disallowing averaging in the higher costs of LNG with cheaper domestically produced natural gas.

Potential Sources of LNG

Although Iran, and Algeria have large gas reserves, Algeria is the only one of these nations actively seeking a large LNG export market because of its substantially higher gas/oil reserve ratio and low oil export revenues (see Table III-22). One country with large reserves not listed on Table III-19 is the U.S.S.R. (estimated reserves in excess of 800 Tcf).

Table III-22

OIL AND GAS DATA FOR POTENTIAL LNG SUPPLY SOURCES

Country	Oil Reserves (Billion Barrels)	Gas Reserves (Tcf)	Gas: Oil Reserve Ratio	Oil Production (1975 MB/D)
Algeria	7.4	126.0	17.0	935
Indonesia	14.0	15.0	1.1	1,300
Iran	64.5	329.5	5.1	5,600
Libya	26.1	26.3	1.0	1,400
Nigeria	20.2	44.3	2.2	1,850
Abu Dhabi	29.5	20.0	0.7	1,500

Source: Oil and Gas Journal, December 29, 1975

Potential Import Levels

It is unlikely that new LNG projects will be able to come on stream until after 1985 unless they are in the initial planning stages at this time, due to the long lead times for the regulatory process and for construction of tankers and facilities. Thus, maximum LNG import quantities in 1985 are now defined, and several alternative levels can be assumed.

- Most conservatively, it could be assumed that only the projects already unconditionally-approved by the FPC will materialize, i.e., the Distrigas I and El Paso I ventures; this would result in annual LNG imports of 0.4 Tcf in 1985 (LNG Supply Case I).
- Alternatively, it could be assumed that in addition to the above ventures, projects which have been submitted to the FPC for approval would also materialize; annual supply by 1985 would total 1.5 Tcf (LNG Supply Case II)
- Finally, projects announced in Iran and Nigeria but not yet submitted to FPC for their review could be developed, resulting in a 1985 supply level of 2.1 Tcf (LNG Supply Case III).

The possible levels of U.S. LNG imports in 1980 and 1985 are shown below:

Table III-23

ALTERNATIVE LNG SUPPLY CASES
(Tcf/yr)

	1980	1985
Case I	.4	.4
Case II	0.9	1.5
Case III	1.3	2.1

In all three cases, Algeria emerges as the major source of LNG imports for the United States, ranging in 1985 from 100 percent of supply in Case I to about 70 percent in Case III. This results not only from Algeria's advantageous location with respect to consuming markets, but also from its determination to market its vast gas reserves, since its oil reserves are relatively limited.

Dependence Upon LNG Imports

Determining regional dependence on LNG imports is difficult because most of the companies that import gas serve more than one region and also sell to transmission companies serving other regions.

Although regional dependence could go as high as 10 percent, the dependence of customers served by the importing pipeline companies will be much greater. Of the seven projects filed with the FPC, individual pipeline company import dependence could range between 9 and 29 percent of current annual sales. Regional and company dependence are important because of the potential for sudden interruption or abrupt increase in price.

Other Issues

Although dependence, vulnerability, and pricing are the significant major issues associated with LNG, there are several other potential problems. While exporting countries have traditionally constructed and owned the liquefaction facilities, the financing of such facilities has originated within the importing country through government agencies such as the Export-Import Bank of the United States. These Export-Import Bank loans for liquefaction facilities, along with Maritime Administration loan guarantees and subsidies for LNG tankers, must be reviewed and coordinated with national policy towards LNG. Safety and environmental concerns have delayed the use of some terminals, particularly in densely populated harbor areas such as the New York Harbor.

In summary, it is clear that some supplemental LNG imports will probably be required in the next decade or two to assist the United States in meeting energy demands placed on the natural gas pipeline and distribution system. However, excessive dependence on the supplies must be avoided due to the consequent vulnerability to arbitrary price increases and sudden interruptions in supplies, as in the case of oil imports.

Synthetic Gas From Coal

The extraction of methane from coal has been demonstrated in several pilot plants, both in the United States and abroad. This process offers the U.S. a mid-term capability to make greater use of coal reserves to supplement domestic natural gas supplies.

However, the commercial viability of a high Btu synthetic gas venture has not yet been demonstrated in the United States. Present estimates indicate that an investment of about $1 billion will be required to construct a high Btu gas plant capable of producing 0.08 Tcf/yr (assuming a debt/equity ratio of 75:25). About $525 million would be required to finance construction of a low Btu gas plant producing the equivalent of 0.05 Tcf/yr (assuming a debt/equity ratio of 50:50). The full costs (i.e., without incentives of both high and low Btu synthetic gas processes, expressed in 1975 dollars on an F.O.B. gasification plant basis, are expected to range as shown in Table III-24.

Additional costs will be incurred in transmitting the high Btu gas output to consuming areas; these costs will vary depending on the proximity of the synthetic plants to natural gas transmission networks and consuming markets. Pacific Lighting estimates that transmission and distribution costs to its proposed WESCO (Western Gasification Company) venture in New Mexico with its

Table III-24

COSTS OF SYNTHETIC GAS PROCESSES IN $/MCF*

Cost Category	High Btu Gas Plant Low Estimates	High Btu Gas Plant High Estimates	Low Btu Gas Plant Low Estimates	Low Btu Gas Plant High Estimates
Fixed Costs	1.02	1.38	1.77	2.40
Operating and Maintenance	.82	1.01	.61	.76
Feedstock of $11** to $17/ton	1.19	1.84	.72	1.11
Total at Plant	3.03	4.23	3.10	4.27

* Derived from Draft Synthetic Fuels Commercialization Report, submitted to the President's Energy Resources Council, dated June 1975.

** Feedstock cost of coal could also be estimated at $5 to $9/ton to account for East, West regional experiences in the cost of coal production; with this lower feedstock cost, high Btu gas would range between $2.38 and $2.34/Mcf.

service area in Southern California would add 32¢/Mcf to the city gate price, increasing the price to a range of $3.35 to $4.55/Mcf.

The technology involved in the production of low Btu gas is well developed and is currently applied in many commercial plants outside the United States. Actually, coal gasification was prevalent in the United States for producing "town gas," that is, gas produced locally for community consumption purposes only, prior to the establishment of natural gas pipelines. A limiting factor in the use of low/medium Btu gas is that it is not economically feasible to transport it more than about 50 miles. This may be an inhibiting developmental factor if a plant is intended to generate electricity to residential, commercial, and industrial users in urban areas.

Current Industry Plans and Major Constraints

Although industry is considering a number of synthetic fuels projects, none has actually proceeded to the construction stage in the United States. Six major projects involving high Btu gas from coal are currently being planned. Several low Btu gas projects related to utility and industrial fuels have been suggested, but have not yet reached the level of planning associated with high Btu gas projects. None of the projects has yet acquired the necessary financing and other approvals needed to proceed. Only a few projects have actually reached the detailed design phase.

The major reason the projects have not proceeded is that the risks associated with initiating synthetic fuels projects are large compared with other investments providing an equal or higher rate of return. A major risk is the uncertainty concerning the future price of world oil. For instance, high Btu coal gasification projects need an equivalent of $19 per barrel to have an acceptable return on investment. Other important risks include:

- Uncertainty about air and water quality standards;
- Resource (coal, shale, biomass) availability as constrained by leasing rates and environmental concerns;
- Water availability;
- Federal regulation of price of fuels;
- Availability of labor, materials and equipment;
- Need for environmental control technology;
- Extent of socioeconomic impact;
- Unforeseen project delays.

With the proper financial incentives, the development of high and low Btu gasification plants can accelerate rapidly after 1980 and could reach about 1,060 Bcf by 1985 and 1,440 Bcf by 1990.

The Potential for Increased Use of Substitute Natural Gas

Substitute natural gas (SNG) can be made from liquid petroleum feedstock such as crude oil, naphtha, and LPG (propane and butane), through catalytic conversion of the feedstock into a methane-rich gas of high Btu content (about 850 Btu/cubic feet), and further treatment, such as methanation, CO_2 removal or propane enrichment which increases the heat value of the gas to pipeline quality. In the naphtha process, about 90 percent of the feedstock is converted into gas; the remainder is consumed as process fuel or lost; the tehcnique is generally known as naphtha reforming.

Some existing SNG plants are primarily used for peaking purposes, operating at full design capacity for only 150 days per year. Certain other plants are running currently at less than practical operating capacity for 350 days a year, due to insufficient feedstocks as limited by government regulations. If the plants constrained by feedstock availability were provided sufficient feedstock, an additional 10 Bcf per year of SNG would be produced. If, in addition, all existing plants were run at practical operating capacity, a total of about 95 Bcf/yr of additional production could be obtained, or 0.4 percent of total natural gas use.

There are 13 SNG plants currently in operation and three under construction in the United States. Eight of these plants are naphtha reforming units, while the others are peak-shaving plants which utilize light petroleum liquids as feedstock. The combined capacity of these plants, when all are operational,

is estimated at about 0.5 Tcf/yr; all 16 facilities should be on stream by 1977. In addition to these units, there are five other SNG plants in various stages of planning. The major uncertainty which appears to be delaying activation of these projects is the availability of feedstock, principally naphtha. Assuming all plants currently planned are constructed, the SNG contribution to natural gas supply could amount to approximately 1.5 Tcf by 1985; more realistically, about 1 Tcf can be anticipated.

Because of rising prices for feedstocks and the plant facilities, the cost of SNG is extremely high (between $3.50 and $5.20 per Mcf, as compared to about 52¢/Mcf for new interstate gas, and $2.30 to $3.10 for LNG), making it the most expensive source of gas supply available today. For plants operating at less than full capacity or only for part of the year, SNG cost is even higher because of the reduced levels of plant outputs over which the plant operating and maintenance costs must be prorated.

The ultimate cost to the consumer will vary depending on whether the gas is sold incrementally or on a "roll-in" basis. In the event the sale of the SNG is subject to FPC jurisdiction (i.e., the SNG is commingled with gas sold for resale in interstate commerce), the Commission has ruled in all cases to date that it will be sold on an incremental basis. For SNG subject to state regulatory jurisdiction, which is the case for most of the SNG plants operating or under construction today, "rolled-in" pricing has been the policy adopted by most states.

Problems exist with either form of pricing when SNG is being added to pipelines to supplement natural gas supplies. When priced incrementally, the gas is generally produced and purchased only on a seasonal basis to satisfy peak-shaving needs by utilities. This causes extremely high production costs for SNG and a disincentive to construct SNG plants.

Where SNG prices are allowed to be "rolled-in" with cheaper domestically produced natural gas, there exists an economic incentive to run the plants at full capacity throughout the year and thus substitute SNG for unavailable domestically produced natural gas supplies. As a result, naphtha and LPG feedstocks, in the absence of an allocation system, would be bid away from traditional users, such as farmers and industrial users, to be used in an SNG production process where about 10 percent of the feedstock is lost in conversion.

In summary, approximately 1.0 Tcf of SNG from petroleum products is forecast to be available in 1985 given current plant capacity and those expected to be constructed under incremental pricing policies. Since SNG is produced from petroleum, it is not distinguished from petroleum in FEA forecasts.

Gas From Tight Formations

Natural gas is also found in tight (low permeability), thick, massive sand and shale deposits located predominantly in the Rocky Mountain states. A significant portion of this resource is believed to be in the Green River Basin of Wyoming, the Piceance Basin of Colorado and the Uinta Basin in Utah.

The FPC has estimated gas reserves in these areas at the following levels (as compared to 439 Tcf of demonstrated and inferred reserves from other areas):

	Tcf
Green River Basin, Wyoming	240
Piceance Basin, Colorado	210
Uinta Basin, Utah	150
Total	600

These formations require extensive fracturing, if the gas is to be produced on a commercial basis. There are two approaches, applying entirely different technology, potentially capable of creating the fracture systems for production. These are the nuclear explosive and the massive hydraulic fracturing methods. The nuclear explosive method has been tested and failed to provide access to the fully stimulated zone. In addition, this method has resulted in unfavorable public response regarding possible environmental and safety hazards, which could pose a major constraint in its use.

If either stimulation process can be made effective and is properly employed, cumulative recovery could reach 40-50 percent of the gas in place. Estimates of the amount of natural gas that could be produced from these formations in 1980 and 1985 are difficult to derive since the fracturing technologies have not yet been fully developed. Additionally, the actual quantities of gas in these formations are highly speculative.

Finally, the present controls on natural gas pricing at the wellhead adversely affect the willingness of industry to proceed with commercial development plans. FEA estimates that 0.2 to 0.9 Tcf/yr could be produced by 1985, depending upon the level of investment.

Gas From Devonian Shale Formations

The Devonian gas shales are geologic formations underlying an area of approximately 250,000 square miles in the Middle and Eastern sections of the United States. Trapped within the shale is an unknown, but potentially very large quantity of natural gas. In order to produce gas from these shales, it is not possible to employ the standard drilling techniques commonly used in producing natural gas; rather, advanced massive fracturing techniques are required. These techniques have been employed on a small scale, but major technological developments will be necessary before commercial quantities of gas can be extracted.

Devonian shale formations are extensive in parts of Ohio, Illinois, Indiana, Kentucky, Alabama, Tennessee, West Virginia, Pennsylvania, and New York.

If a major, rapid development program were undertaken, it might be possible for sufficient quantities of natural gas to be produced from local resources to enable these states, which, in many cases, are those most affected by the current shortage, to have an adequate gas resource base.

The principal difficulty stems from the lack of accurate data on the potentially recoverable volumes of natural gas. The U.S. Geological Survey does not include either gas from Devonian shale or tight formations in current resource estimates because, although both types of formations are known to have great potential, no feasible method for commercially extracting the gas has been found. Existing industry estimates, based on extrapolations from limited geological data, value the reserves on the order of 285 Tcf in Ohio, West Virginia, Pennsylvania, Kentucky, and New York. This estimate must be evaluated in the context of a proven gas reserve estimate of 237 Tcf for the entire United States in 1974.

Once the gas-bearing shale formations have been located, technological and economic hurdles will have to be overcome in order to develop this potential resource and to produce significant quantities of natural gas. Because of the lower delivery rates of gas from wells drilled in Devonian shale as compared with sandstone formations, large numbers of wells must be drilled in shales using current technology to produce significant quantities of gas. Columbia Gas, for example, has estimated that using today's technology to develop 250 million cubic feet daily (91 Bcf/yr) would require 3200 wells the first year at a cost of $285 million. In the next 11 years, 3100 wells and $280 million would be required to sustain that rate of gas production. Thus, the cost of this gas would be over $3.50/Mcf. Further research could reduce the cost of wells as well as increase their productivity. New stimulation technology could reduce the requirement for wells by as much as a factor of 10. Because of the high costs associated with the production of gas from Devonian shales, higher prices and further technological development will be necessary to obtain gas from this source.

ERDA has contracted for three experimental wells to be drilled in the West Virginia-Eastern Kentucky area. This pilot project is primarily designed to improve hydraulic fracturing techniques and evaluate the gas extraction potential from an area where much is known about the underlying geological structure.

In conclusion, Devonian gas shale formations may produce as much as .09 Tcf/yr with conventional technology by 1985 at a cost of over $3.50/Mcf. Thus, it provides little prospect for near- or mid-term relief in the context of the current shortage.

SUMMARY

The most significant impact on domestic natural gas supply is derived from the degree of price controls extended over oil and gas (see Table III-25). If existing regulations over natural gas continue and oil prices are decontrolled, about 17.9 Tcf of gas will be produced in 1985. Equally important is the fact that under these conditions the interstate natural gas market would decline to 6.6 Tcf in 1985 from 11.6 Tcf in 1974. If instead, current

Table III-25

POTENTIAL SUPPLY OF NATURAL GAS AND SUPPLEMENTS

Supply Source	Decision/Action	Price ($/Mcf)	1985 Supply (Tcf)
Lower 48 and Southern Alaskan (BAU), including the North Slope and Tight Formations	.Extend controls to intrastate gas market; maintain oil controls.	0.52	9.2
	.Extend controls to intrastate gas market; decontrol oil.	0.52	10.8
	.Maintain ceiling of $1.00 on gas and existing controls on oil.*	1.00	17.0
	.Maintain existing controls on gas; deregulate oil.*	1.24	17.9
	.Decontrol oil and new gas.*	2.03	22.3
Prudhoe Bay, Alaska	.Construct pipeline by 1982	2.50-3.00	0.8-1.2
Offshore Areas	.Accelerate leasing by 45% in acreage	2.03	0.5
Synthetic Gas From Coal	.Implement two-phase program		
	-High Btu	3.03-4.23	0.6
	-Low Btu	3.10-4.27	0.5
SNG From Petroleum Products	.Maintain incremental pricing method.	3.50-5.20	1.0
Imported LNG	.Discourage LNG imports.	2.14-3.00	0.4
	.Approve projects already submitted to FPC	2.14-3.00	1.5
	.Encourage LNG imports	2.14-3.00	2.1
Tight Formations	.Develop fracturing technologies	0.80-2.22	0.2-0.9
Devonian Shale	.Apply conventional technology.	Over 3.50	0.1

* Includes 0.8 Tcf from Prudhoe Bay since the Alaskan Pipeline is assumed constructed; also includes 0.2 Tcf from Tight Formations. These are also included in the totals shown in each respective supply source category.

regulations are extended to the intrastate market and maintained at the current 52¢/Mcf level, along with regulation of oil prices, about 9.2 Tcf of natural gas can be anticipated in 1985 (almost 60 percent less than 1974 levels). However, if oil and gas prices are deregulated, 22.3 Tcf will be produced in 1985.

Selection of one of the two alternative routes to transport natural gas from Northern Alaska could provide 0.8 to 1.2 Tcf to the "Lower 48" States by the early 1980's (0.8 Tcf is included in the Reference Scenario). Also, if leasing in the offshore areas is accelerated above current expectations, an additional 0.5 Tcf can be produced by 1985.

The volumes of natural gas supplements available by 1985 are almost completely dependent on government energy policies. The announced synthetic fuels commercialization program could result in the production of 1.1 Tcf of synthetic gas by 1985. LNG imports could increase to up to about 2 Tcf by 1985, but would be 0.4 Tcf if no further project applications were approved. The availability of substitute gas from petroleum products will depend greatly upon the price of oil, the availability of feedstocks and the method of pricing when injected into pipelines and distribution gas lines. At current price levels and with an incremental pricing policy maintained, about 1.0 Tcf of SNG will be produced in 1985 (as compared to 0.5 Tcf currently).

If the natural gas resource base is made further accessible, such as through development and application of advanced fracturing technologies, natural gas from tight formations and Devonian shale would reach about 1.0 Tcf by 1985. (Only about 0.2 Tcf of gas from tight formations is included in the Reference Scenario).

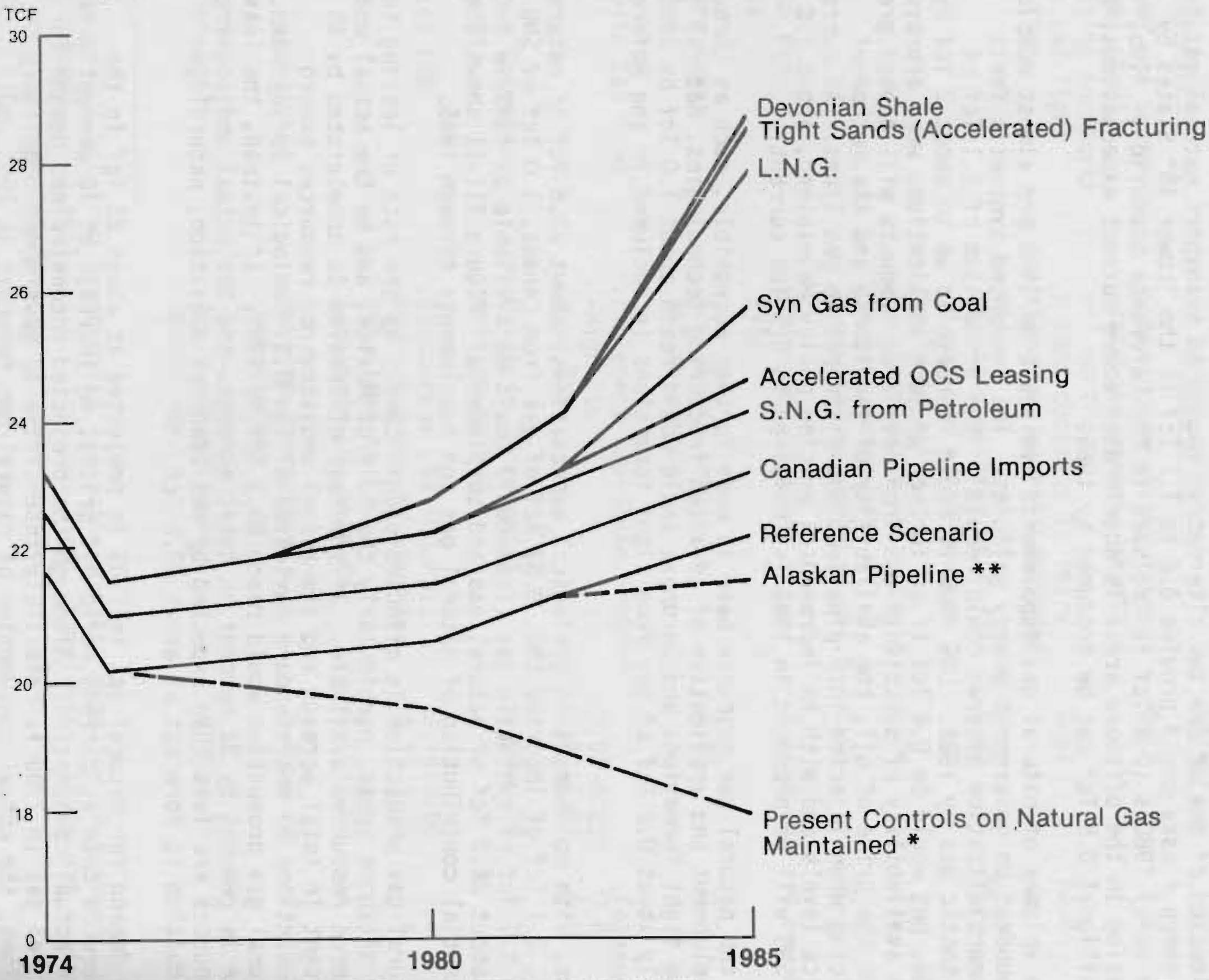
Thus, with no changes in geological expectations, about 23.6 Tcf of natural gas, 2.1 Tcf of imported LNG, 0.87 Tcf of gas from Canada, 1.0 Tcf of SNG and 1.1 Tcf of synthetic gas (from coal) could be available by 1985--a total of about 28.7 Tcf of natural gas and supplements. Figure III-11 shows the potential contribution of natural gas and supplements through 1985.

Natural gas production is affected significantly by the rate of leasing in the offshore areas, particularly the Gulf of Mexico, and by the actual undiscovered resources available. If the rate of leasing is accelerated by 45 percent in total acreage and the actual undiscovered resources exceed expectations by one standard deviation of the U.S. Geological Survey mean, natural gas production would reach 25.3 Tcf by 1985. If instead, the leasing rate is reduced by 32 percent in total acreage, and the actual undiscovered resources are less than expected by one standard deviation, natural gas production is forecast at about 20.5 Tcf.

The demand for natural gas in 1985 is projected at about 23 Tcf in the Reference case at current world oil prices, an increase of 10 percent over 1974 actual consumption. Although the projected unconstrained demand for natural gas in 1985 is relatively insensitive to government regulatory actions, the actual consumption of natural gas forecast in 1985 would decrease with continued price regulations over oil and gas due to the lack of available supplies, necessitating the substitution of alternate fuels and increased oil imports.

Figure III-11

Potential Marketed Production of Natural Gas and Pipeline Supplements Through 1985



* This component not added into total ;illustrates alternative to reference scenario

** Illustrates contribution within reference scenario by Alaskan pipeline